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A Holistic Analysis of Renewable Hydrogen Production and Usage in order to Minimize Otherwise Curtailed Power

THESIS

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by

Sarah ML Wang

Thesis Committee:

Professor G. Scott Samuelsen, Chair

Professor Sunny Jiang

Professor Donald Dabdub

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DEDICATION

I dedicate this thesis to my family - 媽媽, 爸爸, Cathryn, and Mark - in recognition of their support and encouragement.

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Nomenclature

P2G	Power-to-Gas
GHG	Greenhouse Gas
RPS	Renewable Portfolio Standard
ZEV	Zero Emission Vehicle
EV	Electric Vehicle
FCV	Fuel Cell Vehicle
MPG	Miles per Gallon
APEP	Advanced Power and Energy Program
PFCV	Plug-in Fuel Cell Vehicle
NG	Natural Gas
ES	Energy Storage
HES	Hydrogen Energy Storage
BES	Battery Energy Storage
SOEC	Solid Oxide Electrolyzer
HED	Hydrogen Electrolysis Dispatch
LCOE	Levelized Cost of Energy

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Abstract of the Thesis

A Holistic Analysis of Renewable Hydrogen Production and Usage in order to Minimize Otherwise Curtailed Power

By

Sarah ML Wang

Master of Science in Environmental Engineering

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Professor G. Scott Samuelsen, Chair

Renewable resources, such as wind and solar, exhibit variability which require the electricity grid to be more flexible in order to accommodate their integration into the system. In addition, events can occur where renewable generation exceeds the electricity demand at a given time and must be curtailed to maintain the balance between load and generation, representing a waste of valuable renewable generation. Power-to-Gas (P2G) refers to a class of technologies which can provide the functions of dispatchable loads and/or energy storage to the electricity system. In particular, power (P) is used to produce hydrogen gas (G) from water through electrolysis. The hydrogen can then be stored, transported (e.g., through natural gas pipelines), and eventually used as a transportation fuel and the generation of renewable electricity to meet load demands.

This work analyzes the economic potential and CO_2 emission associated with installation of different P2G use cases: pure hydrogen or hydrogen converted into methane injection into the natural gas pipeline system to offset natural gas; hydrogen fuel for fuel cell vehicles; storage of hydrogen to be used in a fuel cell to provide renewable electricity generation back to the electricity system. It is found that hydrogen fuel use case results in the largest CO_2 emission reduction since it offsets high CO_2 emitting gasoline vehicles. The economics, due to dependency on many factors such as capacity factor, operational parameters, as well as the price of electricity, do not result in a clear use case of best values.

1 Introduction

The world population is projected to reach 9 billion in 2042 which will lead to an increase in energy demand [1]. The current energy infrastructure heavily relies on carbon based fuels such as coal or natural gas, which emit greenhouse gases (GHGs) and pollutants [2]. In order to protect the environment, air quality, and quality of life, different renewable and alternative energy technologies must be considered and implemented [3].

Integration of renewable power is the key to reducing emissions. But, renewable energy, such as wind and solar, have high intermittency and variability; more flexibility will be needed within the power generation system [4]. Generators must adjust to accommodate the variability of renewable energy which may increase ramping rates [5]. An increase in ramping rates may lead to higher emissions. Technologies are needed to help smooth out the load and balance generation in order to allow full integration and reliance on renewable energy.

A number of options are available for managing the variability of wind and solar resources. These include dispatchable loads where electric loads are shifted to better coincide with renewable generation and energy storage where renewable generation is captured and stored for use on the electricity system at a later time [6]. These technologies can capture renewable generation when it would otherwise be wasted and either use it for a productive purpose such as fuel production or store it for later use. These functions reduce reliance on non-renewable and carbon-intensive generation to maintain the balance between load and generation [7].

1.1 Goal

The goal of this research is to:

Evaluate hydrogen as a potential energy storage source and determine the feasibility of using (1) curtailed renewable power to produce hydrogen, (2) different methods to store and convey the hydrogen, and (3) environmentally-sensitive options to recapture the stored energy when the load demands.

1.2 Objectives

The objectives of this thesis are:

1. To add a module of an infrastructure for the generation, storage and distribution, and usage of hydrogen to the Holistic Grid Resource Integration and Deployment Tool (HiGRID).
2. To utilize HiGRID as a tool to:
    a. Characterize the role of hydrogen as a storage medium.
    b. Establish scenarios for incorporating hydrogen into the electric grid.
    c. Analyze the manner by which hydrogen storage, hydro storage, and electric battery storage complement, compete, and/or adversely affect each other in the context of overall grid performance.
3. To determine the environmental impacts of hydrogen generation, storage and transport, and utilization in terms of greenhouse gas emissions.

2 Background

Hydrogen has been referred to as the “Freedom Fuel” and has been viewed as the solution to many problems in the energy crisis [8]. Hydrogen provides the U.S. with dependency from foreign oil, a long-term energy solution, and a way to improve the environment. Figure 1 displays a potential future power system which connects and relies on many different components [9]. The green line represents the future hydrogen infrastructure. Hydrogen can be produced through curtailed renewable power, when solar or wind energy has high production with low load demand [10]. The utilization of curtailed power to produce hydrogen not only allows for hydrogen production to be sustainable, but it also offers a potential solution for balancing the grid and increases the penetration of renewables into the electric grid. The produced hydrogen could be stored and used in a fuel cell to support the electric grid at a later time or used for fueling fuel cell vehicles [11].

In Figure 1, hydrogen is mostly produced through central generation and distributed through a hydrogen dedicated pipeline. Approximately 1,600 miles of hydrogen pipelines are currently operating in the United States [12]. This is relatively small compared to the 2.44 million miles of pipes for natural gas, but it proves that it is possible for a pure hydrogen pipeline [13]. Also, before the hydrogen pipelines are installed it is possible to inject hydrogen into the natural gas pipeline and take advantage of the already established infrastructure [14]. It may be possible to eventually replace the natural gas with hydrogen in order to completely reduce emissions and rely purely on renewable power.

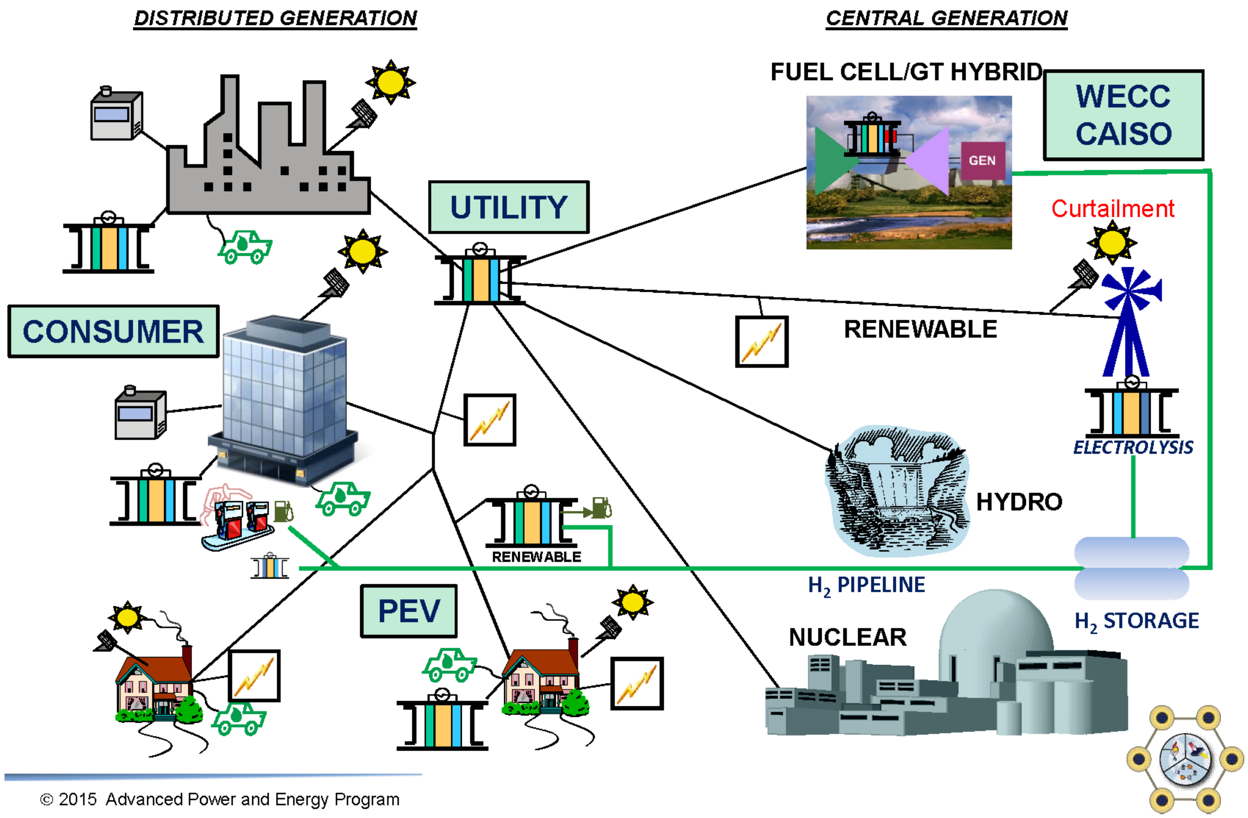

Figure 1: A diagram of the future electric grid with renewable integration. Nuclear energy, hydro energy, wind energy, and fuel cell/gas turbine hybrids are mainly generated centrally while solar power could either be central or distributed generation. There are batteries which stores excess electricity or provides energy for transportation. There is also a dedicated H_2 pipeline which is able to transport hydrogen produced from renewable power or captured from the fuel cell/gas turbine hybrid. This hydrogen pipeline is the large focus of this figure as it shows how hydrogen can lessen the dependence on natural gas and support the electricity sector as well as the transportation sector through fuel cell vehicles. This figure is from the Advanced Power and Energy Program at the University of California, Irvine.

2.1 California State Bills

California has enacted legislation to enforce future renewable goals. SB 350, the Clean Energy and Pollution Reduction Act of 2015, states an increase in the renewable portfolio standard (RPS) from 33% to 50% for 2030 and beyond. An increase in RPS pushes for the installation and integration of more renewable energy sources. And with an increase in reliance on renewable power, energy storage is necessary. AB 2514 states the need for energy storage to reduce peak demand and need for peaker plants with the goal to minimize emission of carbon dioxide, GHGs, and criteria pollutants. Since the power generation in California is already relatively clean, it will be important to consider the potential emission reductions in the transportation sector as well. B-16-2012 states California's goal of having 1.5 million zero emission vehicles (ZEV) by 2025 [15]. These laws have resulted in an increase installation of renewable electricity generation which will continue into the future to meet policy goals work in tandem in order to target emission problems in the different divisions of the energy sector [16].

2.2 Current Condition

The South Coast Air Basin of California exhibits some of the worst air pollution in the United States [17]. This air pollution is due to an inversion layer which traps emissions from ventilating into the troposphere. In particular, the Los Angeles basin is surrounded by mountains on three sides and opens to the Pacific Ocean in the southwest [18]. This need for clean energy has driven California in becoming a leader in green technology, reducing per capita GHG emissions as economy and population grows [19].

Different sectors contribute to energy consumption and emissions. The largest contributor to energy consumption is the Industrial Sector, followed by the Transportation Sector [20]. But, the gap between the Industrial Sector and the Transportation Sector has decreased over time. The Industrial Sector has been able to reduce CO_2 emissions by upgrading energy efficiency, switching fuels, and recycling [21]. Gas engines for transportation can only achieve up to around 30% efficiency [22]. This efficiency limitation prevents the current technologies from further reductions of energy usage in the Transportation Sector. The gasoline dependent engines need to be replaced with alternative vehicles which can reach efficiencies up to 50% and are environmentally benign.

Even though the Industrial Sector has a larger energy consumption than the Transportation Sector, the Industrial Sector has been successful in decreasing CO2 emission while the Transportation Sector shows an increasing trend according to data from the U.S. Energy Information Administration [23]. Transportation accounts for 28% of total energy yet it accounts for over 30% of all carbon dioxide emissions [24] & [25]. The Transportation Sector has a high potential of CO_2 reduction since the primary fuel used is petroleum, 89% of all fuels [26]. Replacing petroleum with a cleaner fuel could potentially decrease over 20% of all CO_2 emissions. Petroleum based vehicles can be replaced with hydrogen fuel cell vehicles (FCVs) or electric vehicles (EVs) which could completely negate the use of carbon based fuel and CO_2 emissions from the Transportation Sector.

As vehicles switch to alternative, non-carbon based, fuels energy is still consumed but in a different form. Currently, only 3% of fuel used for transportation is not dependent on carbon based fuels [26]. But, as the percent of alternative fuel transportation increases the effects of energy consumption will be seen in other sectors or energy sources. The CO_2 emissions from the Transportation Sector may be shifted to another sector. For example, if an electric car charges at home the energy consumption in the transportation sector transfers to the residential sector. With an increase in energy in the residential sector, more electric power plants would need to be installed and the operation of the grid may change. Although, if the electricity system is relatively clean, there could be a net decrease in CO_2 emissions by switching from a gasoline vehicle to an electric vehicle.

The potential of EVs are shown in a study by the Union of Concerned Scientists which determined what the miles per gallon (MPG) of a gasoline vehicle would have to be in order to produce GHG emissions equivalent to an electric vehicle charging from the electric grid of different states in the United States [27]. Some states have very high MPG requirements, Alaska has an MPG of 112. This shows that a gasoline vehicle, which is around 30 MPG, would have to be four times more efficient in order to be equivalent to an EV in Alaska [28]. This suggests that switching from gasoline vehicles to EVs could result in a reduction of GHG emissions.

2.3 Power Infrastructure

In the electricity sector in California, around 25.05% of total power capacity is from renewable sources [24]. Most of the renewable power is from solar and wind, 42.55% and 32.79% respectively. Renewable power has potential to be the sole sustainable power source of the future due to its free fuel and low environmental impact. But, in order to maintain current quality of life renewable sources need to be more reliable. Solar power exhibits a diurnal pattern which allows solar to be predictable and considered into the day-ahead market for determining the power demand and generation; but solar is unreliable for approximately 50% of every day as the day becomes night and solar power is unavailable. Wind, on the other hand, has no constant pattern and is difficult to predict into the market with variability between seasons. These unreliability issues could cause curtailment of renewable power as it is difficult to predict into the market. Since the RPS is currently low, there is little curtailment [29]. However, with installation of new renewable power plants and increasing RPS there will be larger potential for renewable curtailment [30].

Solar and wind power sources have potential difficulties integrating into the power infrastructure due to the inability to control generation and to match demand. For example, Figure 2 shows the duck curve [31]. The duck curve is a representation of change in net load, electricity demand after renewable generation, with solar power plant installation. The different lines represent different years which accounts for increasing capacity of solar power with time. The duck curve shows a dip in the net demand, due to high solar power penetration, and illustrates the demand needed to be met by non-renewables. As more renewables are installed and implemented the valley will become steeper and steeper, representing a duck shape. Solar peaks during the day, around 12:00pm, which does not coincide with the peak demand which is around 8:00pm. This sudden change from lowest to highest net load will require ramping power plants which are more inefficient and have worse emissions than base load power plants. The rapid ramp would be detrimental to the electric grid both to equipment operation and emissions which may result in the curtailment of renewable power due to ramping limitations of generation technologies.

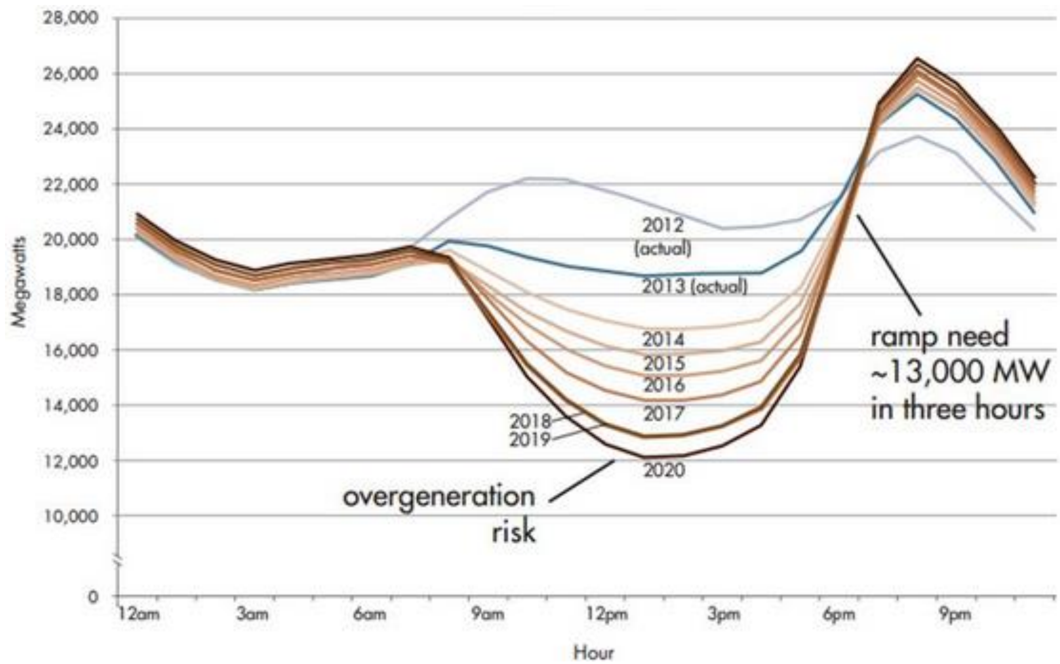

Figure 2: A representation of net load within a day as the installation capacity of solar power increases with time, known commonly as the duck curve. It can be seen that as the years increase from 2012 to 2020 the net load decreases due to increased capacity of solar which requires extreme ramping after 4pm due to the sun setting.

The complication of solar power can be seen even now. With an example from the solar eclipse on August 21, 2017, data from the California Independent System Operator shows a sudden decrease in solar power, seen in Figure 3 [32]. Solar power decreases around 9:00 am, the beginning of the solar eclipse, and a sudden increase around 11:00 am which marked the end of the solar eclipse. This sudden change in solar power increase required a large curtailment of solar power, about 1 GWh of power had to be curtailed due to oversupply after the solar eclipse ended [33]. This trend is abnormal, as a solar eclipse is rare, but it is a natural phenomenon which will happen and will have a significant effect if the electricity system is highly solar dependent.

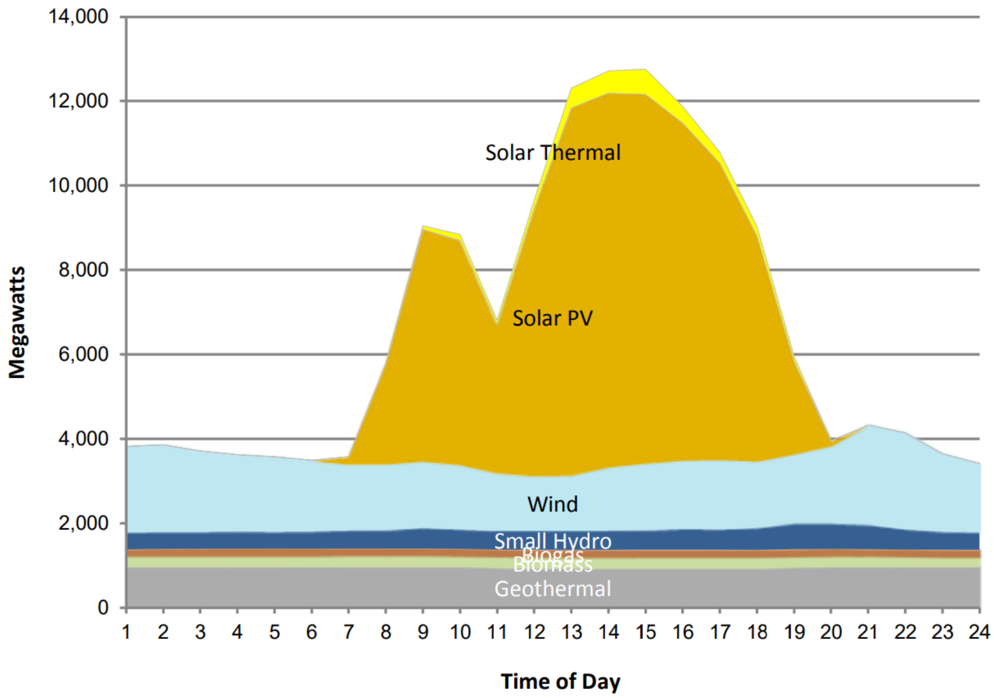

Figure 3: The graph shows the production of various types of renewable generation throughout the day of August 21, 2017. There is a sudden dip followed by a sudden increase in solar PV generation due to the solar eclipse.

2.3.1 Renewable Power

Solar power is a large contributor for the duck curve, since it can only be produced during the day [30]. Energy storage is required in order to have higher penetration of solar power as the generation does not sync with the demand. Wind also has high potential as a renewable power source due to its relatively cheap price. The Energy Information Administration predicts the levelized cost of electricity for wind to be $43.3/MWh and for solar to be $61.2/MWh in 2022 [34]. The cost of wind power is 20% lower than the cost of solar power.

Wind power output does not always match the fluctuations in power demand that typically peak in the afternoon hours and are lowest at night [35]. Large amounts of wind energy are curtailed due to overproduction of energy. At night when winds are high and loads are low, non-renewable power plants need to run at minimum generation which results in the curtailment of wind power plants to balance the load [36]. Large amounts of wind power will cause an increase in intermittency in the electricity system and market [37]. Wind intermittency is due to: transmission congestions, insufficient transmission availability, minimum operating levels, avoid high penetrations or back-feeding, need to maintain frequency requirements and stability issues [36]. This will require greater flexibility of the power system to maintain stability. Utilizing wind energy to maximum potential can be accomplished through energy storage.

It’s difficult to store power in large-scale renewable energy, and many high energy storage batteries are expensive [38]. Water or air are the most economical energy storage systems, however they are geologically limited and take time to react. A possible energy storage pathway is to produce hydrogen with renewable power. Hydrogen is currently mostly produced from carbon based fuels which emit harmful pollutants and GHGs. In order to fully implement hydrogen production from renewable power, a complete economic analysis and an understanding of renewable power generation must be understood. The economics depends on renewable power availability, cost of the individual components (electrolyzers, hydrogen storage, and fuel cells), dynamics of use and utilization factors, and cost of competitive technologies.

Studies have considered using wind power and electrolysis to produce hydrogen. A case study for the Fars province in Iran determined the capacity of wind by recording wind speed and direction for a year, no economic analysis was conducted [39]. A Weibull distribution was used in order to determine the wind capacity. A paper from the University of California, Irvine states that wind speed and direction does not directly correlate to the amount of power generated [40]. The electrical power output from wind turbines is limited by instantaneous wind availability, with only a few minutes of electric power stored within the turbine rotational inertia. So, it is important to understand how wind power is generated through a spatial and temporal analysis.

2.4 Energy Storage

Different technologies can be used to store otherwise curtailed power. Each technology has benefits and drawbacks regarding the time frame of discharge and power rating. This thesis will primarily focus on electric (battery) and gas (hydrogen and methane) energy storage.

2.4.1 Batteries

Batteries have been used to store electricity for devices, transportation, and stationary energy storage. Although, batteries tend to have limited durability and high maintenance requirements [35]. Even though Lithium-ion (Li-ion) batteries are commonly used in smartphones and even in the Tesla electric car, Li-ion batteries have potential environmental and health impacts in electronic waste [41]. Flow batteries circulate reactants to prevent the electrodes from participating in the reaction, preventing the fast degradation seen in conventional batteries [35]. This also allows system power and energy capacity to be independent from each other. The different discharge time and power ratings of battery energy storage technologies are limited by storage to the order of hours [42]. This shows that the battery systems are limited to daily storage as opposed to seasonal storage.

2.4.1.1 Electric Vehicles

Batteries for energy storage could also be accomplished through EV charging. EVs have the potential of reducing emissions in the Transportation Sector as well as intake otherwise curtailed renewable power from the electric grid. But, EVs have the concerns of impacting the load demand profile as well as charging time. A study found that with drivers charging in the early evening immediately when returning home from work the RPS only reached up to 56.7% despite having enough renewables to reach 87% [43]. The time of charging EVs do not match with renewable power generation. Most drivers would like to charge after coming home from work which is also when the sun starts to set and solar power is low. In the same study, if smart charging, which allows the electric grid to optimize based on cost function of net load, is applied the RPS can increase to 73%. The study also included vehicle-to-grid charging, which the electric grid can both charge to and discharge from the EV, is able to increase the RPS to 84%. Only by optimizing EV charging to work in favor the grid can the RPS reach high values. This will require cooperation with the vehicle owners and a change in driving/charging patterns in order to accomplish maximum renewable integration.

2.4.2 Hydrogen

Hydrogen has the potential of using otherwise curtailed electricity to produce energy storage from electrolysis [35]. The hydrogen produced has different use cases. It can be used to replace natural gas or fuel for vehicles or it can be used to store and produce electricity. Each pathway is able to meet different energy demands and offset CO_2 emitting technologies.

2.4.2.1 Production and Usage

Hydrogen can be produced from different sources: water, biomass, natural gas, or coal. Currently, hydrogen is mainly produced from natural gas via steam methane reforming [44]. Steam methane reformation has three key reactions, seen in Equations 1 through 3 [45]:

$$CH_4 + H_2O \Leftrightarrow CO + 3H_2 \tag{1}$$

$$CH_4 + 2H_2O \Leftrightarrow CO_2 + 4H_2 \tag{2}$$

$$CO + H_2O \Leftrightarrow CO_2 + H_2 \tag{3}$$

These reactions produce carbon monoxide (CO), carbon dioxide (CO_2), and hydrogen (H_2). Steam methane reforming is the most used process due to the low operating temperature, best H_2/CO ratio, no oxygen requirement, and having the most developed industrial process [46]. Although it is the best option with low price and production simplicity, it produces harmful emissions CO and CO_2.

A renewable and cleaner alternative for hydrogen production is through electrolysis. Electrolysis only requires water, and does not emit CO_2 due to lack of carbon present in the reaction. The basic process of electrolysis is fairly simple [47]. Two electrodes, which are attached to an electricity source, are submerged in water. Electricity runs through the electrodes to produce hydrogen at the cathode and oxygen at the anode. The oxygen could be captured for sale or vented directly into the atmosphere since oxygen is not harmful to the environment or humans [48]. The only resources required for electrolysis are electricity and water. The water is considered renewable since water is consumed while producing hydrogen and water is produced when using hydrogen as an energy source, seen in the reaction in Equation 4, an overall net zero consumption of water.

$$2H_2O + \text{electricity} \Leftrightarrow O_2 + 2H_2 \tag{4}$$

The main disadvantage to electrolysis is the amount of electricity needed which is currently approximately 65 – 85.7kWh/kg H_2, although the values used in this thesis are future, more efficient power intensities of around 35 – 50 kWh/kg H_2 [49].

The current cost of hydrogen, produced by central grid electrolysis, is approximately $4.50/kg, not including delivery, compression, storage, or dispensing costs [50]. A study conducted on the cost of hydrogen through wind powered electrolysis found a range of $3.72/kg to $12.16/kg, depending on the cost of wind electricity [51]. NREL conducted this study by averaging wind data; a detailed analysis of an individual site with yearly variation was not included. This study did not focus on harnessing curtailed wind to power electrolysis to help stabilize the electric grid. Another study has also been conducted on economic analyses of hydrogen production using electricity generated with the wind turbine system in Kirklareli, Turkey [52]. This study found a hydrogen cost range from $0.35/kg to $4.49/kg of hydrogen. The range varied dependent on the hub height of the wind turbines. As seen by these studies there are many different ranges of potential hydrogen costs, depending on different parameters. This suggests that an independent study on a specific location is required in order to determine the true costs of producing hydrogen through wind powered electrolysis.

Hydrogen can be used in many different industries, so an overproduction of hydrogen is not an issue [53]. Hydrogen would be a useful energy source and can be used through many different pathways [54]. The three main destinations for the curtailed power produced hydrogen are: the natural gas grid, the electric grid, and fuel for vehicles.

2.4.2.2 Power to Gas

Power to Gas (P2G) represents an idea of which excess, otherwise curtailed power could be utilized to produce hydrogen gas through electrolysis. The hydrogen gas produced can be used in many different use cases with different benefits and challenges.

Offsetting Natural Gas

Renewable hydrogen could be directly injected into the natural gas pipeline or run through methanation to produce methane. Since the hydrogen is produced solely from renewable power the gas is renewable and sustainable which can reduce emissions in the natural gas system. Currently a research project at the University of California, Irvine demonstrates injection of hydrogen into an already existing natural gas power plant [55]. The project has proven successful and shows that hydrogen injection is possible with little change to current infrastructure. Although, one problem with hydrogen injection is the limitation of hydrogen volume in natural gas for power plant engine and equipment. One study found that exceeding a 20% volumetric fraction blend with natural gas displays an exponential increase in burning velocity [56]. The study suggests that the optimum hydrogen volumetric fraction be around 20% to achieve the best compromise in engine performance and emissions. So, it will be imperative to not exceed volumetric fractions greater than 20% of hydrogen injection into the natural gas system.

In cases where hydrogen injection is greater than 20%, the production of renewable methane may be more favorable. The production of methane requires an extra step of methanation which results in a loss of efficiency. But, methane may be easier to transport as the natural gas infrastructure is mostly composed of methane and is not limited by volume percent. The reaction for hydrogen undergoing methanation can be seen in Equations 5 to 6.

$$3H_2 + CO \rightarrow CH_4 + H_2O \tag{5}$$

$$4H_2 + CO_2 \rightarrow CH_4 + 2H_2O \tag{6}$$

Hydrogen is reacted with CO_2 in order to produce methane, renewable methane. This can help reduce carbon emissions into the atmosphere. CO and CO_2 are emitted during combustion of CH_4; but the CO and CO_2 can be captured to react with hydrogen in order to production CH_4 through methanation, resulting in a net zero emission of carbon.

Fuel Cell Vehicles

A solution to reducing CO_2 emissions in Transportation Sector is to use alternative fuel such as electricity or hydrogen. Like EVs, FCVs have zero tail pipe emissions. FCVs include a fuel cell which will combine the hydrogen and oxygen to form water and produce electricity, environmentally benign products. FCVs will require fueling from hydrogen stored at fueling stations, similar to pumping gas for gasoline vehicles. Not only do FCVs offer a familiarity in refueling, it also allows for the mismatch between fueling and fuel production, unlike EVs which require electricity to be produced while the EVs are charging and add extra load.

The Advanced Power and Energy Program (APEP) at the University of California has studied a successful public hydrogen station and continues to work on implementing more fueling stations, promoting the usage of FCV [57]. FCVs and EVs are becoming more widely used as they have less of an environmental impact compared to combustion engines. APEP also have white papers which show that both EVs and FCVs have the potential of lower GHG emissions than gasoline vehicles [58] & [59]. The EVs have higher efficiencies and lower emissions. But, FCVs have longer ranges and faster fueling than EVs. A mixture of an EV and a FCV, plug in fuel cell vehicle (PFCV), results in a mixture of high range and low emissions combing the benefits of both technologies. This thesis will not go over PFCVs and will instead focus on the individual technologies.

Stationary Fuel Cells

Another prospect of hydrogen usage is in stationary fuel cells to produce electricity for the electric grid. Multiple fuel cell types can utilize either hydrogen or natural gas as fuel. FCVs have polymer electrolyte fuel cells which utilize pure hydrogen; however stationary fuel cells such as molten carbonate or solid oxide fuel cells can run off of natural gas. Currently, the hydrogen supply would not be able to meet the demand of a fuel cell so most stationary fuel cells require natural gas. Once more efficient hydrogen distribution is established, stationary fuel cells could be powered by hydrogen instead of natural gas.

The optimal location for energy production is near the loads it must supply to. Most of the wind and solar farms are located far from cities and have to travel long distances. Electricity must travel immediately after generation to the load and travels through unappealing electric lines. On the other hand, gas may be used at any time and the distribution methods are hidden. Hydrogen has less energy losses traveling through pipelines and can be stored [60]. Previous APEP graduate student Peter Willette conducted a study on three potential delivery scenarios: gaseous hydrogen via pipeline, gaseous hydrogen via truck distribution, or liquid hydrogen via truck distribution [61]. He was able to use a modeling tool to determine the amount of piping or trucks needed to deliver hydrogen. It was found that installing a new pipeline for hydrogen would be more expensive than using trucks, but a detailed economic analysis would need to be conducted in order to verify.

2.4.2.3 Safety

A large concern of relying on a hydrogen infrastructure stems from fear of hydrogen safety. From past events, such as the Hindenburg disaster, hydrogen is seen as a highly flammable/explosive element which would be difficult to control and utilize. But, it’s important to look at the specifics of hydrogen relative to the past events. In the Hindenburg disaster, the victims were not killed or injured from the hydrogen burning but rather the flammable debris, smoke inhalation, and jumping from the airship at excessive height [62]. Hydrogen burned quickly and clearly, with no smoke, and lifted up into the air. During a lecture, Professor Jack

Brouwer of University of California, Irvine stated that the survivors had burning hydrogen swirling around them as they floated to the ground, but were able to land safely [63].

Most concerns for hydrogen are also concerns for gasoline and natural gas, which we use today. The main differences between these sources of fuel are the densities and flammability limits. Hydrogen has a much wider range of flammability limits than gasoline and natural gas. The lower flammability limit is similar to natural gas and this is the point which causes a leak to ignite. A typical ignition source near a leak or accident would have enough energy to ignite all conventional fuels. Hydrogen has the benefit of having a density less than air. In the event of a leak, hydrogen will float out of harm's way. On the other hand, natural gas and gasoline will stay near the ground and linger close to the scene of the accident [63]. A study conducted by Dr. Swain at the University of Miami shows the differences between an ignited fuel source between hydrogen and gasoline vehicles [64]. The hydrogen rises up and away from the vehicle, with little to no damage to the vehicle; while the fire caused by the gasoline envelopes the vehicle and burns for a longer period of time than the hydrogen. Hydrogen does have safety concerns, similar to all fuel types, but it has a very large potential to lower emissions and could potentially be safer than conventional fuels.

2.5 Summary

Typical studies that have been conducted consider the potential costs for the production of hydrogen without the effects to the electric grid. Stand-alone systems of which an electrolyzer is connected to one technology type, such as wind turbines, as opposed to the entire electricity system are common [52]. While some studies utilize the H2TIMES modeling framework from the Energy Technology Systems Analysis Program focus on renewable and low-carbon hydrogen, they do not model the larger California energy system as a whole [65]. The usage of otherwise curtailed renewable power to produce hydrogen is also not considered in these studies.

The research presented in this thesis addresses economic and system wide effects of utilizing otherwise curtailed renewable power in order to produce hydrogen for energy storage and fuel use cases. The economic considerations in this thesis span different technology types, pathways, and use cases. The consideration of the entire California electric grid also allows consideration of the manner by which the hydrogen production pathways could influence the renewable portfolio standard, costs of energy, and greenhouse gas emissions. Simply stated, this thesis addresses the entire energy system in order to evaluate the potential effects of hydrogen production on the electricity system, and the emission of greenhouse gases.

3 Approach

Task 1: Determine the Potentials of Hydrogen as an Energy Carrier

Use HiGRID to run tests on different energy and power capacity to see how fuel cell vehicles and hydrogen storage would have on the California energy system. This will determine the potentials of hydrogen as an energy carrier on the electric grid.

Task 2: Compare Costs of Different Pathways to Determine Effectiveness on the Grid

The economics and costs of different hydrogen pathways will be run in HiGRID in order to compare costs and effects on the grid. The different pathways use renewable power for P2G and battery energy storage. There will be multiple scenarios to understand the different operation methods and how it will influence cost and the grid.

Task 3: Understand the Environmental Effects of Each Technology and Pathway

Each pathway will have different amount of GHG emissions. It's important to not only understand the economics of technologies but also the environmental impacts. The operations of each pathway will have a different effect on the grid which results in different CO_2 emissions.

4 Methodology

This project will examine three different P2G applications which can provide benefits for the electric grid: producing renewable gas to be injected into the natural gas (NG) pipeline to offset conventional natural gas use, producing hydrogen (H_2) to fueling vehicles, and producing renewable gas as energy storage (ES) for electricity to the grid. Each use case will utilize a different mix of equipment, detailed in Table 1. The required equipment for the different use cases are electrolyzer (ELY), methanator (METH), fuel dispensing equipment (FUEL), fuel cell (FC), hydrogen energy storage (HES), and battery energy storage (BES). These different use cases will be considered independently to understand the effects of each use case implemented onto the California energy system. A visualization of the pathway can be seen in Figure 4. The red numbers correlate to each use case.

Table 1: Required equipment for each use case.

#	Description of Use Case	Required Equipment for Each Use Case					
		ELY	METH	FUEL	FC	HES	BES
1	H_2 into NG Distribution System	X					
2	H_2 into NG Transmission System	X					
3	CH_4 into NG Distribution System	X	X				
4	CH_4 into NG Transmission System	X	X				
5	Gaseous H_2 Trucked to H_2 Fueling Station	X		X			
6	Liquid H_2 Trucked to H_2 Fueling Station	X		X			
7	Onsite Gaseous H_2 at H_2 Fueling Station	X		X			
8	H_2 into Fuel Cell; Electricity to Grid	X			X	X	
9	Battery Charge/Discharge to Grid						X

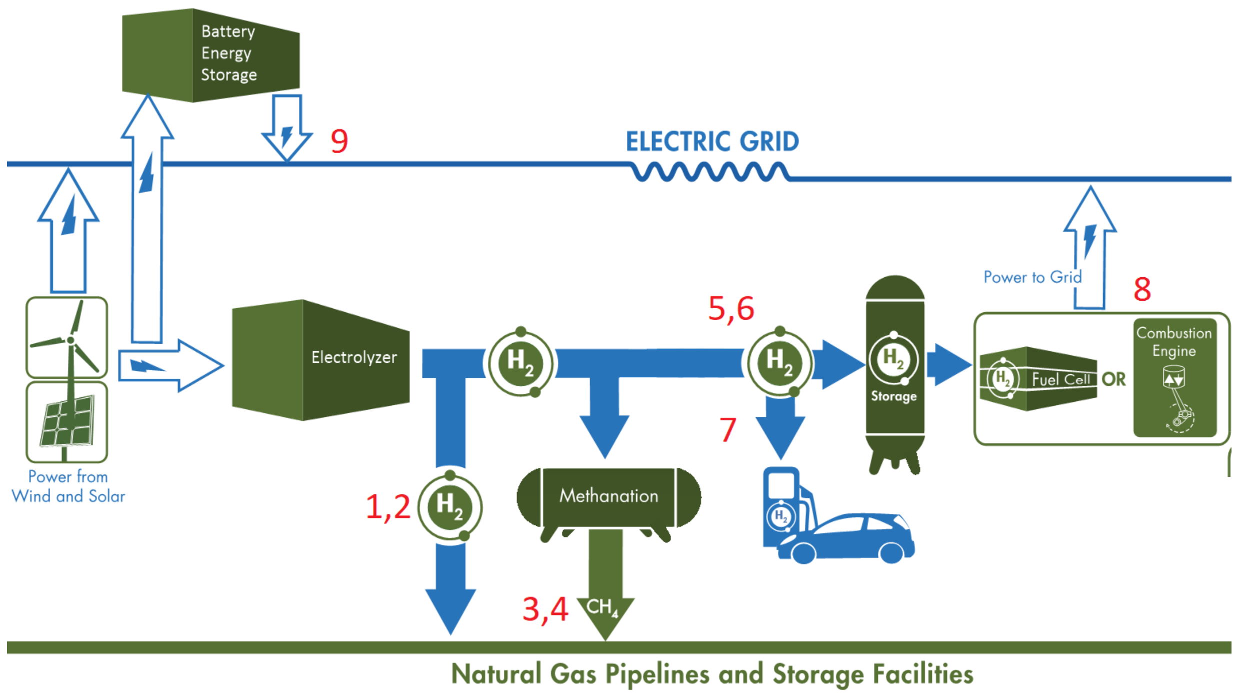

Figure 4: An overall view of the different use cases, labeled in red text correlating to Table 1. There are 9 different use cases but only three destinations: replacement of NG in the NG pipelines, fuel for FCVs, and electricity in order to balance the electric grid.

As seen in Figure 4, all pathways begin with power from otherwise curtailed renewable sources, most commonly wind and solar power. For all pathways 1 to 8 the electricity will run through an electrolyzer to produce hydrogen. The produced hydrogen travels to different end uses. Use cases 1 to 4 help offset natural gas. For use cases 1 and 2, hydrogen is injected directly into the natural gas either through the distribution or transmission system. For use cases 3 and 4, the hydrogen is run through a methanator in order to produce renewable methane which will also be input to the natural gas pipeline through distribution or transmission system. Use cases 5 to 7 produce hydrogen for fueling hydrogen fuel cell vehicles. The hydrogen could be produced offsite and transported in gaseous, use case 5, or liquid form, use case 6; or hydrogen could be produced directly onsite, use case 7. Lastly, for use case 8, the produced hydrogen is stored and later ran through a fuel cell to produce zero emission electricity for the grid. Battery pathways, use case 9, will collect electricity straight from the renewable sources and store it for later use.

The different technologies considered are detailed in Table 2. The solid oxide electrolyzer uses heat to help offset the electricity requirements, resulting in a heat rate less than 1. The heat is assumed to be free excess waste heat from peaker and load following power plants or industrial processes. All other electrolyzer technologies rely only on electricity as energy input.

Table 2: The different technologies considered for the use cases and pathways.

Electrolyzer Cell Technologies	Fuel Cell Technologies	Battery Energy Storage Technologies
Alkaline (AEC)	Phosphoric Acid (PAFC)	Zinc-Bromide Flow (ZnBr)
Solid Oxide (SOEC)	Solid Oxide (SOFC)	Lithium-Ion (Li-ion)
PEM (PEMEC)	PEM (PEMFC)	Advanced Lead Acid (Lead Acid)
	Molten Carbonate (MCFC)	Sodium-Sulfur (NaS)

Each use case has a mix of different technologies, resulting in 37 different pathways listed below. The pathways are separated based on use case.

Use case 1:

1. Alkaline Electrolyzer H_2 Injected into Distribution System
2. Solid Oxide Electrolyzer H_2 Injected into Distribution System
3. PEM Electrolyzer H_2 Injected into Distribution System

Use case 2:

4. Alkaline Electrolyzer H_2 Injected into Transmission Pipeline
5. Solid Oxide Electrolyzer H_2 Injected into Transmission Pipeline
6. PEM Electrolyzer H_2 Injected into Transmission Pipeline

Use case 3:

7. Alkaline Electrolyzer H_2 to Methanator; CH_4 Injected into Distribution System
8. Solid Oxide Electrolyzer H_2 to Methanator; CH_4 Injected into Distribution System
9. PEM Electrolyzer H_2 to Methanator; CH_4 Injected into Distribution System

Use case 4:

10. Alkaline Electrolyzer H_2 to Methanator; CH_4 Injected into Transmission Pipeline
11. Solid Oxide Electrolyzer H_2 to Methanator; CH_4 Injected into Transmission Pipeline
12. PEM Electrolyzer H_2 to Methanator; CH_4 Injected into Transmission Pipeline

Use cases 5:

13. Alkaline Central Plant Electrolyzer; Gaseous H_2 Trucked to H_2 Fueling Station
14. Solid Oxide Central Plant Electrolyzer; Gaseous H_2 Trucked to H_2 Fueling Station
15. PEM Central Plant Electrolyzer; Gaseous H_2 Trucked to H_2 Fueling Station

Use case 6:

16. Alkaline Central Plant Electrolyzer; Liquid H_2 Trucked to H_2 Fueling Station
17. Solid Oxide Central Plant Electrolyzer; Liquid H_2 Trucked to H_2 Fueling Station
18. PEM Central Plant Electrolyzer; Liquid H_2 Trucked to H_2 Fueling Station

Use case 7:

19. Alkaline Onsite Electrolyzer; Gaseous H_2 Generated at H_2 Fueling Station
20. Solid Oxide Onsite Electrolyzer; Gaseous H_2 Generated at H_2 Fueling Station
21. PEM Onsite Electrolyzer; Gaseous H_2 Generated at H_2 Fueling Station

Use case 8:

22. Alkaline Electrolyzer H_2 into PEM Fuel Cell; MWh Delivered into Electric Grid
23. Solid Oxide Electrolyzer H_2 into PEM Fuel Cell; MWh Delivered into Electric Grid

24. PEM Electrolyzer H_2 into PEM Fuel Cell; MWh Delivered into Electric Grid
25. Alkaline Electrolyzer H_2 into PAFC Fuel Cell; MWh Delivered into Electric Grid
26. Solid Oxide Electrolyzer H_2 into PAFC Fuel Cell; MWh Delivered into Electric Grid
27. PEM Electrolyzer H_2 into PAFC Fuel Cell; MWh Delivered into Electric Grid
28. Alkaline Electrolyzer H_2 into MCFC Fuel Cell; MWh Delivered into Electric Grid
29. Solid Oxide Electrolyzer H_2 into MCFC Fuel Cell; MWh Delivered into Electric Grid
30. PEM Electrolyzer H_2 into MCFC Fuel Cell; MWh Delivered into Electric Grid
31. Alkaline Electrolyzer H_2 into SOFC Fuel Cell; MWh Delivered into Electric Grid
32. Solid Oxide Electrolyzer H_2 into SOFC Fuel Cell; MWh Delivered into Electric Grid
33. PEM Electrolyzer H_2 into SOFC Fuel Cell; MWh Delivered into Electric Grid

Use case 9:

34. ZnBr Flow Battery
35. Li-Ion Battery
36. Advanced Lead-Acid Battery
37. Sodium-Sulfur Battery

4.1 HiGRID

In order to determine the economics and effects of energy storage technologies on the California electric grid, the Holistic Grid Resource Integration and Development (HiGRID) Tool was used. HiGRID is able to simulate the operation of the California grid over a year with hourly resolution. For a simplified explanation of HiGRID: HiGRID is composed of four large modules Renewable Generation Module, Dispatchable Load Module, Balance Generation Module, and Cost of Generation Module. The modules are operate in order from least flexible to most flexible. The Renewable Generation Module takes the installation capacity of different renewable technologies, such as solar and wind, and outputs a vector of hourly power generation. Then, with an estimated load based on the year and population, a net load is determined in order to be used in the Dispatchable Load Module. The Dispatchable Load Module captures the effect of technologies which can modify the net load profile, such as Demand Response, Energy Storage, and Transportation Modules. Two modules are particular to the different use cases considered in this report. The Energy Storage (ES) Module is for use cases 8 and 9; the Hydrogen Electrolysis Dispatch (HED) Module is for use cases 1 to 7. The Balance Generation Module works to dispatch balancing power plants to balance the remainder of the load after the Dispatchable Load Module. Lastly, the Cost of Generation Module uses the operational results from the other modules to determine the cost of energy for each technology type on the grid.

4.1.1 Energy Storage Module

The ES module works to smooth the net load profile by charging installed energy storage systems during times of low net load and discharge these systems during times of high net load, fill valleys and shave peaks. This helps alleviate the variability of renewable power and stabilize the grid. A visual representation of smoothing the net load can be seen in Figure 5. The black line represents the net load without energy storage and the red line represents the net load with energy storage. It can be seen that the peaks are lower in the red line due to charging during low net loads, which result in the valleys rising.

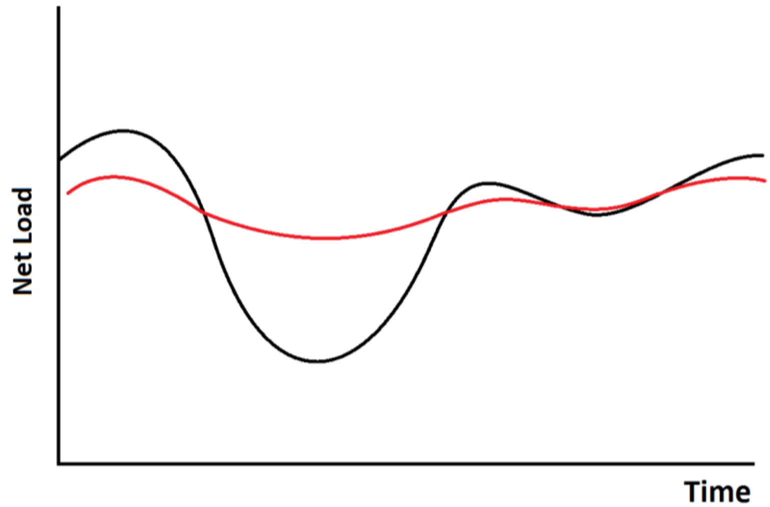

Figure 5: A representation of smoothing out the net load by capturing otherwise curtailed power to decrease peaks in net demand. The red line represents a smoother net load from storing electricity during times of low net load to use during high net load. The black line represents the net load without ES.

The ES module requires inputs for energy capacity as well as power capacity. Two cases are considered. The first case allows full utilization of the otherwise curtailed power, the power capacity is set to the maximum power of the otherwise curtailed power. This will benefit the grid to take in all the otherwise curtailed renewable power. The second case, in order to increase the capacity factor, has a limitation on power capacity. The limitation lessens the effects of stabilizing the grid from a system wide perspective, but with the benefits of limiting the levelized costs of energy. Since energy storage is meant to offset demand that cannot be met by renewable power, the limitation was set to the power capacity of the load followers and peaking power plants from the base case run.

The differences between use cases 8 and 9 are efficiency and energy capacity. The efficiency is based on the round trip, how much electricity is discharged based on how much is charged. The energy capacity is based off of the hours of storage. For batteries, use case 9, a rated discharge time of 8 hours was chosen due to the limitation of battery technologies in providing long duration storage, but also to allow sustainable peak load shaving [66]. Hydrogen ES, use case 8, was limited at 2190 hours (calculated from total hours in a year divided by 4 for seasonal storage), under the assumption that hydrogen can leverage the natural gas infrastructure as a storage medium. Hydrogen fuel cell systems are considered more suitable for longer-term [7].

4.1.2 Hydrogen Electrolysis Dispatch Module

The goal of the HED module is to dispatch electrolyzer units such that their electric loads are imposed on the grid when the net load is low to provide a valley-filling function. In use cases 1, 2, and 5 – 7, hydrogen is produced and in use cases 3 and 4 methane is produced. The only difference between renewable hydrogen and methane seen by the electric grid is a lower efficiency for producing methane due to an extra step required for methanation. The difference between each use case is the method of distribution and end use.

The HED module requires an input of hydrogen demand. The hourly hydrogen demand in HiGRID is determined based on the hourly vehicles miles traveled. The miles traveled are then converted to kg of hydrogen. Then, a percentage of vehicles which are FCVs are determined. The percent of hydrogen vehicles, in other words, the FCV penetration is dependent on the availability of renewable energy which is calculated from the equivalent base case curtailed renewable power in the system, ensuring the hydrogen demand is not greater than the amount of otherwise curtailed power available. The FCV penetration is determined with Equations 7 and 8.

$$\text{total } H_2 \text{ electric demand (MWh)} = \frac{\text{total hydrogen demand (kg)} * \text{electrolyzer conversion } \left(\frac{\text{kWh}}{\text{kg}}\right)}{1000 \frac{\text{kWh}}{\text{MWh}}} \quad (7)$$

$$\text{FCVpen} = \frac{\text{electrolyzer efficiency} \left(\frac{\text{MWhin}}{\text{MWhout}}\right) * \text{curtailed energy (MWh)}}{\text{total } H_2 \text{ electric demand (MWh)}} \quad (8)$$

The purpose of having the FCV penetration calculated from the base case is to allow for adjustments of the base case in terms of the renewable mix and the electrolyzer technology. Each electrolyzer has a different efficiency in the conversion of electricity to hydrogen. Therefore, each electrolyzer will have a different effect on the electric grid and should be rated to allow for maximum usage of the curtailed power from the initial case.

HiGRID determines when to produce hydrogen based on the lowest cost of electricity which is synonymous to the lowest net load. The model works to smooth out the net load but in turns sets the power capacity of the electrolyzer too high, reducing the capacity factor, by capturing all the curtailed power. Thus, similar to the ES module case, a limitation can be induced on the electrolyzer to help increase the capacity factor and reduce the cost of energy from the electrolyzers. The electrolyzer power capacity is set to match the ES power capacity in order to ensure a fair comparison across all technologies.

The following steps will help demonstrate how the Hydrogen Electrolysis Dispatch Module functions and how the limitation is imposed. Note: the figures are representations of how the curves may look and do not contain real data.

1. The module first looks at the hydrogen demand and the amount of hydrogen stored. Figure 6 below shows the amount of hydrogen stored at any time of the year. The hydrogen demand is imposed on the amount of hydrogen stored, inducing a drop in hydrogen stored over time. The module determines when the hydrogen storage is last full and when it is next empty.

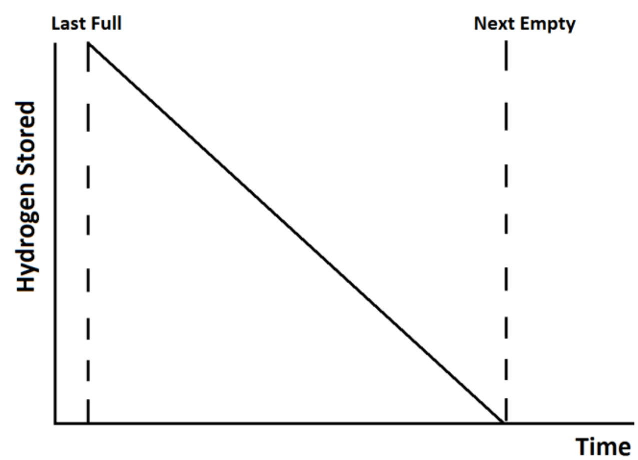

Figure 6: Representation of hydrogen demand on hydrogen stored over time in the HiGRID model.

2. The module then needs to decide when to produce more hydrogen which is at the lowest net load within the “last full” and “next empty” section, as seen in Figure 7. The amount of hydrogen stored increases and shifts the “next empty” point to a point later in time. This allows the module to run through the whole year until the “new empty” point is at the end of the year and there is no longer a hydrogen demand.

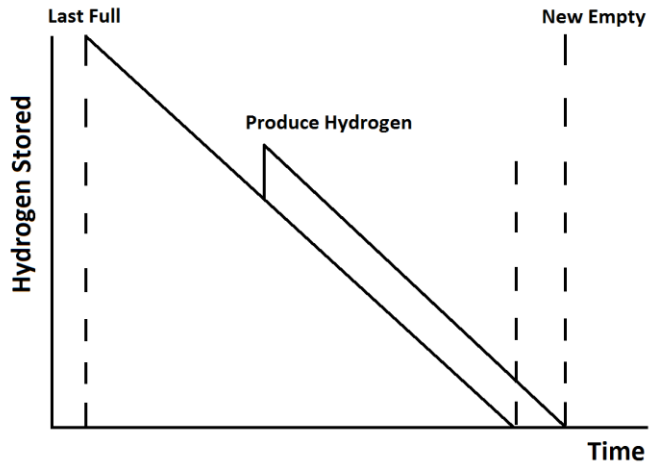

Figure 7: Representation of producing hydrogen and increasing the amount of hydrogen stored over time in the HiGRID model. HiGRID continues to produce hydrogen until the “new empty” reaches the end of the year.

3. The module produces hydrogen at the lowest points in the net load. Figure 8 represents a net load with a large valley without any load from the electrolyzer.

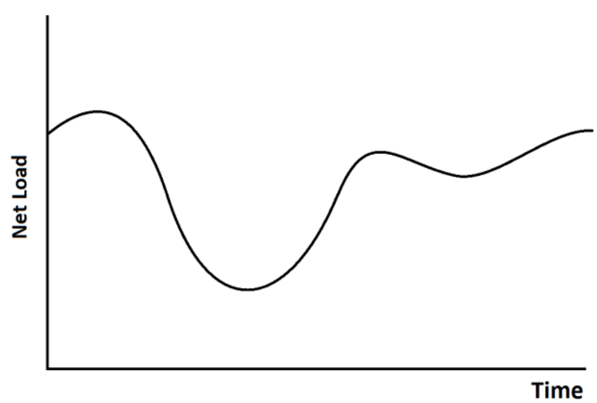

Figure 8: Representation of the net load curve over time.

4. The module will produce hydrogen during the lowest points in the net load, inducing a new load, as seen in Figure 9. The module produces hydrogen and changes the net load in increments until the valley is gone.

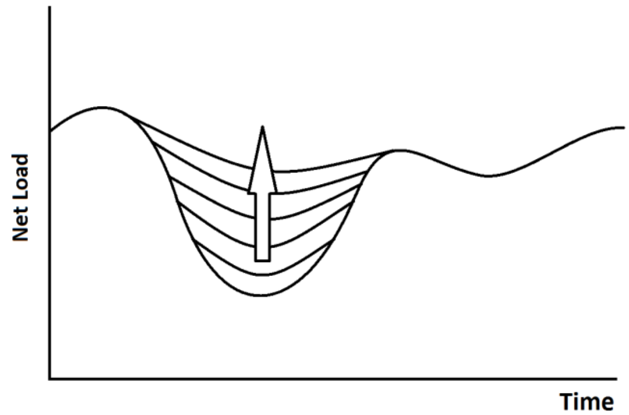

Figure 9: Representation of increasing the net load through the production of hydrogen during low net load.

5. Imposing a limitation prevents the electrolyzer from filling the valley completely and stops it at an increment, seen by the red line in Figure 10.

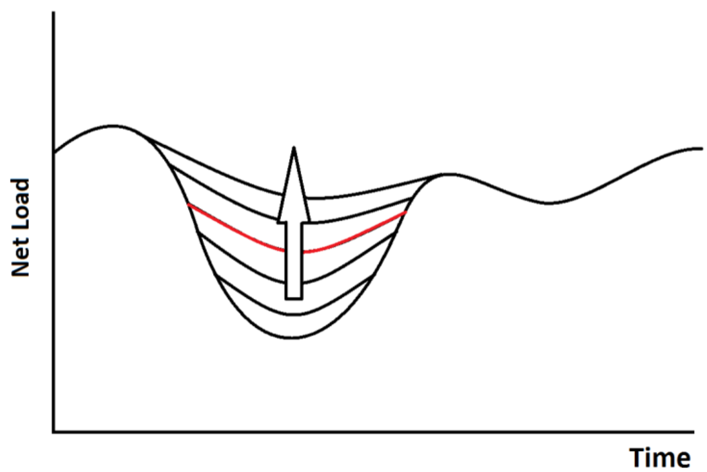

Figure 10: Representation of imposing a limitation on producing hydrogen during low net load, shown by the red line, so the valley is not completely filled as compared to Figure 9.

4.1.3 Potential Effects of Hydrogen Energy Storage

Renewable hydrogen production through electrolysis has the potential to increase RPS to greater than 70% or 80%. Hydrogen, much like a battery, has the versatility of energy storage for the electric grid and fuel for transportation. The HiGRID tool was used to determine the possible RPS with hydrogen energy storage and FCV penetration. The renewable mix seen in Table 3 was used for only the following analysis.

Table 3: Renewable mix for the analysis conducted to understand the potential effects of hydrogen as energy storage.

Renewable Technology	Capacity (GW)
Geothermal	6
Solar Photovoltaic	55
Solar Thermal	55
Wind	31

The following results used both the HED and ES module in order to determine some potential effects of hydrogen storage and FCVs on the electric grid. An analysis found that by spanning the energy and power capacity with a load scaled to population in 2050 and 60% FCV penetration RPS can reach up to 88% as seen in Figure 11. The black line represents a trend of a set energy capacity at 30 GWh with spanning power capacity. It can be seen that as the RPS increases with increasing power capacity until a power capacity of around 3.4 GW, which the RPS then becomes constant. This shows that the energy storage is too small in order to store power at power capacities higher than 3.4 GW. It can also be seen that at every set energy capacity there is a lowest power capacity that results in the highest RPS, represented by the diagonal red line. The red line shows when the energy and power capacity have the best mix in the sense that the power capacity is high enough to capture the excess renewable energy but low enough such that the energy storage is not too small to store the excess renewable energy.

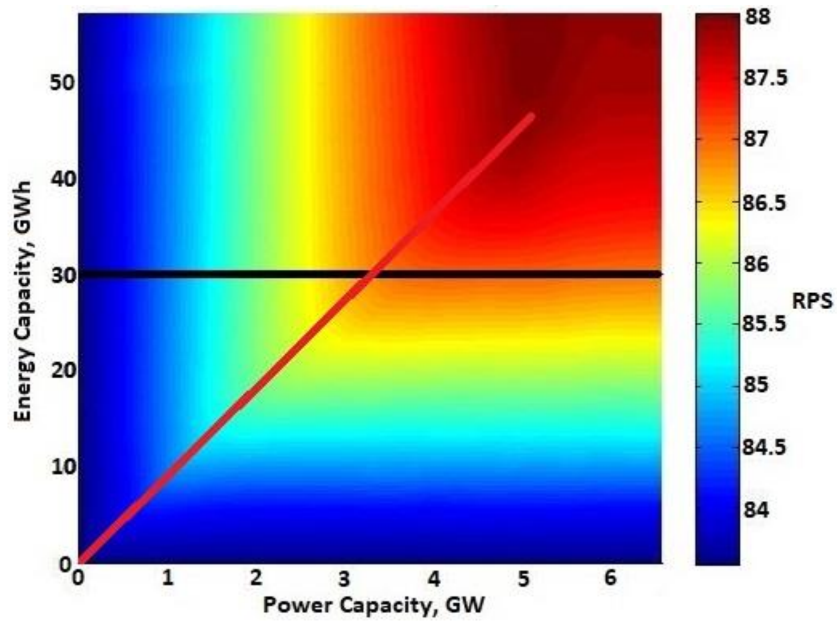

Figure 11: RPS with 60% FCV penetration and scaled to 2050 population with varying power and energy capacity. The color gradient shows lower RPS (blue) to higher RPS (red).

Studying a load scaled to population in 2050 and 80% FCV penetration, the RPS can reach up to around 84% as seen in Figure 12. The black line once again represents a trend of a set energy capacity at 30 GWh with spanning power capacity. The RPS increases with increasing power capacity until a power capacity of around 2 GW. The RPS decreases at higher power capacities due to the amount of excess renewable energy available. Since the power capacity is too high, non-renewables will have to be used in order to store the energy, decreasing the RPS. The red line once again shows the best mix of power and energy capacity. But, the red line reaches higher energy and power capacities in the 60% FCV penetration case than the 80% FCV penetration case. Since more load is imposed by the FCVs there is less available renewable power to be used for energy storage.

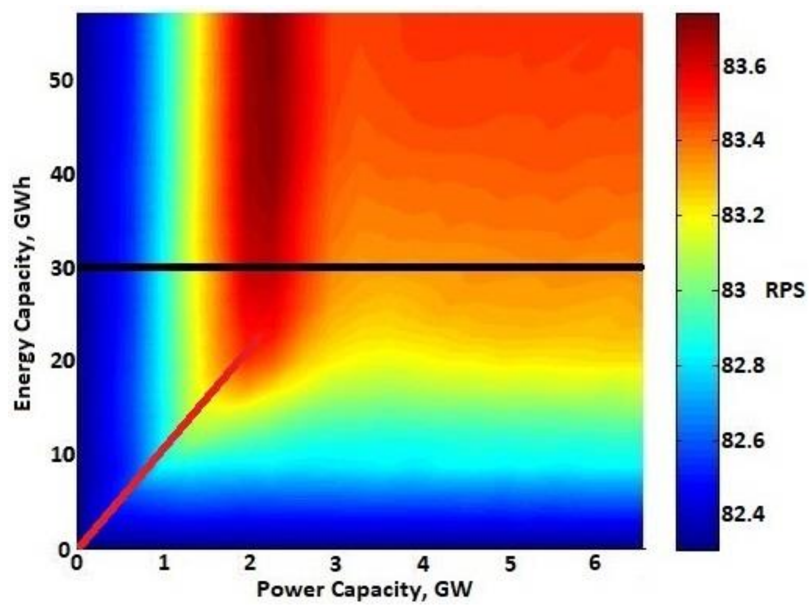

Figure 12: RPS with 80% FCV Penetration and scaled to 2050 population, varying power and energy capacity. The color gradient shows lower RPS (blue) to higher RPS (red).

The highest RPS for the 80% FCV penetration case is only able to reach up to around 83.8% while the maximum RPS achieved in the 60% FCV penetration case was around 88%. This is due to the effects of load from FCVs. The fuel demand for FCVs is not as flexible as energy storage which is why the RPS for the 60% case is higher since it has more potential for energy storage.

4.2 Scenarios

The scenarios considered in this project are for future cases; therefore all cost numbers are future costs. The analysis year is set to be 2050 with a projected load profile and population from the California Department of Finance [67]. Different scenarios were developed in order to fully understand each use case and pathway. The scenarios are described in Table 4.

Table 4: Summary of the different scenarios.

Scenario	Total Capacity	Renewable	Capacity Limitation
1	147 GW		
2	147 GW		X
3	184 GW		
4	184 GW		X

The renewable capacity represents the total amount of installed renewable capacity attempting to reach 70% and 80% RPS with 147 GW and 184 GW respectively; 75% of the total renewable capacity is solar, 21% is wind, and 4% is geothermal. The renewable capacity in scenarios 3 and 4 are 25% higher than in scenarios 1 and 2. In addition, each scenario also includes two different operating modes for dispatchable technologies. In scenarios 1 and 3, the dispatchable technologies are allowed to be sized such that it can capture all of the excess renewable generation. In scenarios 2 and 4, the installed capacity is limited in order to maintain capacity factors above a certain level, such that the costs of these pathways are not excessive. Comparing and contrasting these two cases allows examination of tradeoff between maximum utilization of renewable energy and costs as related to equipment capacity factor.

The capacity limitation determines whether the pathways operate with flexibility to match the grid operations or with less flexibility to increase the pathway's own capacity factor. The methods for how the limitation on capacity is chosen are described in the module explanations (ES Module and HED Module).

Each scenario has an associated base case run. The base case run represents the first run which simulates the California grid under the renewable capacity conditions in order to determine the base case with no use case technologies. This run is used in order to determine the effects of adding the proposed use cases to the grid.

4.2.1 Base Case

In order to run all the scenarios, an initiation file is required in order to establish the base case which will set parameters and initial inputs into HiGRID. A first run of HiGRID with none of the technologies or pathways for energy storage is conducted. The run with HiGRID with no technologies will output data on how much renewables are curtailed and how much power and energy is provided to the load from the load follower and peaker power plants. The base case values for each Renewable Capacity are shown in Table 5.

Table 5: The base case values for CO_2 emissions, LCOE, and RPS.

Total Renewable Capacity	CO2 Emission (MMT/yr)	LCOE ($/GJ)	RPS (%)
147 GW	151.49	70.90	72.5
184 GW	144.02	85.80	77.5

4.3 Economic Assumptions

The economic values[1] are not scaled with power capacity and do not assume differences in initial, fixed, or operational/maintenance costs with different electrolyzer or electrolyzer fleet sizes. The hydrogen storage was assumed to be above-ground pressurized steel tanks; none of the results presented to-date incorporate the option of underground storage. Fueling stations

[1] The economic values used per pathway are based on the results of the Levelized Cost of Energy (LCOE) economic model with future cost assumptions. The methodology and data sources used to develop this model were written by Dr. Lori Schell.

are assumed to have the same economic values as H_2 Injected into Distribution System pathways with an extra cost added separately, seen in Table 6.

Table 6: Extra cost added to hydrogen pathways with end use in a fueling station.

Pathway	Extra cost ($/kg H_2)
Gaseous H_2 trucked to H_2 Fueling Station	1.56
Liquid H_2 trucked to H_2 Fueling Station	1.83
Onsite gaseous H_2 production	2.01

4.4 Calculations

The CO_2 reduction was determined by comparing the amount of CO_2 offset by the introduced technologies to the original run. This CO_2 reduction is only to take into consideration the effects each use case has on reducing CO_2 from one another. It is an approximate and relative calculation and should not be used as a definitive reduction of CO_2 of these technologies. Table 7 shows the calculation for how much CO_2 was offset depending on the use case.

Table 7: Calculation for CO_2 offset.

Use Case	CO_2 calculation
Natural Gas Pipeline Offset (Hydrogen)	# kg H2 * 1000 (g/kg) * 1/453.6 (lb/gram) * 61,000 (Btu/lb H2) * 1/1000000 (MMBtu/Btu) * 0.058 (ton CO2/MMBtu)
Natural Gas Pipeline Offset (Methane)	# kg H2 * (MMBtu CH4/9.55 kgH2) * 0.058 (ton CO2/MMBtu)
Fuel Cell Vehicles	# kg H2 * 54 (mi/kg) * 411 (g/mi) * 1.10231e-6 (ton/g) [68]
Electricity Output	Calculated within HiGRID

The Levelized Cost of Energy (LCOE) was calculated, through Equation 9, as the total economics of each technology over the total energy produced per technology.

$$\text{LCOE}\left(\frac{\$}{\text{GJ}}\right) = \frac{\sum_{\text{All Technolgies}}\left(\text{Levelized Cost of Electricity}\left(\frac{\$}{\text{MWh}}\right) * \text{Total Electricity (MWh)}\right)}{\sum_{\text{Technolgoy}} \text{Total Energy (GJ)}}$$

(9)

Portfolio electricity cost is calculated, seen in Equation 10, with the levelized cost of each electricity producing technology and the total electricity produced per technology. This cost only looks at the technologies which produce electricity to the electric system, so it does not include the P2G or battery use case cost of energy.

$$\text{Portfolio Electrolyzer Feed Cost}\left(\frac{\$}{\text{MWh}}\right) = \frac{\sum_{\text{Electricity Producing Technolgies}}\left(\text{Levelized Cost of Electricity}\left(\frac{\$}{\text{MWh}}\right) * \text{Total Electricity (MWh)}\right)}{\sum_{\text{Electricity Producing Technolgoy}}(\text{Total Electricity (MWh)})}$$

(10)

5 Results

Two different methods of evaluation are considered in this project which represents two different perspectives regarding costs, the system perspective and the investor perspective.

The system perspective examines costs from the perspective of the entire system. From this perspective, the levelized cost of energy in dollars per gigajoule of total energy used by the entire system is the main metric for quantifying costs. This metric represents how energy costs on average change due to the implementation of the different technology sets described previously, but does not provide any insight into the distribution of those costs.

The investor perspective, on the other hand, examines costs from the perspective of the business case for an investor who is looking to deploy the different technology sets in the different use cases. Note that this is distinctly different than the system perspective – in the investor perspective, the primary concern is the business case of investing in these technologies for the investor, which may or may not mirror the trends for system wide costs. The cost of energy is determined by taking the total cost of equipment, distribution, and electricity use over the total energy produced from the pathway. This determines the break-even cost of energy. This report does not determine the price of energy which would be used in the energy market.

In addition to costs, the change in greenhouse gas emissions on a CO_2-equivalent basis from the base case is calculated for each of the technology sets in each of the previously-described use cases. This allows us to determine the cost effectiveness of emissions reductions from both the grid and investor perspectives.

5.1 System perspective - CO_2 versus Levelized Cost of Energy

For the system perspective, CO_2 emissions and the LCOE were used to understand the effects of the different use cases on the electric grid for each scenario. The CO_2 emission sources considered are from the electric grid, and natural gas combustion or from vehicles over a one year period as appropriate for the given use cases. The LCOE change from base is the total LCOE over the total amount of energy in dollars per GJ. Figure 13 to Figure 16 are plotted values of CO_2 and portfolio costs difference from the base case. The difference will be calculated as use case results subtracted from base case results. Therefore, a positive value represents a reduction. The graphs for CO_2 versus LCOE group the pathways into use cases. The individual pathways, technology mixes, are not differentiated by the legend. The set of pathways per use case are closely related in both CO_2 and LCOE. The main focus of this portion of the results will concentrate on the differences between the use cases and the best pathways per use case will be discussed later in the results. Table 8 correlates the legend to the use cases.

Table 8: Correlation between graph legend labels and use cases.

Legend Label	Use Case #
H_2 NG Replacement	1 & 2
Renewable NG	3 & 4
H_2 Fueling	5 & 6
H_2 Fueling Onsite	7
H_2 ES	8
Electric ES	9

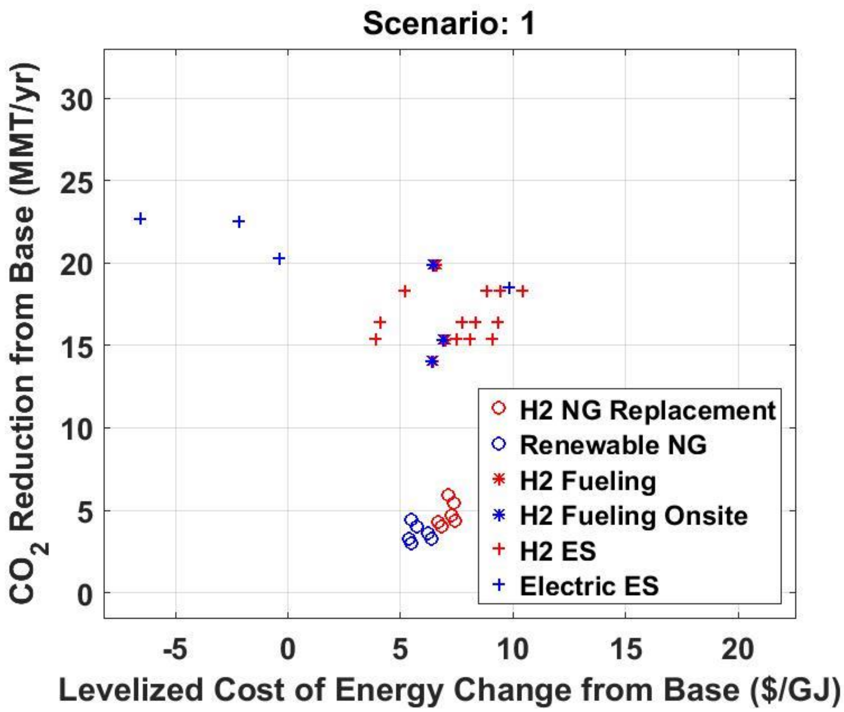

Figure 13: CO_2 reduction versus LCOE change from base case for Scenario 1.

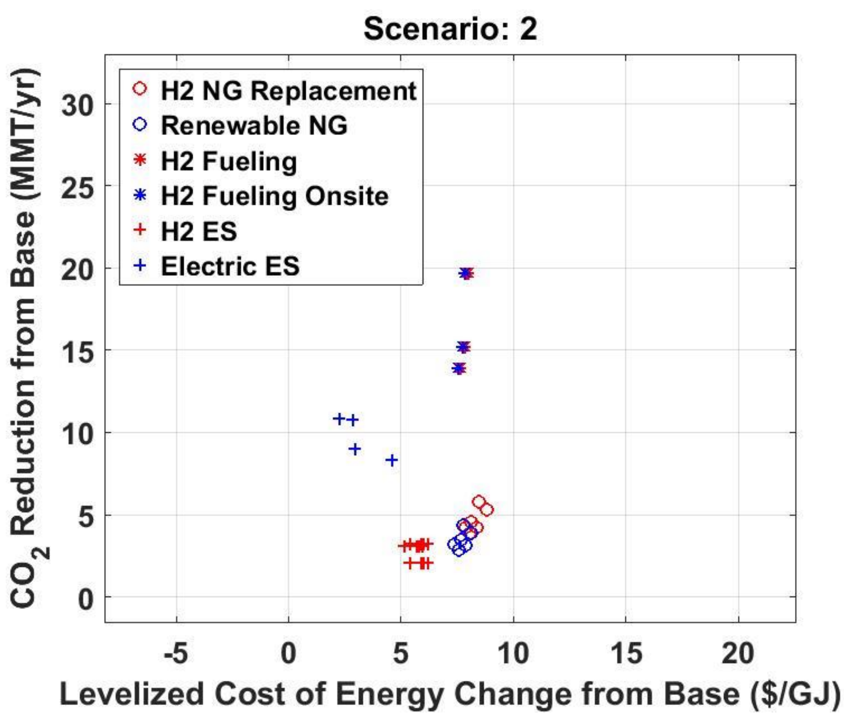

Figure 14: CO_2 Reduction versus LCOE change from base case for Scenario 2.

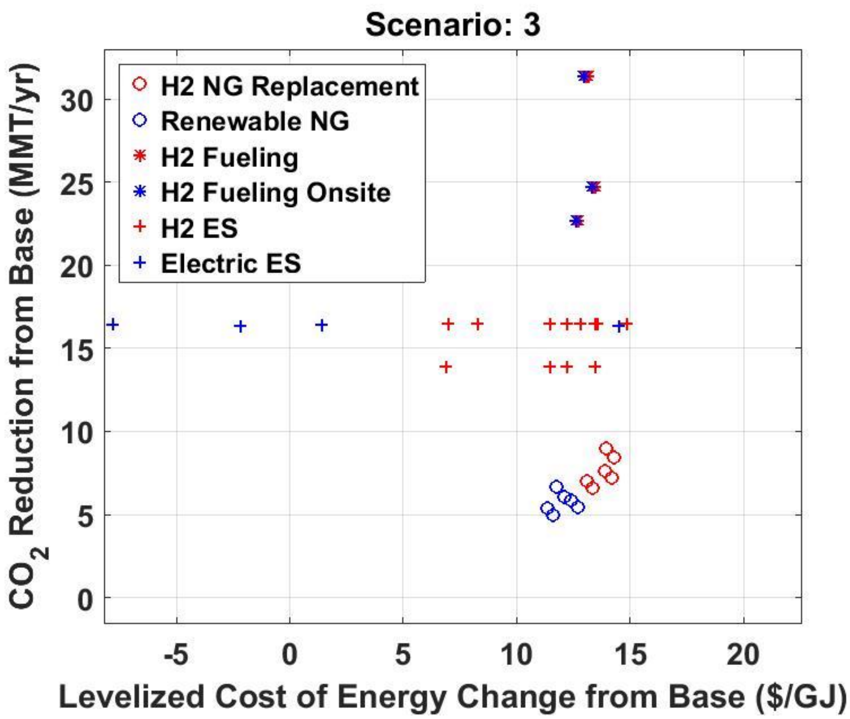

Figure 15: CO_2 Reduction versus LCOE change from base case for Scenario 3.

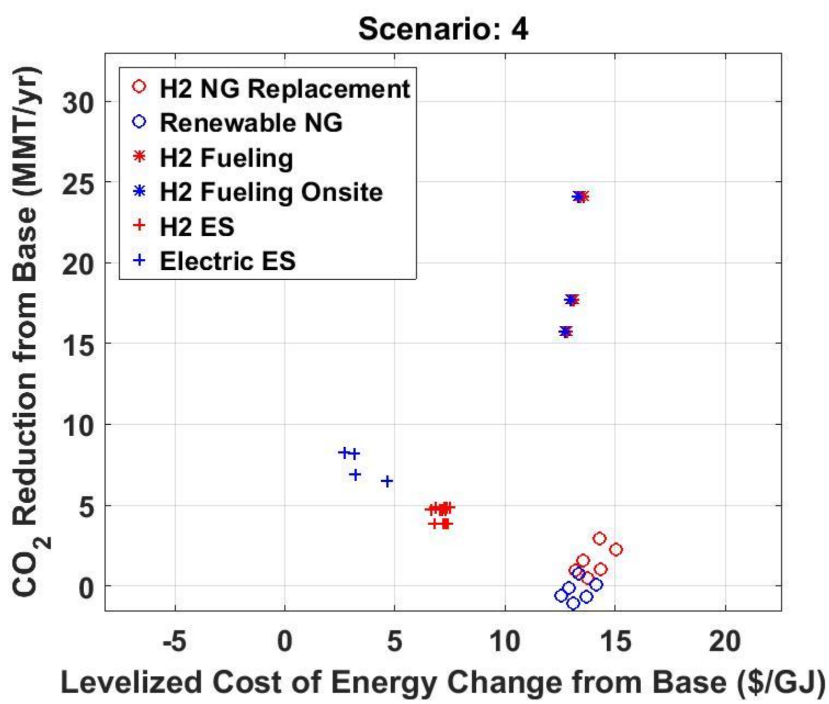

Figure 16: CO_2 Reduction versus LCOE change from base case for Scenario 4.

5.1.1 CO_2 Emission Reductions

The greatest amount of CO_2 reductions come from the H_2 Fueling use case in Scenario 3. This is due to the large amount of CO_2 emissions that comes from current gasoline vehicles. H_2 Fueling is able to offset transportation emissions by providing fuel for hydrogen fuel cell vehicles (FCVs) which have zero tail pipe emissions and replaces gasoline which has large CO_2 emissions, approximately 8,887 grams CO_2/gallon [68]. Scenario 3 also has no limitation on the equipment sizing which allows the electrolyzer to take in more otherwise curtailed power to produce more hydrogen for the FCVs. It also has a higher renewable capacity, so there is more available otherwise curtailed power. It should also be noted that in almost all scenarios the H_2 Fueling use case had the most CO_2 emission reductions, except Scenario 1. In Scenario 1, the battery electric ES use case had the most CO_2 emission reductions. Battery electric ES has the highest efficiency than any other use cases and provide more emissions reductions compared to hydrogen energy storage. However, the potential CO_2 emission reduction is limited by the relatively clean California electric grid: once the energy storage system is able to eliminate the need for natural gas power plants, no further emissions reductions can be obtained. This can be seen in Scenarios 3 where all ES use cases seem to be limited by a CO_2 reduction of 16.5 MMT/yr. Once the ES cases are able to offset as much of the electricity sector as it can, the CO_2 emission reductions stop. The transportation sector has more potential in lowering CO_2 emissions.

The natural gas use cases exhibited the least amount of CO_2 reduction. Renewable NG requires an extra step of methanation which reduces the overall efficiency, resulting in lower CO_2

emission reductions. 4 pathways in Scenario 4 result in an increase in CO_2 emissions. These pathways are part of the Renewable NG use case with Alkaline and PEM Electrolyzers. The Solid Oxide Electrolyzer has a reduction in CO_2 emissions due to its high efficiency due to using waste heat. The increase in CO_2 emissions is only seen in Scenario 4 due to the capacity limitation of the electrolyzer. Since scenario 4 limits the peak electrolyzer capacity to maintain a reasonable capacity factor, the electrolyzers are unable to follow renewable variability as closely. At the same time, these electrolyzers must still meet the given demand for gas. The limitation results in using non-renewable power to produce methane, resulting in natural gas being used to provide electricity generation, which is then use to produce natural gas. Therefore, while these are presented as part of the modeling results, these 4 pathways showing emissions increases are not practically realistic as such a mode of operation would never be pursued. In practice, this could be remedied by decreasing the methane demand, but for this study in order to compare each pathway a constant demand was imposed.

5.1.1.1 SOEC Contribution to CO_2

SOEC pathways have to rely on two energy sources, electricity and heat. In HiGRID, the heat is considered as primarily from waste heat from load follower and peaker power plants. But, in these high renewable capacity scenarios there are not enough load follower and peaker power plants to supply enough waste heat for the SOEC pathways. Table 9 displays the SOEC pathways and shows the percentage of CO_2 from SOEC pathways compared to the entire amount of CO_2 emitted.

Table 9: Percentage of CO_2 contribution from excess heat required from SOEC pathways.

Scenario	Renewable Fuel to NG Pipeline	Renewable Fuel for Transportation	Energy Storage
1	0.1967%	0.2206%	0.9465%
2	0.1960%	0.2202%	0.0003%
3	0.7651%	0.9314%	1.9992%
4	0.5864%	0.7014%	0.0017%

Most SOEC pathways are under 1% of CO_2 emissions except for energy storage case, scenario 3. The energy storage case has a larger percent of CO_2 emissions due to the use case offsetting load follower and peaker power plants, further reducing the availability of waste heat. The percentage of CO_2 is also higher with a higher renewable capacity due to the reduction of load follower and peaker power plant capacities. Although these SOEC cases require more waste heat than what is available through load follower and peaker plants alone, in actual operation the installation of new combustion based heat sources would not be used. Some future work would be to incorporate the usage of waste heat from industrial sources or from other thermal sources, such as solar or nuclear, instead of relying purely on load follower or peaker plants.

5.1.2 Levelized Cost of Energy Change from Base Case

The ES use cases typically have lower changes in LCOE than other use cases since they are replacing electricity production technologies on the grid. The ES use cases incorporate the same renewable mix as other use cases but with the addition of energy storage technologies which tend to be expensive and therefore can potentially increase the LCOE when the services provided to the grid do not offset their capital costs, as seen by the negative values in Scenario 1 and 3. These negative values are associated with Electric ES, primarily Li-Ion, Advanced Lead-

Acid, and Sodium-Sulfur Batteries. The flow battery considered provides the lowest cost impact of the Electric ES cases and in certain conditions can actually reduce LCOE from the base value. From a total LCOE perspective, the H_2 ES pathways are less expensive than the Electric ES but with the tradeoff of generally providing lower CO_2 reductions.

For the ES use cases, LCOE is changed both by capacity limitation and installed renewable capacity. The capacity factor of the pathway technologies increases with capacity limitation, around a 6-7% capacity factor for Scenarios 1 and 3 and around a 20% capacity factor for Scenarios 2 and 4. Increasing the capacity factor decreases the costs that product outputs must be sold at which benefits the LCOE. Scenarios without a capacity limitation for the ES use cases, however, can help reach renewable penetrations of 85% for Scenario 1 and 89% for Scenario 3. With the capacity limitation (Scenarios 2 and 4), achieved renewable penetrations are generally lower at about 75% and 81%, respectively. LCOE changes more so with higher renewable capacity than with capacity limitation for H_2 NG Replacement, Renewable NG, and H_2 Fueling use cases. This is due to the relatively small effect these use cases have on the LCOE since they do not replace electricity production technologies that are already on the grid, unlike the ES use cases.

5.1.3 Renewable Portfolio Standard

The RPS for each use case and scenario mix can be seen in Table 10. It should be noted that although the renewable fuel for transportation results in the highest CO_2 emission reductions, it does not result in the highest RPS. This is due to the producing hydrogen for either renewable fuel to NG pipeline or transportation is not as flexible as energy storage. An hourly fuel demand must be met, limiting the capabilities of utilizing the otherwise curtailed renewable power to increase the RPS. The effects of changing hydrogen demand and electrolyzer capacity will be further analyzed later in this thesis.

Table 10: The approximate RPS of each use case and scenario.

Scenario	Renewable Fuel to NG Pipeline	Renewable Fuel for Transportation	Hydrogen Energy Storage	Electric Energy Storage
1	74%	74%	85%	84%
2	74%	74%	75%	77%
3	80%	80%	89%	87%
4	76%	76%	81%	81%

5.2 Investor Perspective

The capacity factors for the renewable gas and fueling use cases are higher than the energy storage use cases, shown in Table 11, as a result of their dispatch. The renewable gas and fueling use cases have capacity factors that are affected by on the hydrogen demand as well as the capacity limitation. Since the results can vary widely with hydrogen demand, an analysis looking further into the effect of different hydrogen demands is presented later in this report. The energy storage use case capacity factors are dependent on the amount of discharge rather than charge while the capacity depends on the maximum discharge or charge power levels. The charge capacity may be larger than the discharge capacity in order to intake all the curtailed renewable power which will result in low capacity factors. The energy storage is also limited since it can only discharge after charging and thusly has a limitation of capacity factor of 50%. The energy storage use cases also follow renewable power generation closely, which has itself has low capacity factor of less than 30%.

Table 11: Capacity factors for each use case and scenario.

Scenario	Renewable Fuel to NG Pipeline	Renewable Fuel for Transportation	Hydrogen Energy Storage	Electric Energy Storage
1	7%	7%	7%	8-10%
2	35%	35%	20-22%	21-28%
3	9%	9%	6.5%	8-10%
4	68%	68%	22-24%	23-30%

The investor perspective of cost of energy, presented in Table 14, Table 15, and Table 17, show the minimum and maximum energy costs associated to each use case pathway technology mix. The cost is calculated as the costs over the energy provided by the equipment in each individual use case, not the energy provided by the entire energy system as in the grid-perspective analyses. Some technologies result in lower cost of energy, such as the alkaline electrolyzer over the PEM or solid oxide electrolyzer, but the individual technology values are not presented in the tables and are represented in span from maximum to minimum costs per use case. The values presented in the tables do not differentiate between each pathway; all individual pathway values can be found in the Appendix.

The tables show LCOE of different scenarios and electricity costs of each use case. Since the use cases are utilizing otherwise curtailed power, it may be possible for the use cases to have a special rate of electricity cost less than the cost of electricity on the grid. Therefore, it's important to consider different electricity costs. Four different electricity costs were considered: portfolio, 3 cents/kWh, 1 cent/kWh, and no costs. The portfolio cost is the cost of electricity on the electric grid using the corresponding electric resource mix in each scenario, which is the same for all use cases. The portfolio cost can be seen in Table 12 and Table 13.

Energy storage use case has different portfolio costs due the energy storage cases offsetting the portfolio technologies by replacing load following and peaking power plants. The 3 and 1 cents/kWh electricity costs correspond to low potential costs of electricity. No costs equates to free electricity in which electrolyzers will only take in excess renewables which could be potentially be priced at zero dollars. The green text represents the lowest costs and the red text represents the highest costs pathway and scenario per electricity cost.

Table 12: The approximate portfolio cost for ES use case per scenario.

Scenarios	H_2 into Fuel Cell (cents/kWh)	Battery (cents/kWh)
1	19	23
2	23	24
3	22	27
4	28	30

Table 13: The approximate portfolio cost for NG and Transportation Fuel use cases per scenario.

Scenarios	Portfolio Cost (cents/kWh)
1	23
2	23
3	27
4	27

5.2.1 Electric Grid Services as Energy Storage

Energy Storage use case is focused on evaluating the technical impact and business case feasibility of P2G systems applied to provide electric grid services as energy storage. This corresponds to use case 8 and 9 and pathways 22 to 37. The technology pathways considered are an electrolyzer coupled with a fuel cell and electric batteries. As stated in the introduction, all pathways and use cases for ES are run through the ES Module. In general, the alkaline electrolyzer, solid oxide fuel cell, and zinc bromide flow battery exhibited the lowest energy costs while the PEM electrolyzer, phosphoric acid fuel cell and Li-Ion battery exhibited the highest energy costs.

The lowest energy costs seen in Table 14 are with capacity limitation scenarios, scenarios 2 and 4. The capacity limitation can decrease the costs by more than half (as seen by comparing scenario 1 with scenario 2 and scenario 3 with scenario 4), since the capacity factors are nearly five times larger with a limitation, seen in Table 11. Scenario 2 has lower energy costs than scenario 4 for only the portfolio electricity cost because of the lower installed capacity of renewables which results in a lower portfolio cost, seen in Table 12.

The highest energy cost cases are seen in scenario 3. This is due to scenario 3 having a slightly lower capacity factor. The operation of energy storage matches load follower and peaker plants and, at higher renewable capacities, there are less load follower and peaker plants but the energy storage will still have a larger capacity in order to intake all the otherwise curtailed power, resulting in a lower capacity factor.

Table 14: Investor perspective LCOE with different scenarios and electricity costs for the ES use case.

Scenario	Electricity cost	H_2 into Fuel Cell; Electricity to Grid ($/MWh)			Battery Charge/Discharge to Grid ($/MWh)		
1	Portfolio	952.07	-	1495.87	507.49	-	1056.44
	3 cents/kWh	755.67	-	1302.28	275.35	-	808.99
	1 cent/kWh	730.94	-	1277.58	250.65	-	784.29
	No Costs	718.58	-	1265.23	238.30	-	771.94
2	Portfolio	523.02	-	709.93	387.12	-	575.01
	3 cents/kWh	272.82	-	461.72	125.30	-	308.65
	1 cent/kWh	248.09	-	437.02	100.60	-	283.95
	No Costs	235.73	-	424.68	88.26	-	271.60
3	Portfolio	1035.10	-	1607.81	565.18	-	1140.66
	3 cents/kWh	800.05	-	1377.58	285.24	-	833.66
	1 cent/kWh	775.32	-	1352.88	260.54	-	808.97
	No Costs	762.95	-	1340.53	248.19	-	796.62
4	Portfolio	565.92	-	736.90	448.46	-	628.51
	3 cents/kWh	253.38	-	426.01	120.00	-	295.42
	1 cent/kWh	228.65	-	401.32	95.30	-	270.72
	No Costs	216.29	-	338.97	82.95	-	258.38

5.2.2 Renewable Transportation Fuel for Fuel Cell Vehicles

Transportation Fuel use case is focused on evaluating the technical impact and business case feasibility of P2G systems applied to produce renewable transportation fuel for fuel cell vehicles. This corresponds to use cases 5, 6, and 7 and pathways 13 to 27. The technology pathways involve an electrolyzer and fueling stations. As stated in the introduction, all pathways and use cases for fueling are run through the HED Module. In general, the alkaline electrolyzer exhibited the lowest energy costs while the PEM electrolyzer exhibited the highest energy costs. The ranges of costs are shown in Table 15.

Table 15: Investor perspective LCOE with different scenarios and electricity costs for the Transportation Fuel use case.

Scenario	Electricity cost	H_2 for FCV, offsite production ($/kg)			H_2 for FCV, onsite production ($/kg)		
1	Portfolio	18.53	-	23.43	19.03	-	23.57
	3 cents/kWh	7.99	-	10.61	8.38	-	10.75
	1 cent/kWh	6.83	-	9.34	7.21	-	9.48
	No Costs	6.25	-	8.70	6.63	-	8.85
2	Portfolio	13.90	-	17.69	14.41	-	17.83
	3 cents/kWh	4.16	-	5.25	4.55	-	5.45
	1 cent/kWh	3.00	-	4.36	3.38	-	4.56
	No Costs	2.42	-	3.91	2.80	-	4.12
3	Portfolio	19.13	-	24.40	19.63	-	24.54
	3 cents/kWh	7.19	-	9.41	7.58	-	9.55
	1 cent/kWh	6.03	-	8.14	6.42	-	8.28
	No Costs	5.45	-	7.63	5.83	-	7.84
4	Portfolio	15.11	-	19.47	15.61	-	19.61
	3 cents/kWh	3.68	-	4.71	4.07	-	4.91
	1 cent/kWh	2.52	-	3.82	2.90	-	4.02
	No Costs	1.94	-	3.37	2.32	-	3.58

The lowest energy costs are seen in scenarios with a capacity limitation, similar to the results in the Energy Storage use case. Imposing a capacity limitation is able to increase the capacity factor by 5-fold, seen in Table 11. Similar to the results in the Energy Storage use case, energy costs are lower in scenario 2 than scenario 4 due to the lower portfolio electricity cost, seen in Table 13, since less renewables are available on the electric grid in scenario 2. Scenario 4 is the lowest for all other electricity costs due to the larger capacity factor.

The highest cases are seen in scenario 1 and 3. Scenario 3 is the highest case for portfolio cost due to the larger capacity of installed renewables which has a higher portfolio cost than scenario 1. Scenario 1 is the highest for all other electricity costs, different than the Energy Storage use case, due to the lower capacity factor, seen in Table 11.

5.2.2.1 Fuel Cell Vehicle Penetration Effects

The FCV penetration, the percentage of vehicles that are FCVs, can be seen in Table 16. The values were calculated based on the curtailment from the base case, detailed in the Calculations section above. This was to ensure the hydrogen demand could be produced from only renewable power while allowing the model to run different scenarios with ease.

Table 16: FCV penetration percentages per scenario.

Scenarios	FCV penetration
1 & 2	8-11%
3 & 4	12-18%

But, it is possible for the FCV penetration to have a strong effect on the results. As an example, Figure 17, scenario 1, and Figure 18, scenario 3, show how the renewable penetration and the curtailed power percentage changes with FCV penetration for scenarios 1 and 3. Scenarios 1 and 3 were considered in order to span different renewable capacities as well as ensure no capacity limitation for the electrolyzers producing hydrogen to intake as much curtailed power as possible.

The renewable penetration has a peak around a FCV penetration of 20% for scenario 1 and 33% for scenario 3. The renewable penetration increases because the extra load from the electrolyzers are able to utilize more curtailed power than the base case. The renewable penetration decreases once the extra load is too large and needs to be met with non-renewable power. The renewable penetration falls below the base case when the hydrogen demand is too large, this can be seen in the curtailed power percentage. Seen in Figure 17, the renewable penetration falls below the base case when the curtailed power percentage reaches close to zero. This shows that the renewable capacity needs to be larger at higher FCV penetrations in order for hydrogen production to be 100% renewable. Figure 20, scenario 3, shows that the renewable penetration is above the base case at higher FCV penetrations because the renewable capacity can handle the extra load but overall shows the same trends seen in Figure 17.

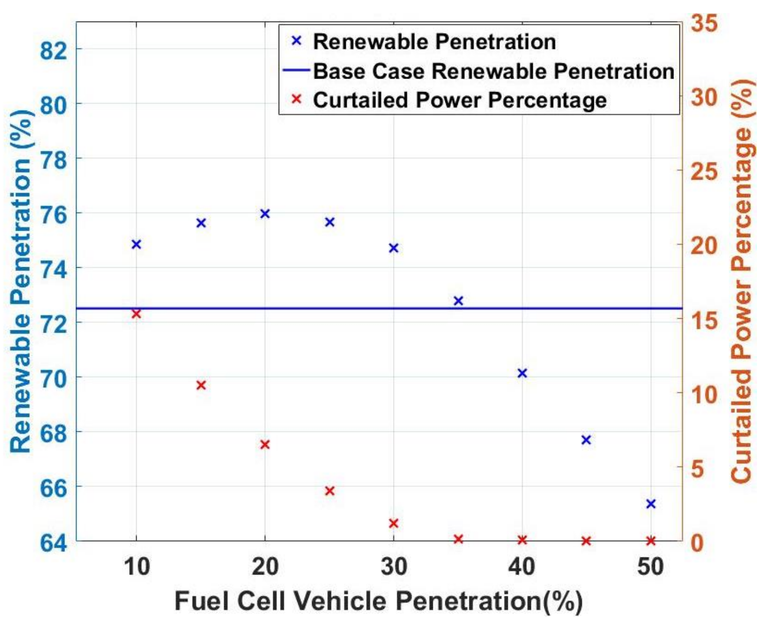

Figure 17: Change in RPS and curtailed power percentage with increasing FCV penetration for scenario 1.

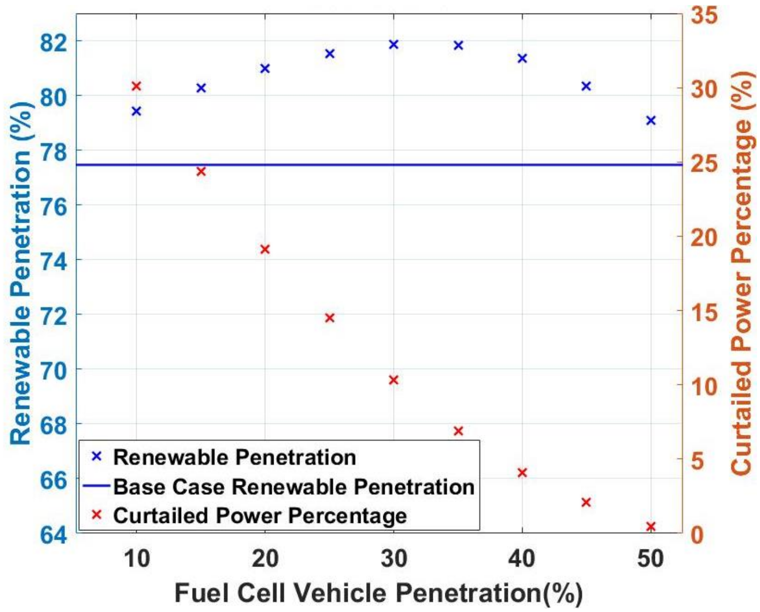

Figure 18: Change in RPS and curtailed power percentage with increasing FCV penetration for scenario 3.

5.2.3 Renewable Natural Gas for Natural Gas Usage Types

Natural Gas use case is focused on evaluating the technical impact and business case feasibility of P2G systems applied to produce renewable fuel for the natural gas system. This corresponds to use cases 1 and 2 and pathways 1 to 12. The technology pathways involve an electrolyzer and methanator. As stated in the introduction, all pathways and use cases for fueling are run through the HED Module. The investor perspective LCOE can be seen in Table 17. In general, the alkaline electrolyzer exhibited the lowest energy costs while the PEM electrolyzer and the addition of methanation exhibited the highest LCOE. The ranges of costs are shown in Table 17.

Table 17: Investor perspective LCOE with different scenarios and electricity costs for the NG use case.

Scenario	Electricity cost	H_2 into Natural Gas System ($/MMBtu)			CH_4 into Natural Gas System ($/MMBtu)		
1	Portfolio	125.10	-	167.12	184.18	-	240.81
	3 cents/kWh	49.64	-	71.92	87.13	-	127.58
	1 cent/kWh	40.97	-	62.45	76.81	-	116.32
	No Costs	36.63	-	57.72	71.65	-	110.70
2	Portfolio	90.64	-	121.54	116.27	-	153.35
	3 cents/kWh	21.10	-	26.31	31.09	-	40.09
	1 cent/kWh	12.42	-	17.72	20.78	-	29.56
	No Costs	8.09	-	14.41	15.62	-	25.62
3	Portfolio	129.57	-	173.46	183.90	-	241.42
	3 cents/kWh	43.69	-	62.42	75.45	-	109.36
	1 cent/kWh	35.02	-	52.95	65.14	-	92.10
	No Costs	30.68	-	48.22	59.98	-	92.47
4	Portfolio	98.81	-	134.50	122.61	-	164.56
	3 cents/kWh	17.50	-	20.57	24.03	-	29.07
	1 cent/kWh	8.83	-	13.45	13.71	-	21.08
	No Costs	4.49	-	10.14	8.56	-	17.15

The lowest energy costs for the Natural Gas use case are identical to those in the two previous use cases, scenarios 2 and 4. The main factor is the capacity limitation which helps to increase the capacity factor which in turns decreases the costs. For all use cases, the lowest energy cost was always associated to the highest capacity factors, seen in Table 11, unless the costs were high. If the electricity cost was high, such as for the portfolio cost case, then the electricity cost was the main deciding factor in the lowest energy cost.

The highest energy costs are also identical to the Transportation Fuel use case. Both the Transportation Fuel and Natural Gas use case show similar trends while the Energy Storage use case has slightly different highest energy cost results. This shows that since the pathways in the renewable gas use case are decoupled from the electricity sector, the amount of renewables available does not dramatically change the cost of energy. For both the Transportation Fuel and Natural Gas use case, the capacity factor is the main factor that determines energy costs unless the cost of electricity is high.

5.2.3.1 Percent of Hydrogen in the Natural Gas pipeline

The percent of hydrogen is around or below 1% by volume in the natural gas pipeline, seen in Table 18. This percentage was calculated without time or spatial resolution and based off of a year's production and usage. In other words, the total amount of hydrogen produced in a year over the total amount of natural gas consumed in a year. It can be seen that the percentage of hydrogen falls well below the suggested 20% by volume mixture with natural gas.

Table 18: Percentage by volume of hydrogen in the NG pipeline.

Scenario	Alkaline, Dist.	SOEC, Dist.	PEM, Dist.	Alkaline, Trans.	SOEC, Trans.	PEM, Trans.
1	0.77%	1.31%	0.65%	0.77%	1.31%	0.65%
2	0.77%	1.31%	0.65%	0.77%	1.31%	0.65%
3	0.78%	1.33%	0.65%	0.78%	1.33%	0.65%
4	0.82%	1.40%	0.69%	0.82%	1.40%	0.69%

5.2.4 $/GJ Basis

The previous use cases have different measurements of dollars per unit of energy. In order to compare each technology, the average costs are all in $/GJ, seen in Table 19. Although all use cases are compared on a GJ basis, this does not define the best use case because there is a different usefulness of each use case. For example, H_2 and CH_4 into natural gas system will need to be burned in order to become useful, which will have an efficiency drop to convert fuel to electricity. H_2 for fueling will also need to be converted in a FCV in order to become useful energy. Only ES cases come in a form that is directly useful electricity, which is why the ES case is relatively high in $/GJ.

Table 19: Comparison of an average of all use cases and electricity costs on a $/GJ basis.

Scenario	Electricity cost	H_2 into NG ($/GJ)	CH_4 into NG ($/GJ)	H_2 for Fueling ($/GJ)	ES ($/GJ)
1	Portfolio	136.27	195.50	146.73	303.97
	3 cents/kWh	57.30	101.58	67.56	246.07
	1 cent/kWh	49.46	92.25	59.72	239.16
	No Costs	45.54	87.59	55.80	235.70
2	Portfolio	101.62	128.23	113.24	161.88
	3 cents/kWh	22.63	34.28	34.05	91.05
	1 cent/kWh	14.79	24.96	26.21	84.13
	No Costs	10.87	20.30	22.29	80.68
3	Portfolio	142.39	197.36	153.21	328.93
	3 cents/kWh	50.22	87.72	60.72	259.27
	1 cent/kWh	42.38	78.40	52.88	252.36
	No Costs	38.46	73.74	48.96	248.90
4	Portfolio	112.43	137.81	124.56	173.51
	3 cents/kWh	18.36	25.93	29.92	84.90
	1 cent/kWh	10.52	16.60	22.09	77.99
	No Costs	6.60	11.94	18.17	74.54

Overall, the lowest result is H_2 into NG system for scenario 4 and no electricity cost. Renewable hydrogen only requires an electrolyzer for equipment, resulting in the lowest $/GJ cost of energy. Methane renewable gas requires both an electrolyzer and a methanator, which has a higher cost than the hydrogen renewable gas use case. The H_2 for fueling requires an electrolyzer and has an additional transportation cost detailed in Table 6. The CH_4 into the NG pipeline case is lower than the H_2 for fueling case only when there is a capacity limitation. This is due to H_2 for fueling having a larger variable cost and CH_4 into NG having a larger instant cost. At higher capacity factors, the variable cost become dominant; while at lower capacity factors, the instant and fixed costs are dominant.

5.2.5 Effects of Electricity cost

Per scenario, portfolio electricity cost results in the highest cost of energy and no costs electricity cost results in the lowest. The no cost electricity case represents the minimum costs of each scenario, in which the costs are entirely dependent on capacity factor. The average difference of each electricity cost (1 cent/kWh, 3 cents/kWh, and portfolio) from the no cost can be seen in Table 20. The portfolio costs are between 20 – 30 cents/kWh, detailed in Table 12 and Table 13, up to 10 times larger than the 3 cents/kWh. It should also be noted that the additional costs have similar trends as the electricity costs. The portfolio additional costs are around 10 times larger than the 3 cents/kWh additional costs. This is due to at lower electricity costs; the additional costs may differ by a couple cents and be relatively small which would not show up when taking the average difference of additional costs across different pathways.

Even though the additional costs presented in Table 20 are similar, the percentage of the additional costs relative to the total costs are different, seen in Table 21. The percentages show that the cost of electricity is more significant when the capacity factors are high, scenarios 2 and 4, than when they are low, scenarios 1 and 3. When the capacity factors are high, the electrolyzers need more electricity which would raise the percentage of costs due to electricity. When the capacity factors are low, the main costs come from the equipment costs. Since the electrolyzers are not operating as much they don't require variable costs, such as electricity.

Table 20: An average of additional costs imposed onto the LCOE for each electricity cost, use case, and scenario.

Scenario	Electricity cost	Renewable Gas ($/MMBtu)	H_2 for Fueling ($/kg)	ES ($/MWh)
1	Portfolio	110.13	13.53	254.46
	3 cents/kWh	14.89	1.82	37.06
	1 cent/kWh	4.96	0.61	12.35
	No Costs	0.00	0.00	0.00
2	Portfolio	104.52	12.65	293.70
	3 cents/kWh	13.71	1.54	37.06
	1 cent/kWh	4.18	0.51	12.35
	No Costs	0.00	0.00	0.00
3	Portfolio	124.25	15.23	300.11
	3 cents/kWh	14.89	1.75	37.06
	1 cent/kWh	4.96	0.53	12.35
	No Costs	0.00	0.00	0.00
4	Portfolio	120.04	14.65	358.30
	3 cents/kWh	12.71	1.54	37.06
	1 cent/kWh	4.18	0.51	12.35
	No Costs	0.00	0.00	0.00

The instant costs for the energy storage cases are larger by a factor of ten than the renewable gas and fueling cases. This is why the electricity costs account for a larger percentage for renewable gas and fueling than the energy storage cases. This is also why the energy storage cases had a greater difference in portfolio costs, seen in Figure 13 to Figure 16. With a larger instant cost, the use case economic results are more dependent on capacity factor. With lower instant costs, the use case economic results are more dependent on electricity cost.

Table 21: The average percentage of electricity input costs relative to the total LCOE.

Scenario	Electricity cost	Renewable Gas	H_2 for Fueling	ES
1	Portfolio	61%	64%	25%
	3 cents/kWh	18%	19%	5%
	1 cent/kWh	7%	7%	2%
	No Costs	0%	0%	0%
2	Portfolio	87%	79%	53%
	3 cents/kWh	46%	32%	13%
	1 cent/kWh	21%	13%	5%
	No Costs	0%	0%	0%
3	Portfolio	68%	69%	28%
	3 cents/kWh	20%	21%	4%
	1 cent/kWh	8%	7%	15%
	No Costs	0%	0%	0%
4	Portfolio	92%	84%	60%
	3 cents/kWh	56%	35%	14%
	1 cent/kWh	30%	15%	5%
	No Costs	0%	0%	0%

5.2.6 Best Pathway per Use Case

This section will summarize the pathways with lowest cost of energy per use case, displayed in Table 22. The table displays the costs of energy based on different electricity costs in Scenario 4. Scenario 4 tended to have the lowest costs than all other scenarios so it was chosen to represent the best possible cases for each use case. The results are compared to current costs to grasp an understanding of how each pathway costs relative to current technologies.

For the use case of H_2 into NG system, the cost of electricity would have to be around 5 cents/kWh in order for the cost of energy from the pathway to match current costs. For the use case of CH_4 into NG system, all cases are greater than the current cost of natural gas. With no electricity costs, just the equipment and operational costs, the price of renewable methane is too expensive to be competitive with current prices. Projected natural gas prices also do not go over $8.56/MMBtu [69]. The results show that CH_4 into the NG pipeline is not competitive due to the cheap prices of nonrenewable natural gas from hydraulic fracturing. Similar to the H_2 into NG system, the electricity cost will determine the cost of hydrogen for the H_2 for fueling use case. The cost of electricity would have to be less than 9 cents/kWh to be result in hydrogen less than current costs. In the case of H_2 ES, even at no costs of electricity, the energy cost cannot be lower than the current costs. This may be due to the high costs of requiring two equipment sets: an electrolyzer and a fuel cell, and the lower round-trip efficiency compared to batteries. The Battery ES has the potential of matching current costs of electricity if the cost of electricity fed into the battery is less than $6/kWh.

Table 22: The pathway with the lowest cost of energy per use case compared to current costs [70].

Use Case	Renewable H_2 into NG pipeline	Renewable CH_4 into NG pipeline	H_2 for Fueling	H_2 ES	Battery ES
Pathway	Alkaline Electrolyzer into Dist. System	Alkaline Electrolyzer to Methanator; into Dist. System	Alkaline Central Plant Electrolyzer; Trucked Gaseous H_2 Trucked	Alkaline Electrolyzer H_2 into SOFC	ZnBr Flow Battery
Portfolio Cost	$98.81/MMBtu	$122.61/MMBtu	$7.99/kg	$565.92 /MWh	$448.4 6/MWh
3 cents /kWh	$17.50/MMBtu	$24.03/MMBtu	$3.68/kg	$253.38 /MWh	$200.0 0/MWh
1 cent /kWh	$8.83/MMBtu	$13.71/MMBtu	$2.52/kg	$228.65 /MWh	$95.30 /MWh
No Costs	$4.49/MMBtu	$8.56/MMBtu	$1.94/kg	$216.29 /MWh	$82.95 /MWh
Current Costs:	$26/MMBtu*	$3/MMBtu	$6.50/kg	$153.90 /MWh	$153.9 0/MWh

*Converted from $3.50/kg industrial cost of hydrogen.

5.3 Effects of Hydrogen Demand and Electrolyzer Capacity

The previous results from the HED module represent data set a constant electrolyzer capacity and hydrogen demand. The electrolyzer capacity and hydrogen demands were chosen based on the base case results. This next set of results looks into how hydrogen demand and electrolyzer capacity could affect the renewable penetration, capacity factor, portfolio cost, and cost of hydrogen. Four different hydrogen demands were considered, seen in Table 23, listed from least to greatest hydrogen demand. The data are presented in Figure 19 to Figure 22.

Table 23: Description of different hydrogen demands.

Hydrogen Demand	Description
H2demand 1	The hydrogen demand of a 1 GW electrolyzer constantly running.
H2demand 2	The hydrogen demand of a 2 GW electrolyzer constantly running
FCV demand 10	The hydrogen demand assuming 10% of all vehicles are FCVs.
FCV demand 20	The hydrogen demand assuming 20% of all vehicles are FCVs.

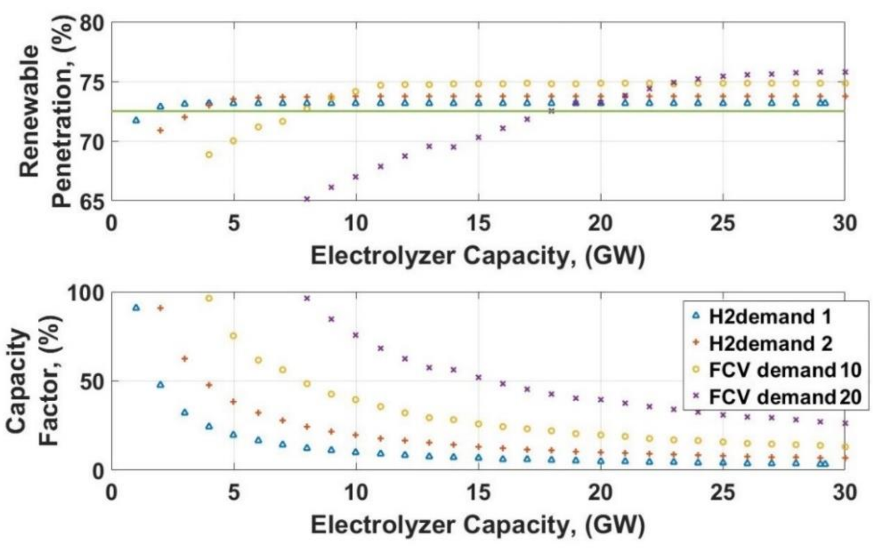

Figure 19: Renewable penetration and capacity factor versus electrolyzer capacity at 4 hydrogen demands for centralized AEC plant with gaseous H_2 trucked to fueling station, pathway 13.

The green line in the figures represents the value of the base case. As a representative example, pathways involving gaseous hydrogen trucked to a hydrogen fueling station with a renewable capacity of 147 GW were chosen as the base for this sensitivity analysis. The two equipment types compared are the alkaline central plant electrolyzer, pathway 13, and the solid oxide central plant electrolyzer, pathway 14. The PEM central plant electrolyzer was not chosen because the results from the PEM electrolyzer were less favorable than the other two equipment types. Each individual point in one of the graphs represents a single run in HiGRID.

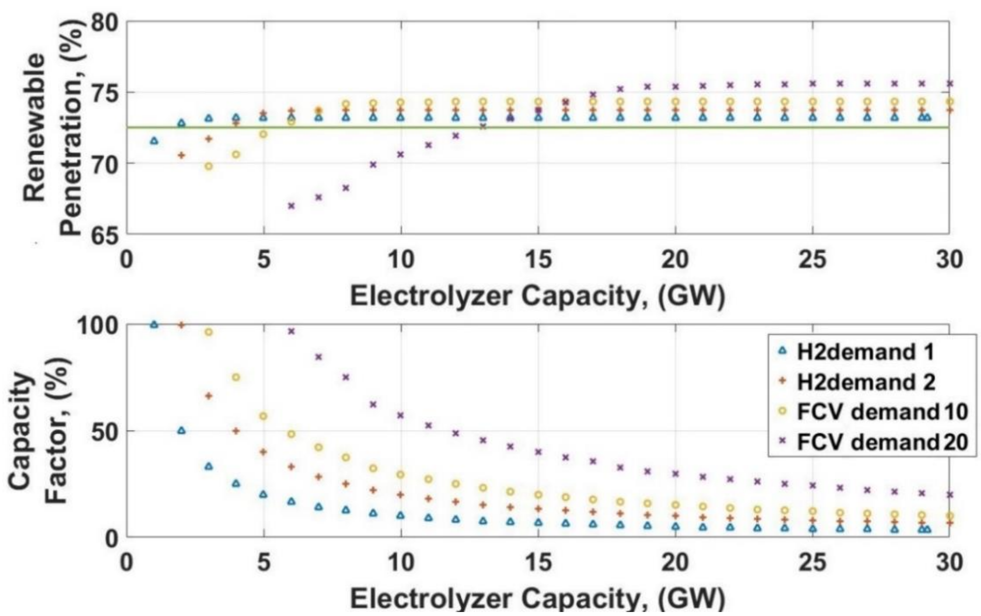

Figure 20: Renewable penetration and capacity factor versus electrolyzer capacity at 4 hydrogen demands for centralized SOEC plant with gaseous H_2 trucked to fueling station, pathway 14.

The main difference between the solid oxide and alkaline electrolyzer is the efficiency which results in different values but do not change the overall trends. Figure 19 and Figure 20 show the trends of renewable penetration, the top graph, and capacity factor, the bottom graph, with electrolyzer capacity. The renewable percentage increases with increasing hydrogen demand; this is due to adding flexible load which can intake more of the curtailed power. It should be noted that the hydrogen demand in these cases are still low enough to be met with only renewable power since the renewable capacities are so high. If the hydrogen demand exceeds the renewable capacities, the renewable penetration would not be able to surpass the base case. The capacity factor decreases at a slower rate with electrolyzer capacity at higher hydrogen demand. This is due to the electrolyzer capacity increment being relatively small compared to the hydrogen demand. For example, the electrolyzer capacity is increased by 100% from the first to the second point for H2demand 1 but only increased by 50% for H2demand 2. In order to rely on only renewable power for hydrogen production, which is to reach a renewable penetration above the base case, the capacity factor of the electrolyzer has to fall below 50%. This shows that the electrolyzer capacity will have to be two times larger than the hydrogen demand per hour.

Figure 21 and Figure 22 show economic effects with electrolyzer capacity. The solid oxide electrolyzer has higher costs of hydrogen than the alkaline electrolyzer due to the higher associated equipment costs. Since the results do not consider variation in the cost of electricity, the economics are mostly dependent on equipment and instant costs. The portfolio cost, the top graph, is relatively constant with increasing electrolyzer capacity. This is due to the small effect that the electrolyzer has relative to the entire portfolio of the energy system. The main factors in decreasing the portfolio cost are by increasing the hydrogen demand which is able to intake otherwise curtailed power. The cost of hydrogen, the bottom graph, increases linearly with electrolyzer capacity. The linear trend is due to the incremental increase in electrolyzer capacity, and since variation in the cost of electricity was not considered, the main costs are associated to equipment size which depends on capacity. The cost of hydrogen increases at a slower pace at higher hydrogen demand than lower hydrogen demand. This is due the electrolyzer capacity increment being relatively small compared to the hydrogen demand, similar to the capacity factor trend. The lower electrolyzer capacities have lower costs of hydrogen because they operate at a higher capacity factor. At higher capacity factors the electrolyzers are able to produce more hydrogen relative to the equipment costs, resulting in the decreasing cost of hydrogen.

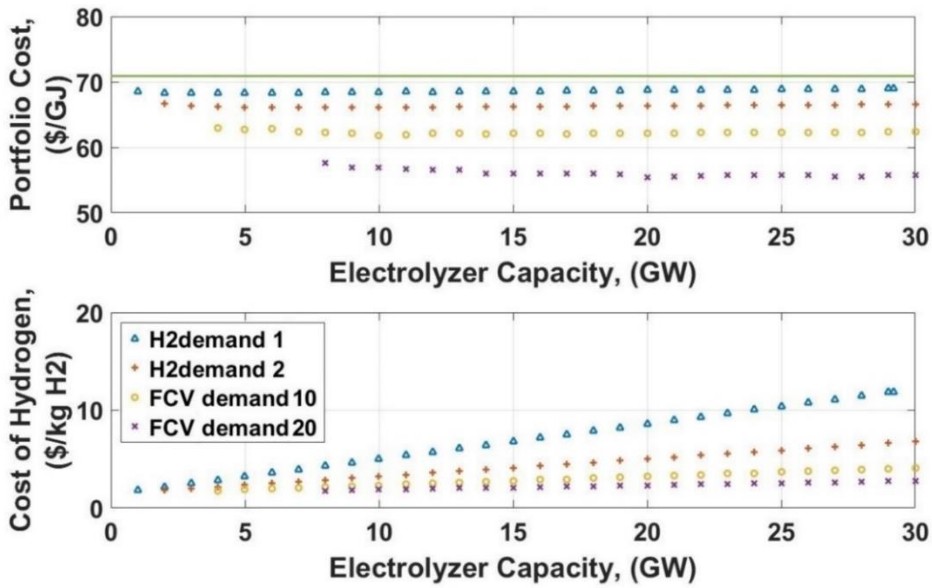

Figure 21: Portfolio cost and cost of hydrogen versus electrolyzer capacity at 4 hydrogen demands for centralized AEC plant with gaseous H_2 trucked to H_2 fueling station, pathway 13.

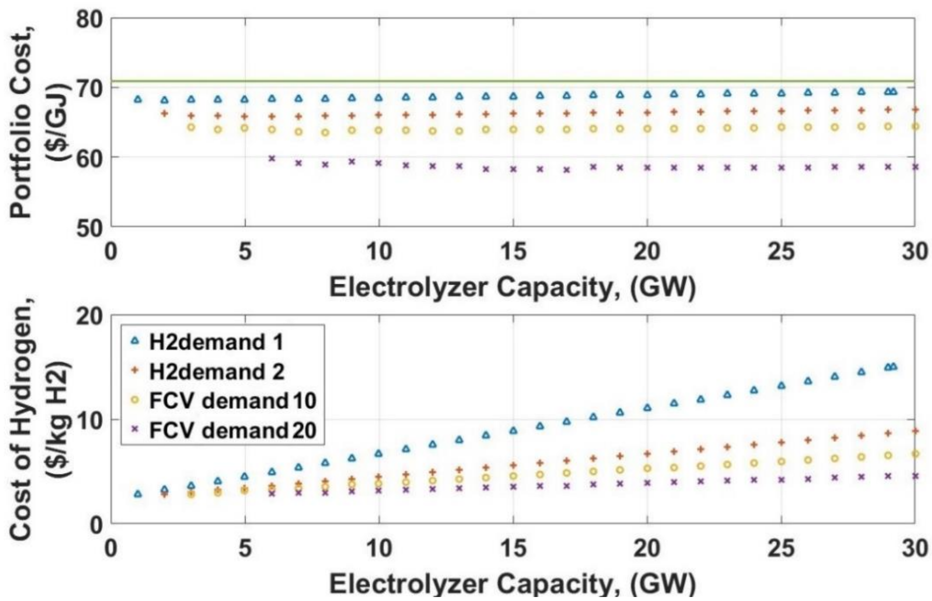

Figure 22: Portfolio cost and cost of hydrogen versus electrolyzer capacity at 4 hydrogen demands for centralized SOEC plant with gaseous H_2 trucked to H_2 fueling station, pathway 14.

5.4 Individual Electrolyzer Cases

All previous results have been shown from a fleet-wide perspective, specifically in terms of the average characteristics of the electrolyzer fleet. In order to understand how individual electrolyzers may operate and what the business case is for electrolyzer units deployed earlier in the fleet compared to those deployed later in the fleet, an analysis of how the economics vary for individual electrolyzers are presented. The first incremental units of electrolyzer capacity will be able to access more otherwise curtailed renewable generation compared to the later incremental units, since when the later units are deployed, much of the originally-available excess renewable generation will have already been consumed by the earlier-deployed units. Depending on when the electrolyzer units are deployed in the fleet, the capacity factors for individual units will be different, which affects costs. To examine this, extra cases were run for pathways involving gaseous hydrogen trucked to a hydrogen fueling station. These pathways were chosen in order to set up the HiGRID run and can be changed to any other pathway which uses the HED module, use cases 1 to 7. The individual electrolyzers are assumed to be operating separately from one another and receiving renewable power on a first installed first serve basis. In other words, after the first electrolyzer is installed the next electrolyzer will see less available otherwise curtailed power since the previous electrolyzer has already consumed some of it.

Two renewable mixes are considered, 147 GW and 184 GW, similar to the different scenarios presented in Table 4. Each individual electrolyzer is rated at 1 MW. The capacity factors shown in the following graphs represent the capacity factor of each individual electrolyzer. The electrolyzer capacity represents how many electrolyzers of 1 MW size could have a certain capacity factor. In order to read Figure 23 through Figure 41 use the following example:

The left y-axis and the blue histogram bar graph is the electrolyzer capacity which represents the amount of 1 MW electrolyzers installed at each capacity factor. For example, at a capacity factor of around 25% if an electrolyzer capacity is around 1000 MW it represents 1000 1MW electrolyzers installed. The electrolyzers at higher capacity factors are the first electrolyzers installed to intake the most amount of available curtailed power. The nth electrolyzer would be considered the sum of installed electrolyzers from higher capacity factors to lower capacity factors. For example, if 100 electrolyzers are at 50% capacity factor and 400 electrolyzers at capacity factor of 45% then a total of 500 electrolyzers are installed with capacity factors higher than 45% and the nth electrolyzer would be the 500^{th} electrolyzer at 45% capacity factor.

The right y-axis and the red line plot is the cost of hydrogen. The cost of hydrogen shown in these plots is the cost of hydrogen from each individual electrolyzer. For example, the electrolyzers which operate at a capacity of 50% all have the same cost of hydrogen which is around $2/kg. The cost of hydrogen considered for these extra cases do not considering the cost of electricity.

5.4.1 100% Renewable Hydrogen

In order for the hydrogen to be 100% renewable, all the electricity must come from renewable sources. At a Renewable Capacity of 147 GW, Figure 23 to Figure 25 show the histograms of how many electrolyzers could be at each capacity factor with each figure representing a different pathway. The overall trend of the histogram shows that as capacity factor decreases, there can be more electrolyzers installed at lower capacity factors. Since all the electricity comes from renewable sources, the capacity factors of the electrolyzers are highly dependent on those of the renewable sources. The electrolyzer capacity is fairly steady for capacity factor between 50% and 35% then as the capacity factor decreases pass 35% the electrolyzer capacity rapidly increases. This may be due to using all the relatively steady curtailed wind power and switching to primarily depending on peak curtailed solar power which has a capacity factor of its own around 30%. The cost of hydrogen increases at lower capacity factors, this is similar to the results previously shown.

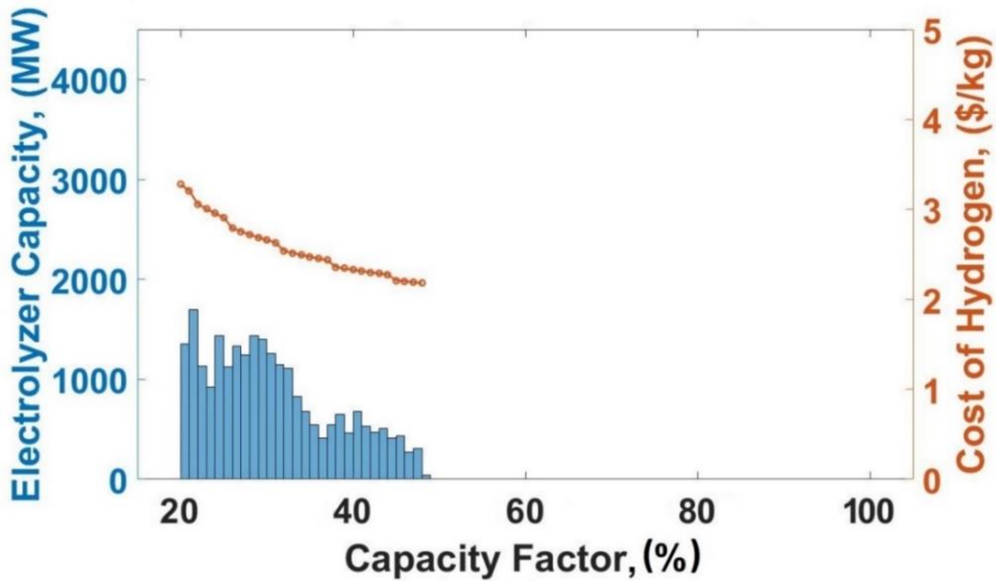

Figure 23: Electrolyzer capacity and cost of hydrogen of individual electrolyzers versus capacity factor at a renewable capacity of 147 GW, producing 100% renewable hydrogen through centralized AEC plant with gaseous H_2 trucked to H_2 fueling station, pathway 13.

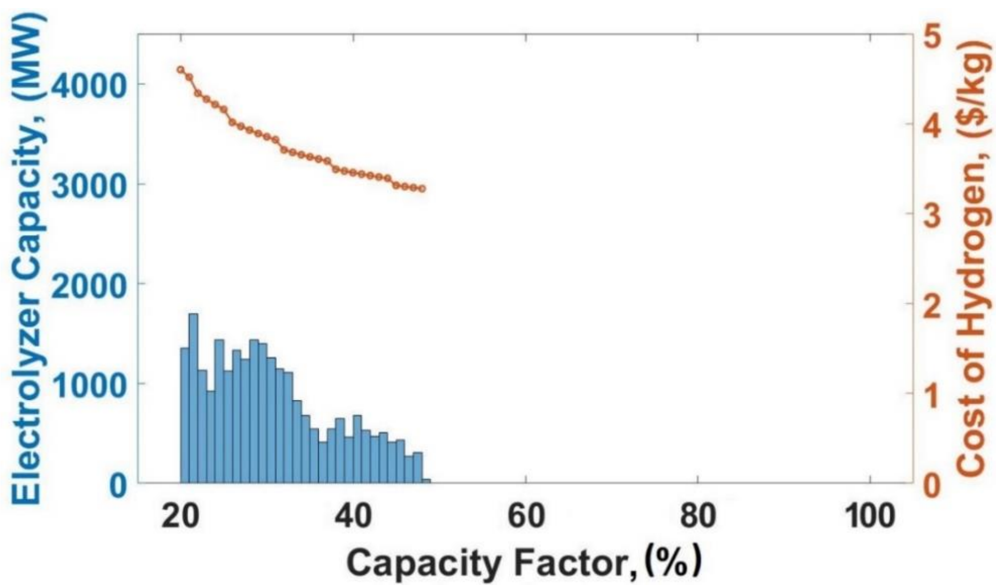

Figure 24: Electrolyzer capacity and cost of hydrogen of individual electrolyzers versus capacity factor at a renewable capacity of 147 GW, producing 100% renewable hydrogen through centralized SOEC plant with gaseous H_2 trucked to H_2 fueling station, pathway 14.

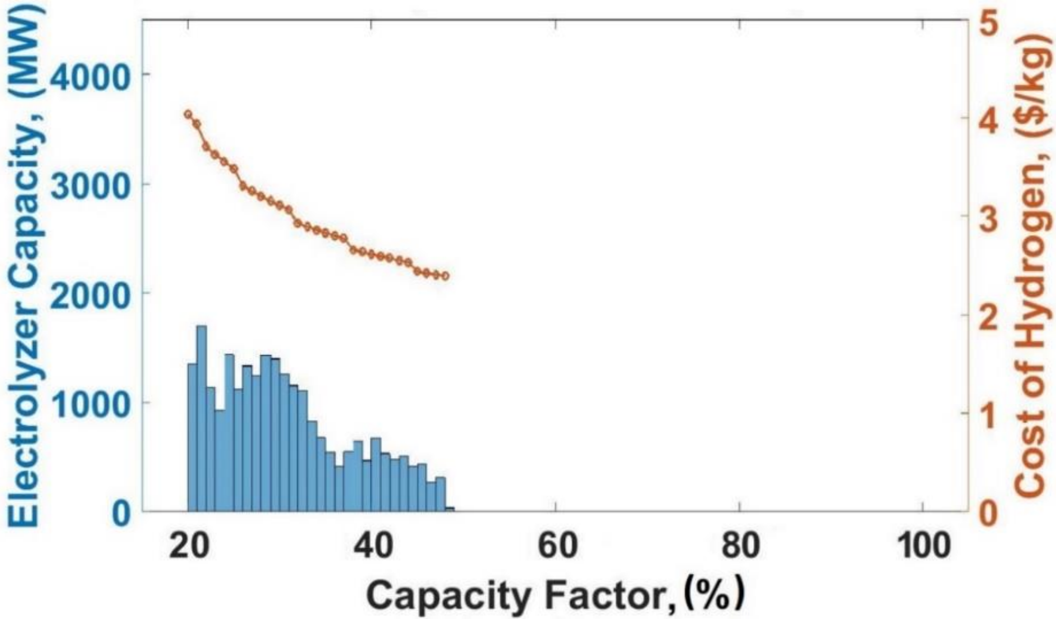

Figure 25: Electrolyzer capacity and cost of hydrogen of individual electrolyzers versus capacity factor at a renewable capacity of 147 GW, producing 100% renewable hydrogen through centralized PEM plant with gaseous H_2 trucked to H_2 fueling station, pathway 15.

Increasing the renewable capacity to 184 GW, Figure 26 to Figure 28 show the electrolyzers reaching a higher capacity factor and a lower cost than in Figure 23 to Figure 25. Since more renewable power is available to the electrolyzer, the capacity factors are higher. At higher capacity factors, the cost of hydrogen is lower. Figure 26 to Figure 28 also show the similar trend of an increase in electrolyzer capacity at decreasing capacity factor from 35% due to renewable power.

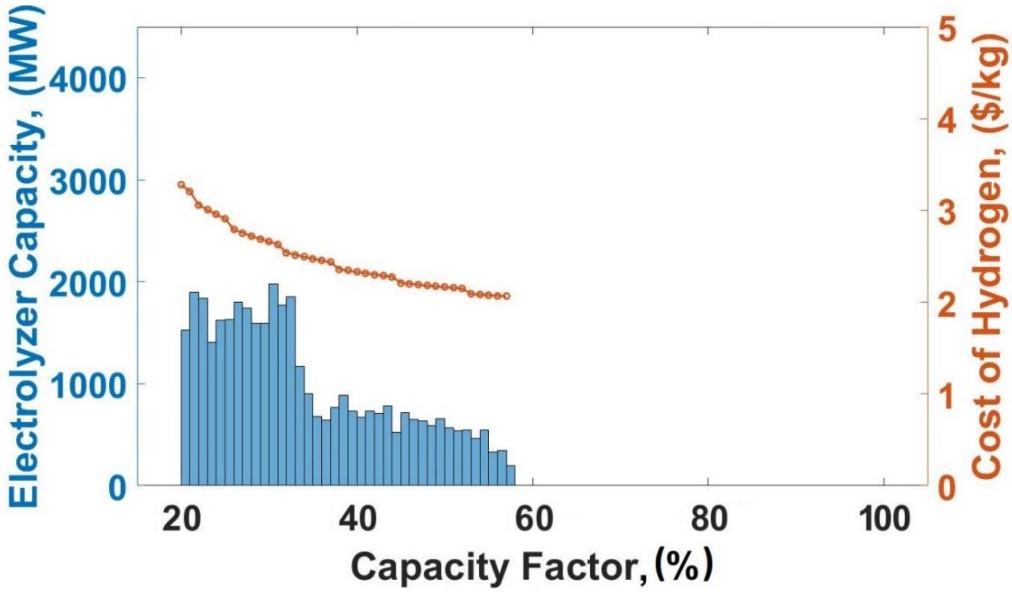

Figure 26: Electrolyzer capacity and cost of hydrogen of individual electrolyzers versus capacity factor at a renewable capacity of 184 GW, producing 100% renewable hydrogen through centralized AEC plant with gaseous H_2 trucked to H_2 fueling station, pathway 13.

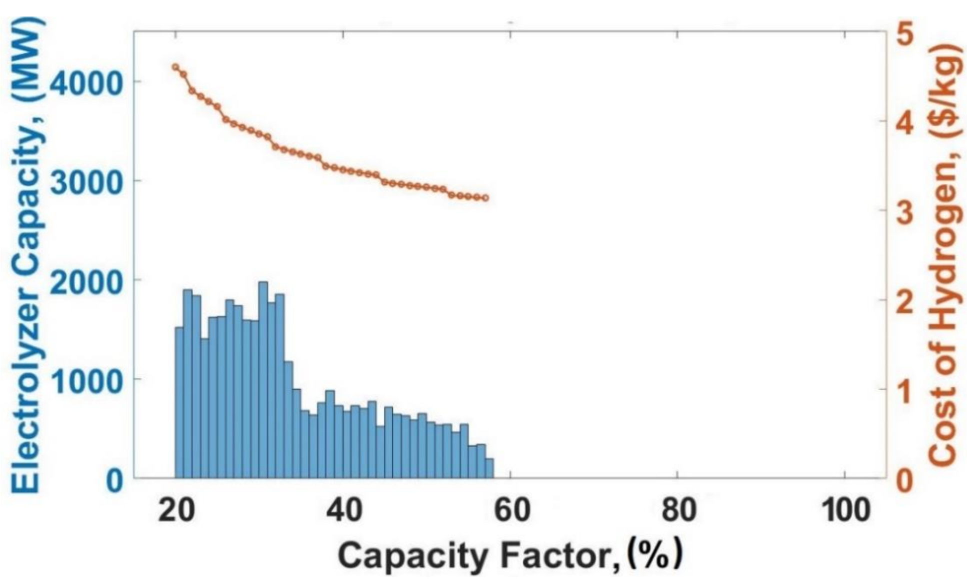

Figure 27: Electrolyzer capacity and cost of hydrogen of individual electrolyzers versus capacity factor at a renewable capacity of 184 GW, producing 100% renewable hydrogen through centralized SOEC plant with gaseous H_2 trucked to H_2 fueling station, pathway 14.

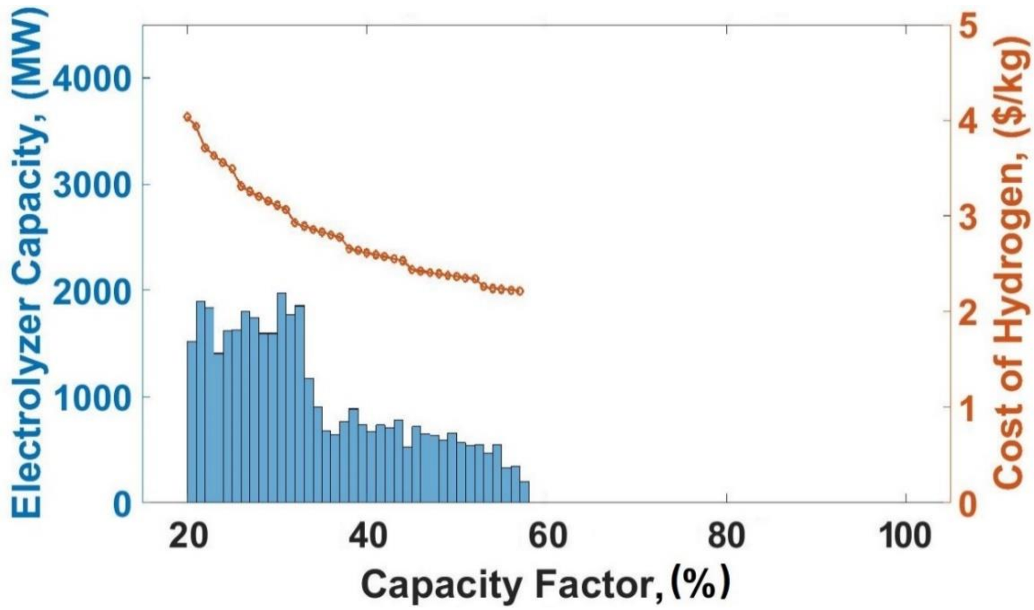

Figure 28: Electrolyzer capacity and cost of hydrogen of individual electrolyzers versus capacity factor at a renewable capacity of 184 GW, producing 100% renewable hydrogen through centralized PEM plant with gaseous H_2 trucked to H_2 fueling station, pathway 15.

5.4.2 80% Renewable Hydrogen

In order for the hydrogen to be 80% renewable, only 80% of the electricity must come from renewable sources. At a Renewable Capacity of 147 GW, Figure 29 to Figure 31 show the histogram of how many electrolyzers could be at each capacity factor. The capacity factor is able to reach 60% while it was only able to reach up to 50% for the 100% renewable case, but at the cost of overall renewable penetration of the grid. The renewable penetration dropped from 77.5% (for the 100% renewable hydrogen case) to 73.6% (for the 80% renewable hydrogen case). The increase in electrolyzer capacity seen in Figure 23 to Figure 28 at capacity factor of 35% has shifted to around 40% capacity factor for the 80% renewable hydrogen cases.

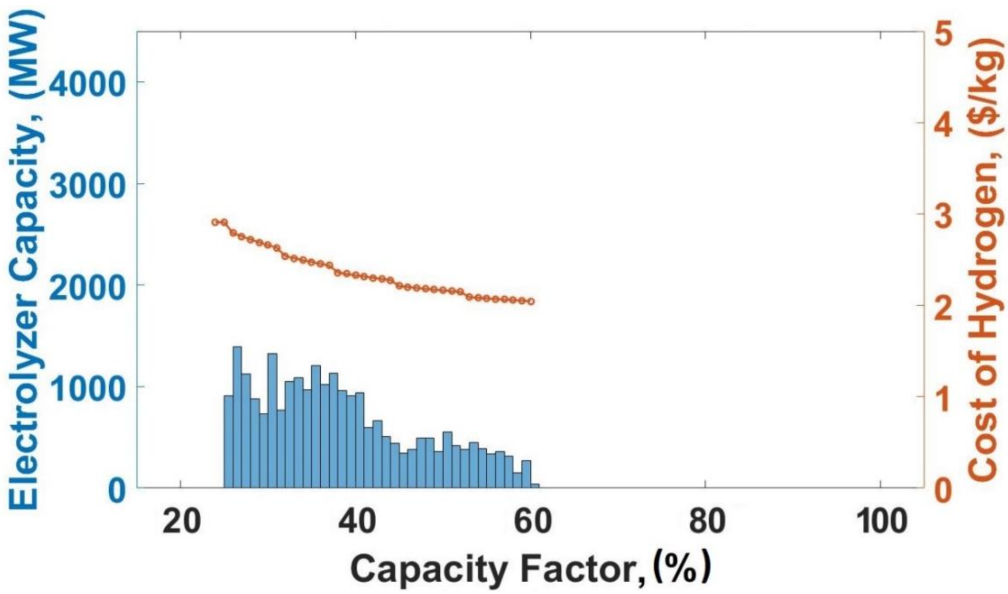

Figure 29: Electrolyzer capacity and cost of hydrogen of individual electrolyzers versus capacity factor at a renewable capacity of 147 GW, producing a minimum of 80% renewable hydrogen through centralized AEC plant with gaseous H_2 trucked to H_2 fueling station, pathway 13.

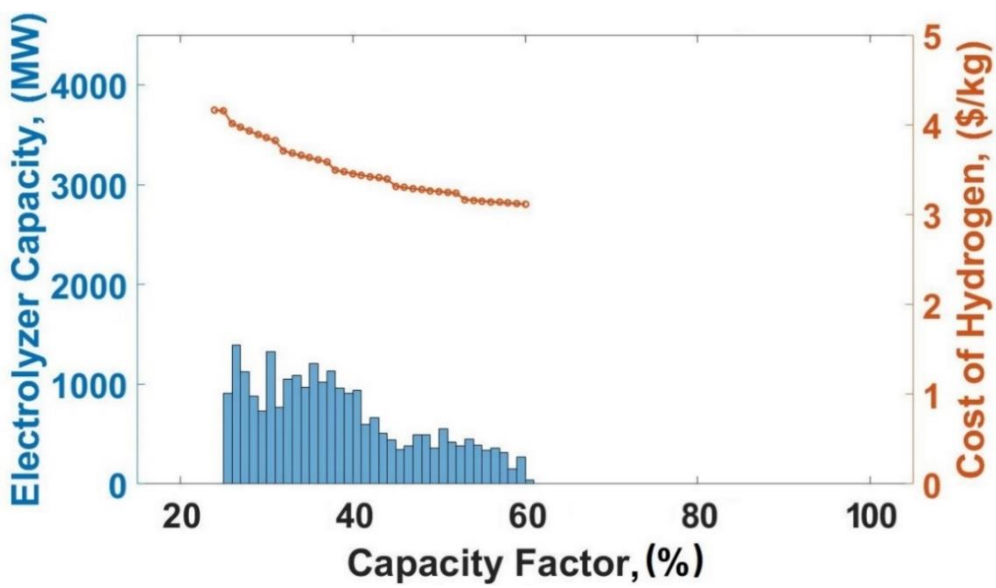

Figure 30: Electrolyzer capacity and cost of hydrogen of individual electrolyzers versus capacity factor at a renewable capacity of 147 GW, producing a minimum of 80% renewable hydrogen through centralized SOEC plant with gaseous H_2 trucked to H_2 fueling station, pathway 14.

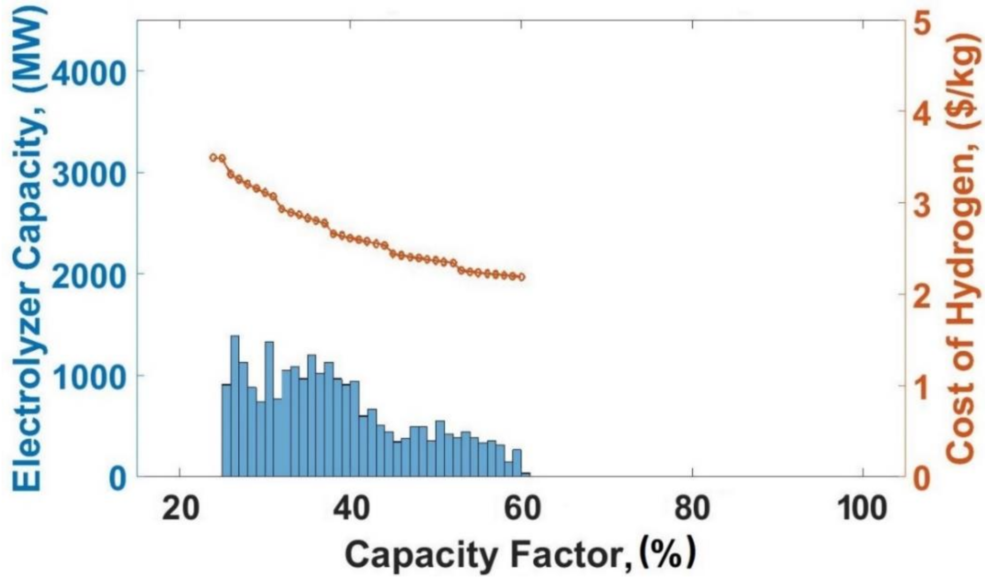

Figure 31: Electrolyzer capacity and cost of hydrogen of individual electrolyzers versus capacity factor at a renewable capacity of 147 GW, producing a minimum of 80% renewable hydrogen through centralized PEM plant with gaseous H_2 trucked to H_2 fueling station, pathway 15.

For a renewable capacity of 184 GW, the trends for the 80% renewable hydrogen are similar to those for the 147 GW renewable capacity. The increase in electrolyzer capacity of around 40% capacity factor is much more apparent in Figure 32 to Figure 34 than in Figure 29 to Figure 31. The capacity factor is also able to reach above 70% with higher renewable capacity due to the larger amount of available renewables. But, with a 40% increase in capacity factor from the 50% renewable hydrogen results, there was only a 20% decrease in costs. This may be due to the costs associated to the equipment and installation which is necessary regardless of capacity factor.

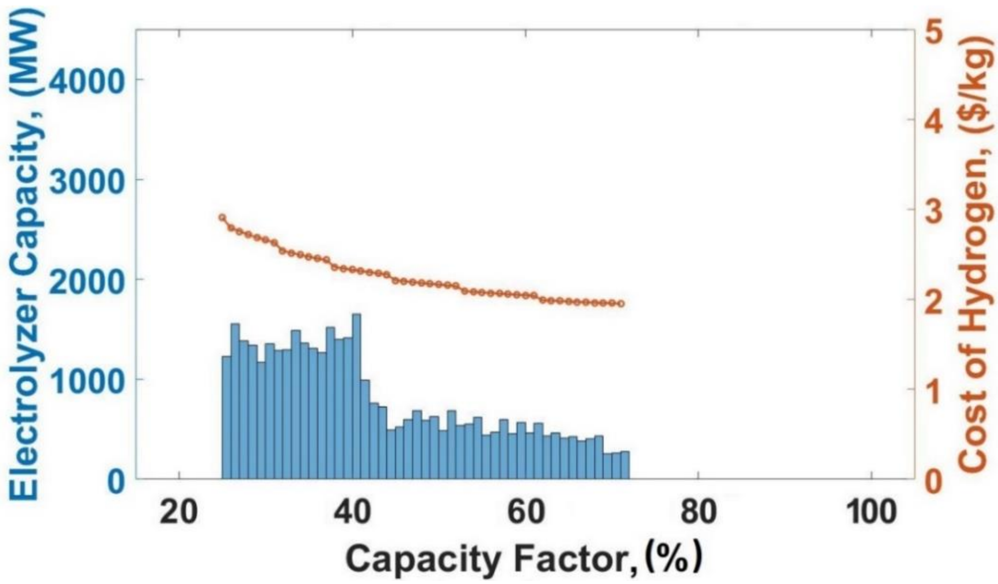

Figure 32: Electrolyzer capacity and cost of hydrogen of individual electrolyzers versus capacity factor at a renewable capacity of 184 GW, producing a minimum of 80% renewable hydrogen through centralized AEC plant with gaseous H_2 trucked to H_2 fueling station, pathway 13.

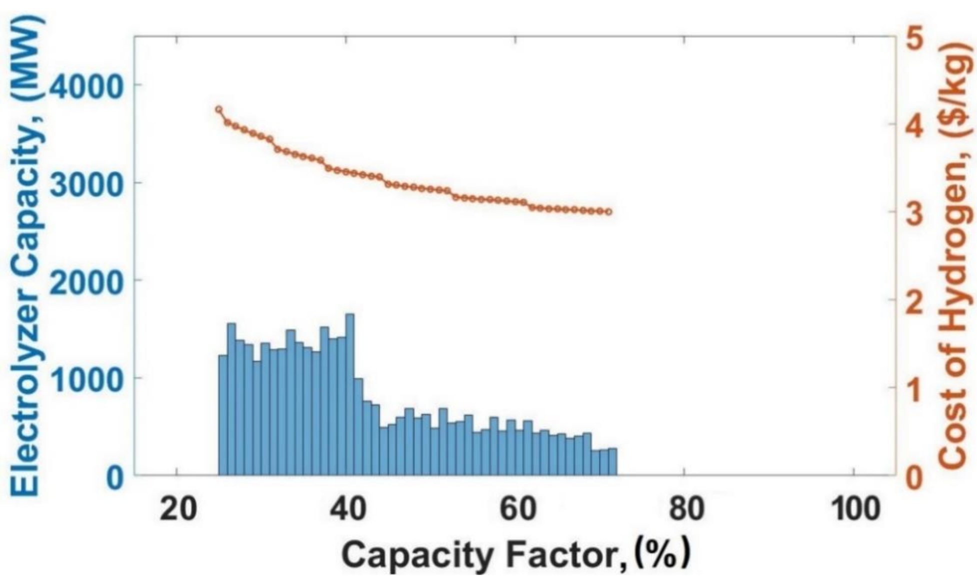

Figure 33: Electrolyzer capacity and cost of hydrogen of individual electrolyzers versus capacity factor at a renewable capacity of 184 GW, producing a minimum of 80% renewable hydrogen through centralized SOEC with gaseous H_2 trucked to H_2 fueling station, pathway 14.

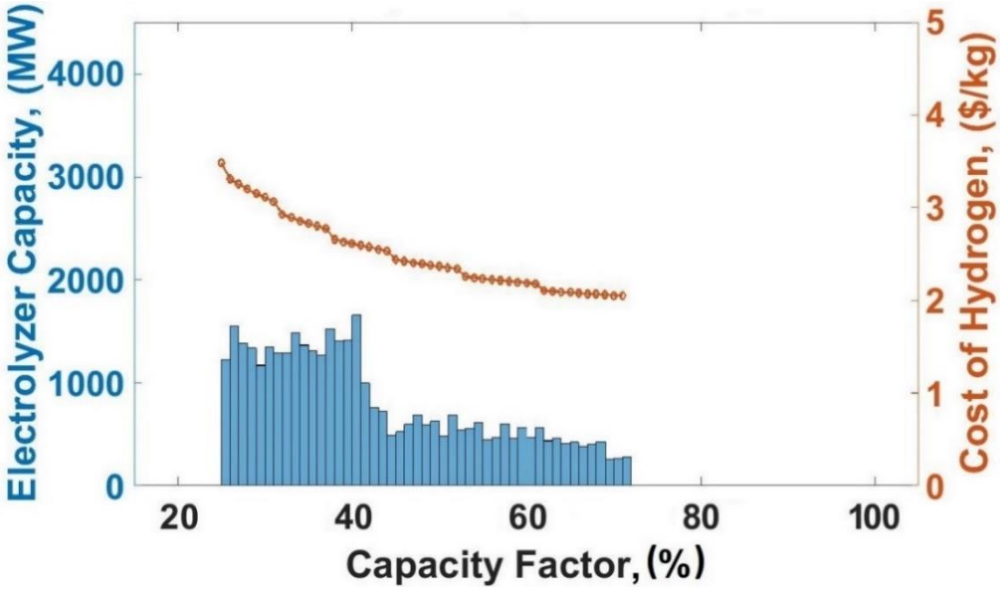

Figure 34: Electrolyzer capacity and cost of hydrogen of individual electrolyzers versus capacity factor at a renewable capacity of 184 GW, producing a minimum of 80% renewable hydrogen through centralized PEM plant with gaseous H_2 trucked to H_2 fueling station, pathway 15.

5.4.3 50% Renewable Hydrogen

At 50% renewable hydrogen, the electrolyzers are able to achieve extremely high capacity factors; with the high capacity factors cost of hydrogen lowers. The costs of hydrogen are able to reach below $2/kg, assuming no electricity feed costs, seen in Figure 35 to Figure 37. The electrolyzer capacity increase has shifted to around 65% capacity factor. Since the renewable hydrogen is set to be 50%, it is not limited to relying on otherwise curtailed renewable power which has peaks and variability. At a renewable capacity of 147 GW, the capacity factor reaches 100%. This is expected as in the 100% renewable hydrogen case the capacity factor is able to reach almost 50% and the 50% renewable hydrogen case is able to essentially double the capacity factor since only half of the electrolyzer is renewable.

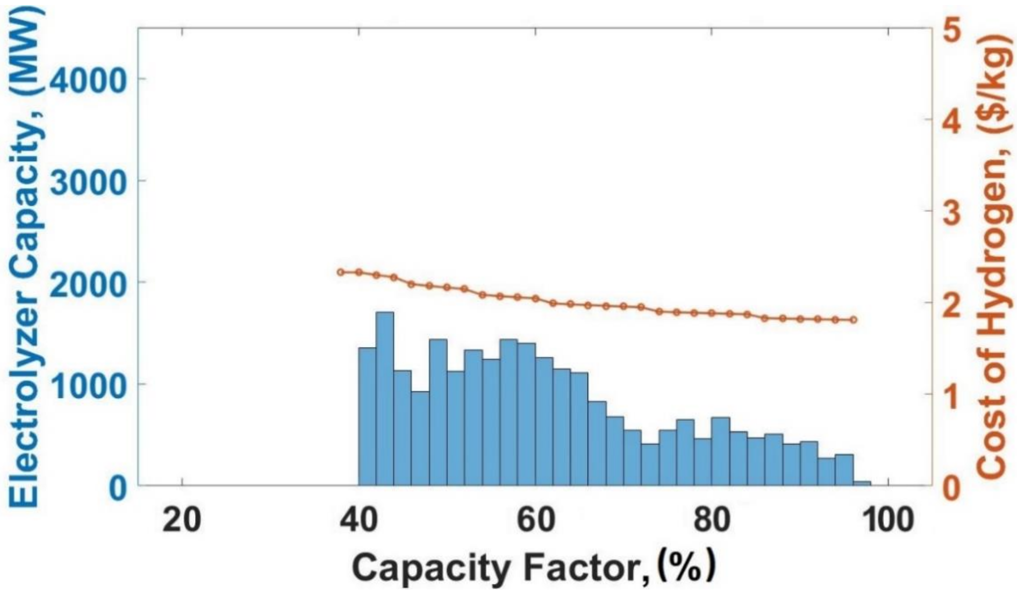

Figure 35: Electrolyzer capacity and cost of hydrogen of individual electrolyzers versus capacity factor at a renewable capacity of 147 GW, producing a minimum of 50% renewable hydrogen through centralized AEC plant with gaseous H_2 trucked to H_2 fueling station, pathway 13.

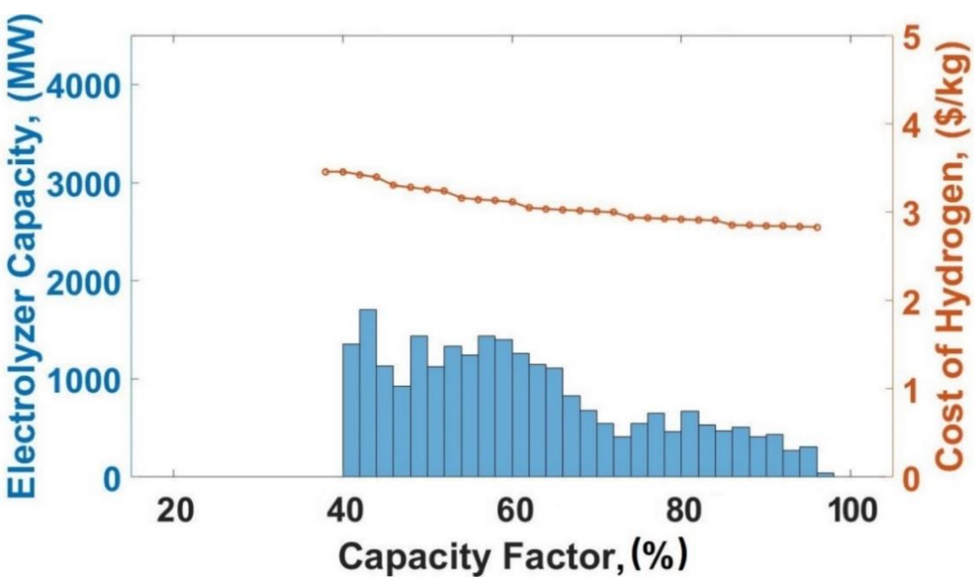

Figure 36: Electrolyzer capacity and cost of hydrogen of individual electrolyzers versus capacity factor at a renewable capacity of 147 GW, producing a minimum of 50% renewable hydrogen through centralized SOEC plant with gaseous H_2 trucked to H_2 fueling station, pathway 14.

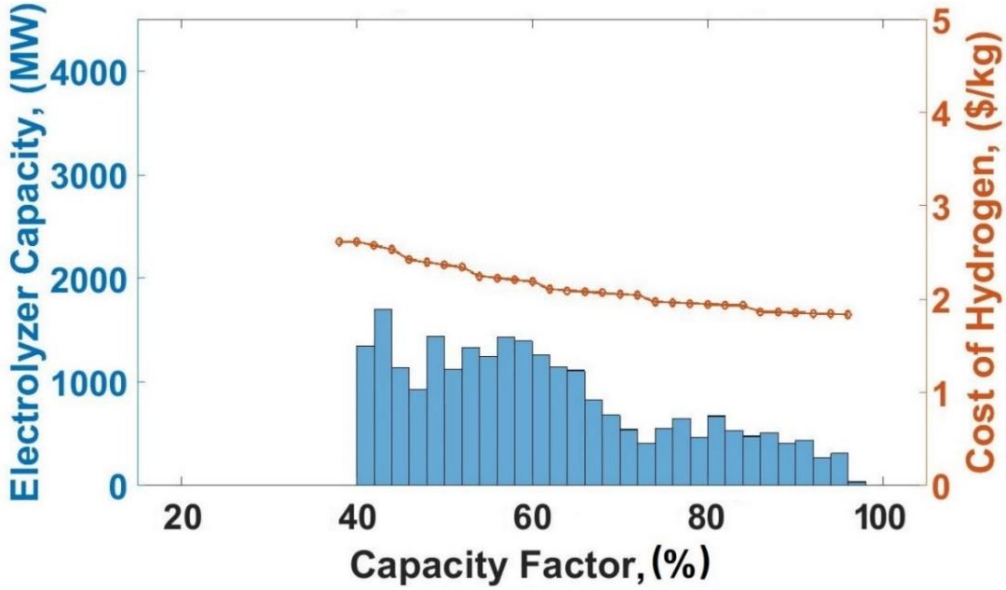

Figure 37: Electrolyzer capacity and cost of hydrogen of individual electrolyzers versus capacity factor at a renewable capacity of 147 GW, producing a minimum of 50% renewable hydrogen through centralized PEM plant with gaseous H_2 trucked to H_2 fueling station, pathway 15.

50% renewable hydrogen is only achievable at a certain nth electrolyzer at higher renewable capacity of 184 GW. Figure 38 shows that only starting at around the 4,500th electrolyzer can the electrolyzer reach the minimum of 50% renewable hydrogen. This plot is only necessary at 50% renewable hydrogen due some electrolyzers reaching a minimum renewable percentage higher than 50%. In other words, since there is high availability of otherwise curtailed renewable power the electrolyzer would need to be on all the time in order to reach a minimum percent of renewable hydrogen that's greater than 50%. Also, the 100% renewable hydrogen capacity factor is able to reach above 50%, close to 60%; this matches the minimum percent of renewable hydrogen shown in Figure 38.

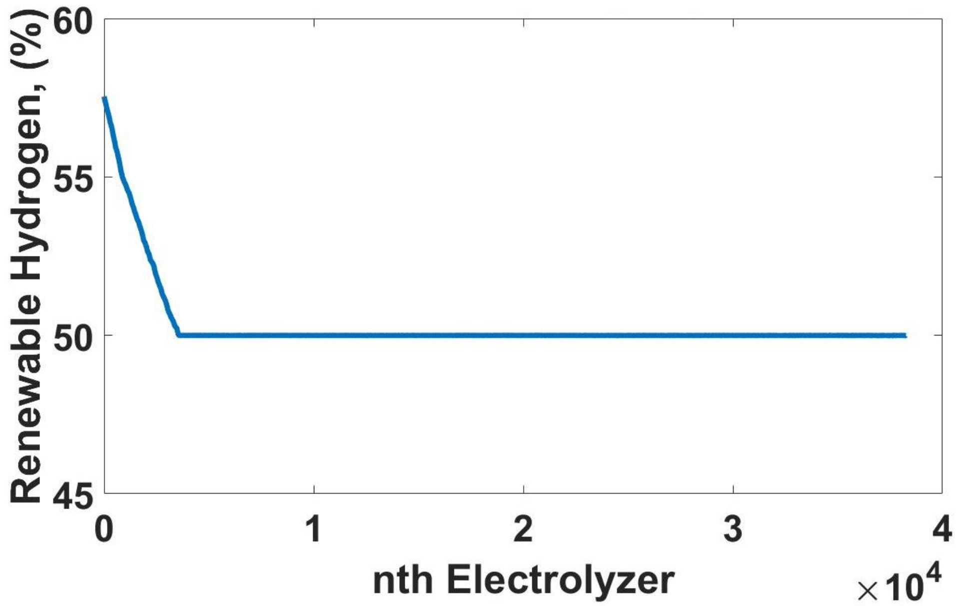

Figure 38: A plot, only seen for the 50% renewable hydrogen case, of the percent of renewable hydrogen from each individual electrolyzer at a renewable capacity of 184 GW.

Since the electrolyzers have a higher renewable percent of hydrogen than 50%, it's able to achieve high capacity factors, seen in Figure 39 to Figure 41. The electrolyzers that have a minimum renewable hydrogen percent greater than 50% are run at full capacity and are able to achieve capacity factors close to 100%. The cost of hydrogen is relatively constant at higher capacity factors despite doubling the capacity factor. Like the 80% renewable hydrogen results, this miniscule decrease in cost of hydrogen with large increase in capacity factor is due to the installation costs outweighing the operation and maintenance cost.

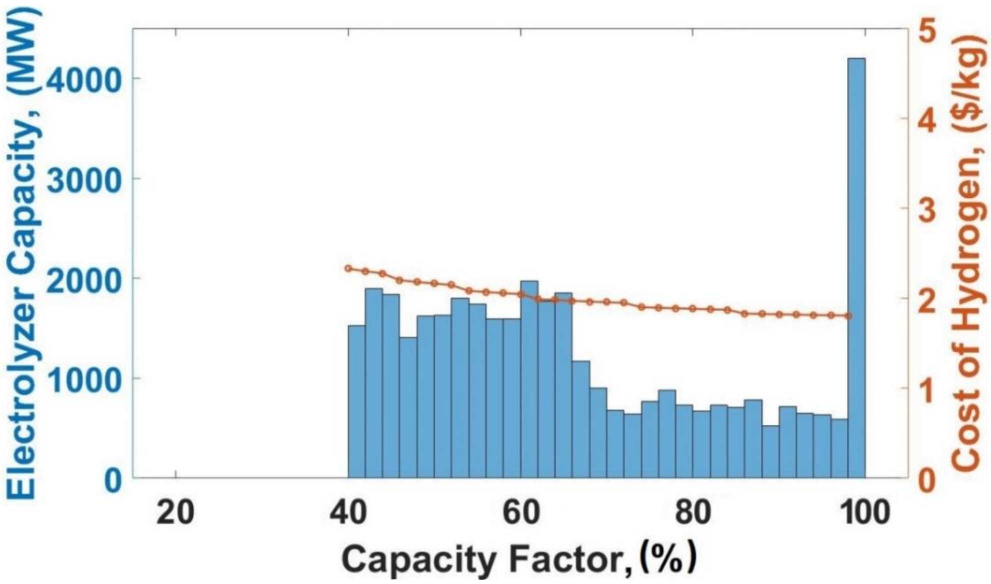

Figure 39: Electrolyzer capacity and cost of hydrogen of individual electrolyzers versus capacity factor at a renewable capacity of 184 GW, producing a minimum of 50% renewable hydrogen through centralized AEC plant with gaseous H_2 trucked to H_2 fueling station, pathway 13.

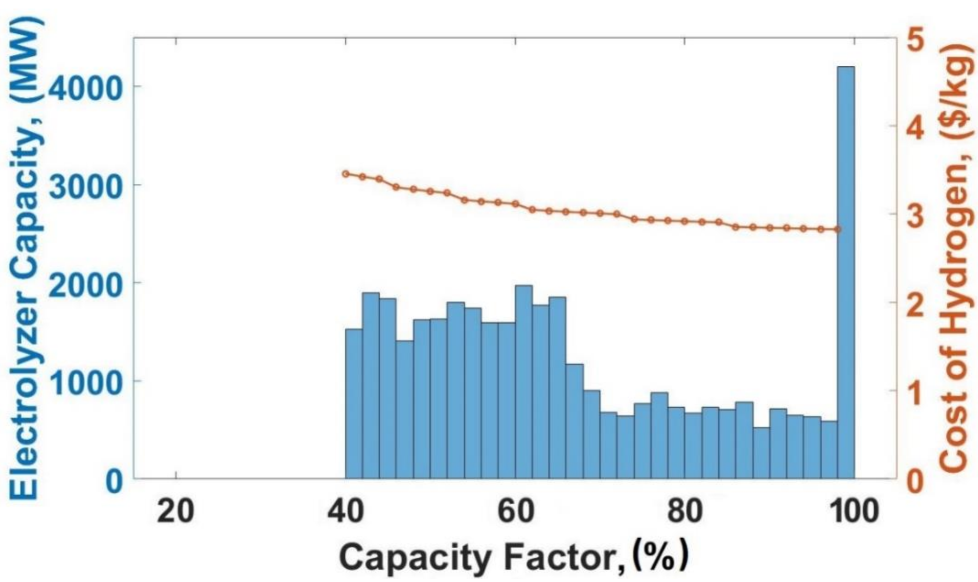

Figure 40: Electrolyzer capacity and cost of hydrogen of individual electrolyzers versus capacity factor at a renewable capacity of 184 GW, producing a minimum of 50% renewable hydrogen through centralized SOEC plant with gaseous H_2 trucked to H_2 fueling station, pathway 14.

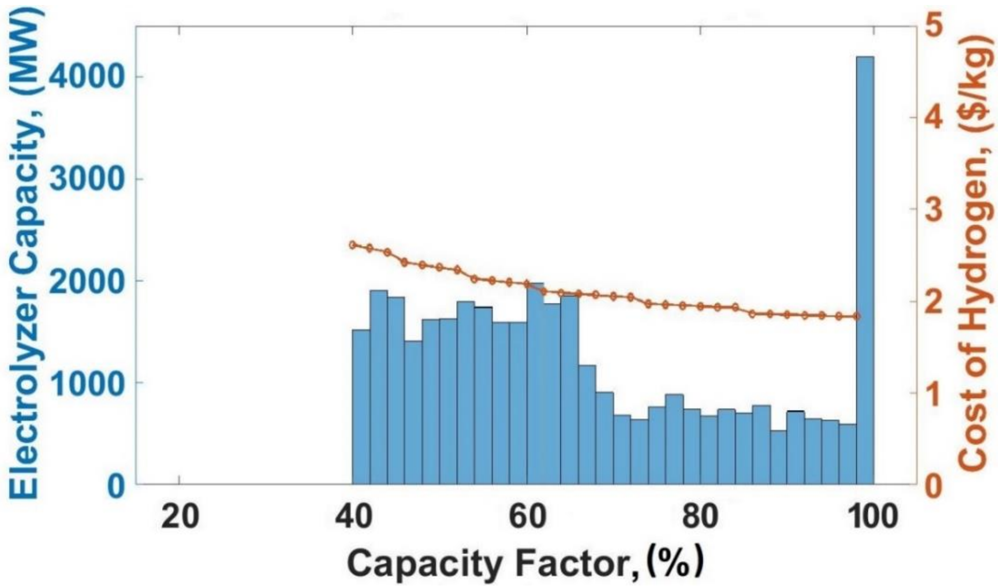

Figure 41: Electrolyzer capacity and cost of hydrogen of individual electrolyzers versus capacity factor at a renewable capacity of 184 GW, producing a minimum of 50% renewable hydrogen through centralized PEM plant with gaseous H_2 trucked to H_2 fueling station, pathway 15.

6 Summary

In this thesis, the operations of multiple P2G and energy storage pathways were applied for three different use cases: electric grid services as energy storage, renewable transportation fuel for FCVs, and renewable natural gas for natural gas type usage. In total, there are 37 different pathways within the three use cases which include a mixture of different technology types, such as a solid oxide or an alkaline electrolyzer, and different distribution methods, such as in pipelines or truck delivery. This allows a wide distribution of results which determine the effectiveness of the pathways' parameters, such as instant cost or heat rate, on both the electric grid as well as the levelized cost of energy for each use case. The CO_2 emission and the levelized cost of energy of the entire energy system provided a system perspective on the effectiveness of each pathway. The individual levelized cost of energy per pathway, such as the hydrogen produced by electrolyzers, provided a way of comparison between each pathway for the investor prospective.

The analysis was accomplished with the HiGRID model which simulates a year of operation of the California energy system as a whole. The operation of the energy storage use case is considered separately from the operation of the renewable transportation fuel and natural gas use case, due to the different operational methods. The energy storage use case work to balance the electric grid to reduce peaks and capture energy during high renewable energy generation. The renewable transportation fuel and natural gas use cases work to meet a demand of hydrogen which captures high renewable energy generation but does not reduce electricity demand peaks and offsets carbon emitting technologies without affecting the grid.

7 Conclusion

1. **Both CO_2 emissions and portfolio costs are reduced with implementation of Power-to-Gas and energy storage technologies compared to the base case.**

   Pathways in the renewable transportation fuel use case showed the most CO_2 reductions occurred by offsetting gasoline vehicles which have high CO_2 emissions. This is due to the California electric grid and natural gas system having less CO_2 emissions and emissions intensity than gasoline vehicles, so offsetting gasoline vehicles will result in the most CO_2 emission reductions. The CO_2 reduction reaches a maximum in the energy storage use cases, seen by the constant CO_2 reductions across multiple pathways, due to only offsetting an already relatively low CO_2 emission electric system. Also, imposing a capacity limitation on the P2G pathways also limits CO_2 reductions. The capacity limitation prevents the P2G pathways from fully utilizing curtailed power. The capacity will need to be capable of utilizing peak solar which will require a high capacity and result in a low capacity factor, which at best can only match that of solar.

   The LCOE reductions from the system perspective are less apparent than CO_2 emissions for the renewable transportation and renewable natural gas use cases since the use cases do not directly affect the electric grid, where most of the portfolio costs are from. The energy storage use case has a larger influence on the LCOE due to replacing other technologies such as load follower and peaker power plants. Without the capacity limitation the energy storage use cases display an increase in LCOE. This is due to the replacement of electricity production technologies, such as load follower and peaker power plants, with energy storage technologies which tend to be higher. The most reduction in LCOE is a mixture between hydrogen renewable gas and hydrogen ES. With a capacity limitation, the hydrogen renewable fuel has the most LCOE reduction; without a capacity limitation, hydrogen energy storage results in the most LCOE reduction.

2. **The Renewable Portfolio Standard has a high dependency on the capacity of the Power-to-Gas and energy storage technologies.**

   At limited capacities, the technologies cannot capture the otherwise curtailed peak solar power which limits the RPS. This can be seen when comparing the RPS between scenarios 1 and 3 to scenarios 2 and 4. Scenarios 1 and 3 did not have a limitation on capacity which results in a higher RPS; while scenarios 2 and 4 did have a limitation on capacity which resulted in a lower RPS. But, there is a case of RPS changing very little for the renewable fuel cases. This is due to the dependency on hydrogen demand as well as the capacity of the technologies. It is also seen, when spanning hydrogen demand and electrolyzer capacity, the capacity of the electrolyzers will need to be approximately two times larger than the required minimum in order to meet the hydrogen demand with otherwise curtailed power. And, the electrolyzer needs to be more than two times larger and the hydrogen demand must be large enough to capture the otherwise curtailed power in order to increase the RPS.

3. **The cost of energy of each individual pathway and use case has a dependence on the technology type and distribution methods.**

Each use case had different results, due to the different values of each energy type (MWh, kg, or MMBtu), but the different pathways within each use case differed slightly due to the differences in economics and efficiencies. Battery technology pathways displayed lowest energy costs with the ZnBr flow battery. This is due to the extremely low instant cost of the ZnBr flow battery as compared to all other battery technologies. The pathways which involved an electrolyzer had lowest costs with an alkaline electrolyzer, with the lowest instant cost, when considering little to no cost for electricity. Although, if the cost of electricity was high, solid oxide electrolyzers resulted in the lowest costs, due to the high efficiency through the usage of waste heat. For pathways with fuel cell technology, the solid oxide fuel cell resulted in the lowest energy costs. This is due to the low instant, operation, and maintenance costs of the solid oxide fuel cell.

The distribution methods of each pathway also had an effect for the costs of energy. For the renewable fuel use cases, the distribution system resulted in lower costs than the transmission system; this is due to the higher instant cost of transmission systems as opposed to distribution systems. The renewable transportation fuel use cases had lowest costs when gaseous hydrogen was trucked to fueling station rather than liquid hydrogen or onsite generation, due to the extra costs associated with distribution seen in Table 6.

4. **The cost of electricity and the operational methods, which correlate to capacity factor, of each pathway has a direct effect on the cost of energy.**

Regardless of the use case or pathway, the electricity cost will have an effect on the cost of energy. The electricity costs can be up to 30% of total costs when assuming costs of 1 cent/kWh. At high electricity costs, up to 30 cents/kWh, the electricity cost can account for over 90% of the total cost of energy. The cost of electricity accounts for a significant portion of the cost of energy and can be the deciding factor of whether the energy is cost competitive with other production methods. Only renewable H_2 into NG pipeline, renewable H_2 for transportation fuel, and battery energy storage use cases had potential for less cost of energy than current costs. Renewable CH_4 into NG pipeline and H_2 energy storage with no electricity costs had an energy cost greater than the current costs. The cost of electricity only has smaller effect on the cost of energy when the capacity factor is low. This is due to the technology not requiring as much electricity and the bulk of the costs come from the installation costs as the technology is larger than what is needed.

The capacity factor also has an effect on the cost of energy. For example, with decreasing capacity factor from 100% to 40% the cost of energy only increases by 25%, around \$2/kg H_2 to \$2.50/kg H_2. There is a 60% difference between capacity factors and only a 25% difference in costs of energy. This shows that allowing an electrolyzer to operate at capacity factors around 40% may be beneficial as increasing the capacity factors do not allow for a significant decrease in cost of energy but will allow the electrolyzers to match closer to renewable power.

Even though capacity factor has an effect on cost of electricity, it was found that most electrolyzers can operate at a wide range of capacity factors without dramatically increasing cost of energy when looking at individual electrolyzer cases. With 100% renewable hydrogen, only a few electrolyzers could achieve, at highest, a capacity factor of around

46% which resulted in the cost of hydrogen to be around $2.18/kg without the cost of electricity. But, more electrolyzers can operate at lower capacity factors. Approximately 67% of electrolyzers could operate at a capacity factor higher than 22%, which average cost of energy around $2.69, as opposed to only 3% of electrolyzers operating at capacity factors higher than 40%, which average cost of energy around $2.27/kg. There is a 2100% increase in number of electrolyzers and only a 19% increase in cost of energy when operating electrolyzers down to a capacity factor of 22% as opposed to capacity factors higher than 40%.

8 Future Work

8.1 Dynamic Economic Values

Currently, the economic values used in the HiGRID analysis are static and do not change with power capacity or fleet size. This will have an effect in costs when spanning different capacities and sizes at different years in order to help understand the progression of the use cases instead of just the potential future. The integration of the Economic Model presented in the P2G report into the Cost Module in HiGRID will be required to expand the capabilities.

8.2 Electric Vehicle Comparison

Comparing economics of electric vehicles (EVs) is important in order to understand the technology competing with FCVs. Economic values of EV infrastructure and charging stations would be needed in order to conduct this comparison. EVs add significant amount of demand to the electric grid and have implications with time of charging. FCVs have the ability to decouple fueling and production of fuel while EVs do not. But, EVs have higher efficiencies than FCVs. Both technologies have pros and cons; it will be interesting to compare both technologies with an economic evaluation of the effects to the electric grid.

Some preliminary results for a comparison between EV charging versus production of hydrogen for FCVs were completed. The EVs have different charging scenarios: immediate (charging immediately when the battery runs low) and smart charging (charging during times of high renewable power). Different levels of charging were considered, shown in Table 24.

Table 24: Different charging types and the associated charging speed for EVs.

Charging type	Charging Speed (kW)
Level III	50
Level II	3.6
Level I	1

Figure 42 shows the CO_2 reduction vs LCOE change for immediate and smart charging EV and FCVs, repeating the results for FCVs from Figure 13. It can be seen that the EVs have a much higher potential for CO_2 reduction and LCOE than FCVs, this is due to the higher efficiency and being able to travel more miles than FCVs, reducing more emissions from gasoline vehicles. But, the RPS for the EV cases were much lower than the FCV cases, seen in Figure 43. The positive values for RPS denote an increase in RPS while the negative values denote a decrease. The positive values for Levelized Cost of Energy Change denote a decrease while the negative values denote an increase. All in all, a positive value in the plot represents a better case than the base case. The RPS is lower for EV cases due to the effects of charging on the electric grid. With immediate charging, the RPS is much lower due to the mismatch between charging patterns and renewable energy generation. Smart charging has slightly higher RPS than immediate charging, but is still less than the base case.

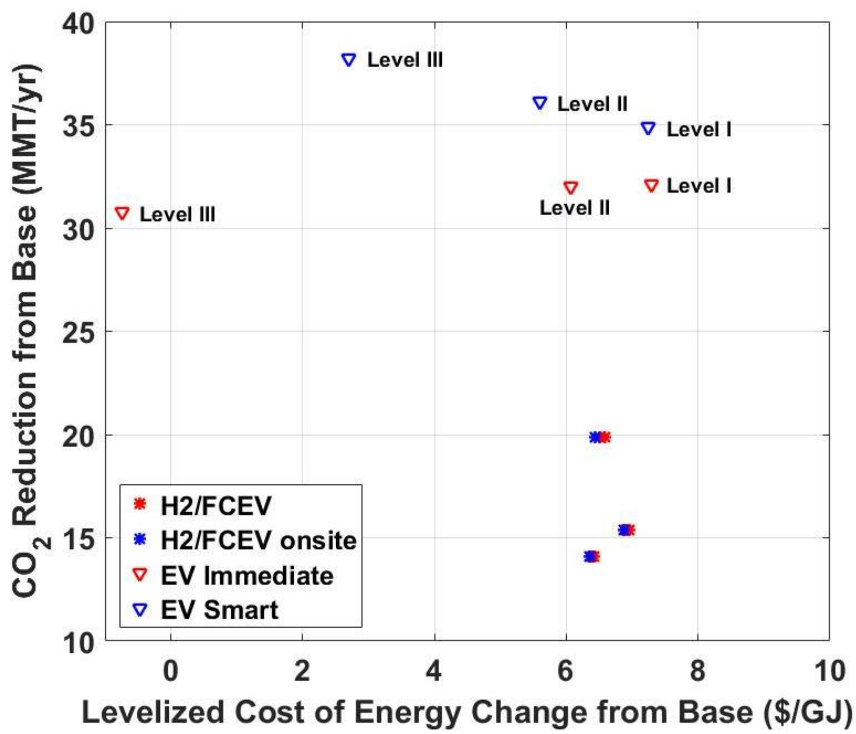

Figure 42: CO2 reduction versus LCOE, comparing EV and FCV cases.

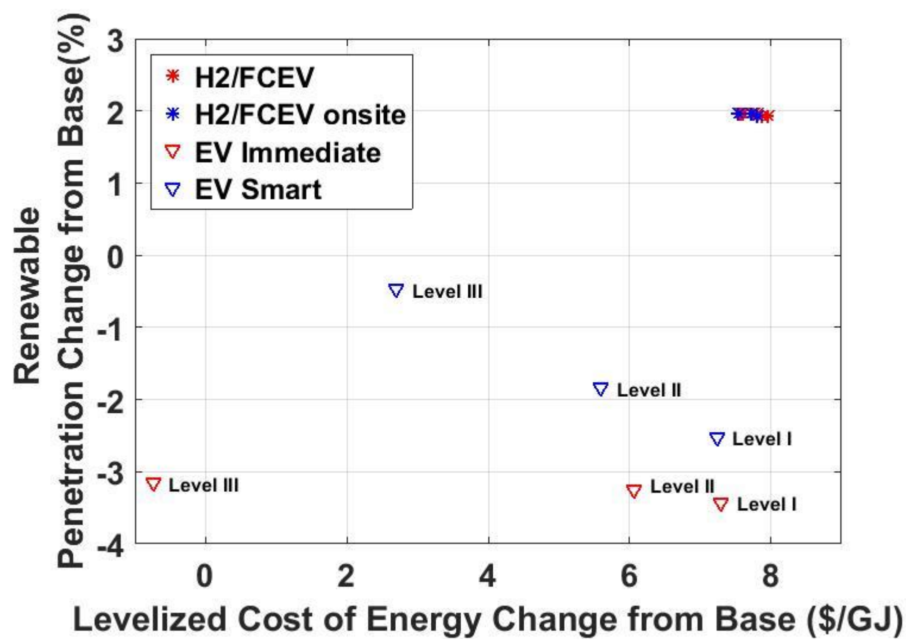

Figure 43: RPS versus LCOE change from base, comparing EV and FCV cases.

It should be noted that no cases for vehicle to grid cases were conducted. Vehicle grid allows for vehicles to become more integrated to the electric grid as grid operators could both charge to and discharge from the EVs in order to balance the grid. These cases should be conducted in the future in order to obtain a fair comparison between FCVs and EVs.

8.3 Percent of Hydrogen in Natural Gas Pipeline

The percent of natural gas was found to be well below the recommended 20% by volume maximum. But, this was calculated by total volume of hydrogen over total volume of natural gas in the energy system. This is not the actual volume of hydrogen in the pipelines. The volume percent would be dependent on both location and time. For example, if all the hydrogen was produced only in Tehachapi and injected directly into the natural gas pipeline after production the percent by volume of hydrogen in the natural gas system could exceed 20%. The hydrogen injection must be distributed throughout the whole system and must be controlled in order to ensure a safe practice. More research would be required to better understand the natural gas system of California, spatial and temporal operation of natural gas would be required.

8.4 Comparing Each Electrolyzer Pathway

Looking into the each pathway could be easily conducted for all the electrolyzer pathways, 1 to 21, instead of just pathways 13 to 15. The overall trends should still look the same as the operation of each pathway is similar, differentiating only by efficiency and economic values. The individual electrolyzers could also be considered for the H_2 energy storage use cases, but will require more change within HiGRID. Currently, the H_2 energy storage is assumed to operate similarly to an electric battery instead of a separate electrolyzer and fuel cell. A new module would be needed in order to run H_2 energy storage as a separate electrolyzer and fuel cell.

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10 Appendix

10.1 Sample of Individual Pathway Economic Parameters[2]

Table 25: The economic parameters of use case 1 to 4.

Pathway Number	Instant Cost ($/kW)	Fixed Operation and Maintenance Cost ($/kW-yr)	Variable Operation and Maintenance Cost ($/kW-yr)	Heat Rate (MWh_{in} / MWh_{out})
1	289.62	10.43	1.24	1.17
2	466.60	15.40	13.00	0.89
3	398.30	14.32	0.17	1.28
4	322.36	10.43	1.24	1.17
5	499.34	15.40	13.00	0.89
6	431.04	14.32	0.17	1.28
7	489.45	13.76	1.57	1.50
8	788.55	20.32	16.39	1.14
9	673.13	18.91	0.22	1.64
10	522.19	13.76	1.57	1.50
11	821.29	20.32	16.39	1.14
12	705.87	18.91	0.22	1.64

[2] These economic parameters were compiled by Lori Schell.

Table 26: The economic parameters of use case 5 to 7.

Pathway Number	Instant Cost (\$/kW)	Fixed Operation and Maintenance Cost (\$/kW-yr)	Variable Operation and Maintenance Cost (\$/kW-yr)	Heat Rate (MWh_{in} / MWh_{out})
13	289.62	10.43	1.24	1.17
14	466.60	15.40	13.00	0.89
15	398.30	14.32	0.17	1.28
16	289.62	10.43	1.24	1.17
17	466.60	15.40	13.00	0.89
18	398.30	14.32	0.17	1.28
19	289.62	10.43	1.24	1.17
20	466.60	15.40	13.00	0.89

Table 27: The economic parameters of use case 8 and 9.

Pathway Number	Instant Cost (\$/kW)	Fixed Operation and Maintenance Cost (\$/kW-yr)	Variable Operation and Maintenance Cost (\$/kW-yr)	Heat Rate (MWh_{in} / MWh_{out})
21	2223.50	53.07	15.69	2.16
22	2367.43	55.95	34.44	1.65
23	2538.42	64.37	13.41	2.36
24	2922.15	67.08	10.61	2.16
25	3066.07	69.95	29.36	1.65
26	3236.63	78.37	8.33	2.36
27	2137.21	51.38	7.82	2.16
28	2281.13	54.25	26.57	1.65
29	2451.69	62.67	5.54	2.36
30	1958.53	47.81	5.27	2.16
31	2102.45	50.67	24.02	1.65
32	2273.01	59.10	2.99	2.36
33	312.44	77.65	0.61	1.54
34	1327.87	307.78	2.78	1.11
35	2000.75	101.42	0.63	1.12
36	2524.35	4.86	0.47	1.33

10.2 Individual Pathway Economic Results

10.2.1Portfolio Cost Results

Table 28: The energy costs of use case 1 to 4 with Portfolio electricity costs.

Pathway Number	$/MMBtu				$/GJ			
Scenarios:	1	2	3	4	1	2	3	4
1	137.23	108.73	146.05	122.22	130.37	103.29	138.75	116.11
2	125.10	90.64	129.57	99.61	118.84	86.10	123.09	94.63
3	164.01	121.23	171.19	134.50	155.81	115.16	162.63	127.77
4	140.03	108.99	148.05	121.17	133.03	103.54	140.64	115.11
5	127.12	90.68	130.98	98.81	120.77	86.14	124.43	93.87
6	167.12	121.54	173.46	133.80	158.76	115.46	164.78	127.11
7	191.31	135.32	197.20	148.58	181.75	128.55	187.34	141.15
8	184.18	116.27	183.90	123.56	174.98	110.46	174.70	117.38
9	237.00	152.96	238.63	164.56	225.15	145.31	226.70	156.34
10	194.75	135.65	199.66	147.35	185.01	128.87	189.68	139.98
11	186.68	116.34	185.64	122.61	177.35	110.52	176.36	116.48
12	240.81	153.35	241.42	163.75	228.77	145.68	229.35	155.56

Table 29: The energy costs of use case 5 to 7 with Portfolio electricity costs.

Pathway Number	$/kg H2				$/GJ			
Scenarios:	1	2	3	4	1	2	3	4
13	19.74	15.92	20.92	17.73	139.82	112.73	148.19	125.55
14	18.53	13.90	19.13	15.11	131.22	98.48	135.47	107.01
15	23.22	17.48	24.18	19.26	164.47	123.82	171.29	136.43
16	19.97	16.15	21.15	17.96	141.45	114.37	149.82	127.18
17	18.83	14.21	19.43	15.41	133.36	100.62	137.61	109.15
18	23.43	17.69	24.40	19.47	165.96	125.31	172.78	137.92
19	20.13	16.30	21.31	18.11	142.54	115.46	150.91	128.27
20	19.03	14.41	19.63	15.61	134.79	102.05	139.04	110.58

Table 30: The energy costs of use case 8 and 9 with Portfolio electricity costs.

Pathway Number	$/MWh				$/GJ			
Scenarios:	1	2	3	4	1	2	3	4
21	1057.04	565.53	1145.74	605.85	294.31	157.46	319.01	168.69
22	1144.42	608.91	1236.32	646.52	318.64	169.54	344.23	180.01
23	1238.47	629.32	1334.56	663.81	344.83	175.22	371.58	184.82
24	1297.33	638.44	1401.42	672.01	361.21	177.76	390.20	187.11
25	1387.42	682.79	1494.15	713.25	386.30	190.11	416.02	198.59
26	1495.87	709.93	1607.81	736.90	416.49	197.66	447.66	205.18
27	1026.44	550.24	1114.01	591.54	285.79	153.20	310.17	164.70
28	1114.30	593.84	1205.17	632.46	310.25	165.34	335.55	176.09
29	1207.54	613.71	1302.53	649.23	336.22	170.88	362.66	180.76
30	952.07	523.02	1035.10	565.92	265.09	145.62	288.20	157.57
31	1038.57	566.08	1124.99	606.43	289.17	157.61	313.23	168.85
32	1127.17	583.94	1217.41	621.31	313.84	162.59	338.96	172.99
33	507.49	387.12	565.18	448.46	141.30	107.78	157.36	124.86
34	1056.44	575.01	1140.66	628.51	294.14	160.10	317.59	175.00
35	883.97	514.33	965.06	570.62	246.12	143.20	268.70	158.88
36	932.96	560.10	1011.79	617.90	259.76	155.95	281.71	172.04
37	1057.04	565.53	1145.74	605.85	294.31	157.46	319.01	168.69

10.2.23 cents/kWh Cost Results

Table 31: The energy costs of use case 1 to 4 with 3cents/kWh electricity costs.

Pathway Number	$/MMBtu				$/GJ			
Scenarios:	1	2	3	4	1	2	3	4
1	49.64	21.10	43.69	17.50	47.16	20.04	41.51	16.63
2	58.30	23.83	51.56	19.81	55.38	22.64	48.98	18.82
3	68.41	25.58	59.49	20.18	64.99	24.30	56.51	19.17
4	52.86	21.77	46.38	17.85	50.21	20.68	44.06	16.96
5	60.75	24.33	53.61	20.07	57.71	23.12	50.93	19.06
6	71.92	26.31	62.42	20.57	68.32	25.00	59.30	19.54
7	87.13	31.09	75.45	24.03	82.77	29.54	71.68	22.83
8	104.73	36.81	91.11	28.64	99.50	34.97	86.56	27.20
9	123.28	39.20	105.76	28.60	117.12	37.24	100.48	27.17
10	91.07	31.91	78.75	24.46	86.52	30.32	74.81	23.24
11	107.73	37.43	93.61	28.95	102.35	35.56	88.93	27.51
12	127.58	40.09	109.36	29.07	121.20	38.09	103.89	27.62

Table 32: The energy costs of use case 5 to 7 with 3cents/kWh electricity costs.

Pathway Number	$/kg H2				$/GJ			
Scenarios:	1	2	3	4	1	2	3	4
13	7.99	4.16	7.19	3.68	56.60	29.48	50.95	26.07
14	9.57	4.94	8.66	4.40	67.76	35.01	61.36	31.19
15	10.40	4.65	9.20	3.93	73.64	32.95	65.16	27.83
16	8.22	4.39	7.42	3.91	58.23	31.12	52.59	27.70
17	9.87	5.25	8.97	4.71	69.90	37.15	63.50	33.33
18	10.61	4.86	9.41	4.14	75.14	34.45	66.66	29.32
19	8.38	4.55	7.58	4.07	59.32	32.21	53.67	28.79
20	10.07	5.45	9.17	4.91	71.33	38.58	64.93	34.76

Table 33: The energy costs of use case 8 and 9 with 3cents/kWh electricity costs.

Pathway Number	$/MWh				$/GJ			
Scenarios:	1	2	3	4	1	2	3	4
21	860.88	315.64	910.98	293.69	239.69	87.88	253.64	81.77
22	948.68	359.33	1002.17	334.61	264.14	100.05	279.03	93.17
23	1044.87	381.11	1104.34	352.92	290.92	106.11	307.48	98.26
24	1101.17	388.55	1166.66	359.86	306.60	108.18	324.83	100.19
25	1191.69	433.21	1260.01	401.35	331.80	120.62	350.82	111.75
26	1302.28	461.72	1377.58	426.01	362.59	128.56	383.56	118.61
27	829.07	298.79	877.80	277.44	230.84	83.19	244.40	77.25
28	917.35	342.71	969.57	318.62	255.42	95.42	269.96	88.71
29	1012.75	363.97	1070.87	336.40	281.98	101.34	298.16	93.66
30	755.67	272.82	800.05	253.38	210.40	75.96	222.76	70.55
31	842.59	316.19	890.56	294.14	234.60	88.04	247.96	81.90
32	933.33	335.43	986.90	310.03	259.87	93.39	274.78	86.32
33	275.35	125.30	285.24	120.00	76.66	34.89	79.42	33.41
34	808.99	308.65	833.66	295.42	225.25	85.94	232.12	82.25
35	637.02	248.18	658.44	237.69	177.37	69.10	183.33	66.18
36	678.81	280.35	704.06	267.50	189.00	78.06	196.03	74.48
37	860.88	315.64	910.98	293.69	239.69	87.88	253.64	81.77

10.2.31 cent/kWh Cost Results

Table 34: The energy costs of use case 1 to 4 with 1 cent/kWh electricity costs.

Pathway Number	$/MMBtu				$/GJ			
Scenarios:	1	2	3	4	1	2	3	4
1	40.97	12.42	35.02	8.83	38.92	11.80	33.27	8.39
2	51.68	17.21	44.94	13.19	49.10	16.35	42.70	12.53
3	58.94	16.12	50.02	10.72	56.00	15.31	47.52	10.18
4	44.18	13.10	37.71	9.18	41.98	12.44	35.82	8.72
5	54.13	17.72	46.99	13.45	51.42	16.83	44.64	12.78
6	62.45	16.85	52.95	11.10	59.33	16.01	50.31	10.55
7	76.81	20.78	65.14	13.71	72.97	19.74	61.88	13.03
8	96.86	28.94	83.24	20.76	92.02	27.49	79.08	19.73
9	112.02	27.94	94.51	17.34	106.42	26.54	89.78	16.48
10	80.75	21.60	68.43	14.14	76.72	20.52	65.01	13.44
11	99.86	29.56	85.74	21.08	94.87	28.08	81.46	20.03
12	116.32	28.84	98.10	17.81	110.51	27.39	93.19	16.92

Table 35: The energy costs of use case 5 to 7 with 1 cent/kWh electricity costs.

Pathway Number	$/kg H2				$/GJ			
Scenarios:	1	2	3	4	1	2	3	4
13	6.83	3.00	6.03	2.52	48.36	21.25	42.71	17.83
14	8.68	4.06	7.78	3.52	61.47	28.72	55.07	24.90
15	9.13	3.38	7.93	2.66	64.65	23.96	56.17	18.84
16	7.06	3.23	6.26	2.75	49.99	22.88	44.35	19.46
17	8.98	4.36	8.08	3.82	63.61	30.87	57.21	27.05
18	9.34	3.59	8.14	2.87	66.15	25.46	57.67	20.33
19	7.21	3.38	6.42	2.90	51.08	23.97	45.44	20.55
20	9.18	4.56	8.28	4.02	65.04	32.29	58.64	28.47

Table 36: The energy costs of use case 8 and 9 with 1 cent/kWh electricity costs.

Pathway Number	$/MWh				$/GJ			
Scenarios:	1	2	3	4	1	2	3	4
21	836.18	290.95	886.29	268.99	232.82	81.01	246.77	74.90
22	923.99	334.63	977.48	309.91	257.27	93.17	272.16	86.29
23	1020.18	356.42	1079.64	328.22	284.05	99.24	300.60	91.39
24	1076.47	363.85	1141.96	335.16	299.72	101.31	317.96	93.32
25	1166.99	408.51	1235.31	376.65	324.92	113.74	343.95	104.87
26	1277.58	437.02	1352.88	401.32	355.71	121.68	376.68	111.74
27	804.22	273.94	852.95	252.59	223.92	76.27	237.49	70.33
28	892.50	317.86	944.72	293.77	248.50	88.50	263.04	81.79
29	987.90	339.12	1046.02	311.55	275.06	94.42	291.24	86.75
30	730.94	248.09	775.32	228.65	203.52	69.08	215.87	63.66
31	817.86	291.47	865.83	269.41	227.72	81.15	241.07	75.01
32	908.61	310.70	962.17	285.30	252.98	86.51	267.90	79.44
33	250.65	100.60	260.54	95.30	69.79	28.01	72.54	26.53
34	784.29	283.95	808.97	270.72	218.37	79.06	225.24	75.38
35	612.33	223.49	633.75	213.00	170.49	62.23	176.45	59.30
36	652.69	254.23	677.93	241.37	181.73	70.78	188.76	67.21
37	836.18	290.95	886.29	268.99	232.82	81.01	246.77	74.90

10.2.4 No Electricity Cost Results

Table 37: The energy costs of use case 1 to 4 with no electricity costs.

Pathway Number	$/MMBtu				$/GJ			
Scenarios:	1	2	3	4	1	2	3	4
1	36.63	8.09	30.68	4.49	34.80	7.68	29.15	4.27
2	48.37	13.90	41.64	9.88	45.95	13.21	39.55	9.39
3	54.21	11.38	45.29	5.99	51.50	10.81	43.02	5.69
4	39.85	8.76	33.37	4.84	37.86	8.32	31.70	4.60
5	50.82	14.41	43.68	10.14	48.28	13.69	41.50	9.63
6	57.72	12.12	48.22	6.37	54.84	11.51	45.81	6.05
7	71.65	15.62	59.98	8.56	68.07	14.84	56.98	8.13
8	92.93	25.00	79.30	16.83	88.28	23.75	75.34	15.99
9	106.40	22.31	88.88	11.71	101.08	21.19	84.43	11.13
10	75.60	16.44	63.27	8.99	71.82	15.62	60.11	8.54
11	95.93	25.62	81.81	17.15	91.13	24.34	77.72	16.29
12	110.70	23.21	92.47	12.18	105.16	22.05	87.85	11.57

Table 38: The energy costs of use case 5 to 7 with no electricity costs.

Pathway Number	$/kg H2				$/GJ			
Scenarios:	1	2	3	4	1	2	3	4
13	6.25	2.42	5.45	1.94	44.24	17.13	38.59	13.71
14	8.24	3.61	7.33	3.07	58.33	25.58	51.93	21.76
15	8.49	2.75	7.30	2.02	60.15	19.47	51.68	14.34
16	6.48	2.65	5.68	2.17	45.87	18.76	40.23	15.34
17	8.54	3.91	7.63	3.37	60.47	27.72	54.07	23.90
18	8.70	2.96	7.51	2.24	61.65	20.96	53.17	15.84
19	6.63	2.80	5.83	2.32	46.96	19.85	41.32	16.43
20	8.74	4.12	7.84	3.58	61.90	29.15	55.50	25.33

Table 39: The energy costs of use case 8 and 9 with no electricity costs.

Pathway Number	$/MWh				$/GJ			
Scenarios:	1	2	3	4	1	2	3	4
21	823.83	278.60	873.94	256.65	229.38	77.57	243.33	71.46
22	911.64	322.28	965.13	297.56	253.83	89.73	268.72	82.85
23	1007.83	344.07	1067.29	315.87	280.61	95.80	297.16	87.95
24	1064.13	351.50	1129.61	322.81	296.28	97.87	314.52	89.88
25	1154.64	396.16	1222.96	364.30	321.49	110.30	340.51	101.43
26	1265.23	424.68	1340.53	388.97	352.28	118.24	373.24	108.30
27	791.79	261.52	840.52	240.17	220.46	72.81	234.03	66.87
28	880.08	305.44	932.30	281.34	245.04	85.04	259.58	78.33
29	975.47	326.69	1033.59	299.13	271.60	90.96	287.78	83.29
30	718.58	235.73	762.95	216.29	200.07	65.63	212.43	60.22
31	805.50	279.10	853.47	257.04	224.27	77.71	237.63	71.57
32	896.24	298.34	949.81	272.94	249.54	83.07	264.45	75.99
33	238.30	88.26	248.19	82.95	66.35	24.57	69.10	23.10
34	771.94	271.60	796.62	258.38	214.93	75.62	221.80	71.94
35	599.98	211.14	621.40	200.65	167.05	58.79	173.01	55.87
36	639.62	241.16	664.87	228.31	178.09	67.15	185.12	63.57
37	823.83	278.60	873.94	256.65	229.38	77.57	243.33	71.46

10.3 Each pathway CO_2 emission results

Table 40: The CO_2 emissions of use case 1 to 4.

Pathway Number	Million Tons of CO_2			
Scenarios:	1	2	3	4
1	146.78	146.90	136.38	142.46
2	145.59	145.72	135.04	141.07
3	147.17	147.29	137.02	143.07
4	147.12	147.26	136.82	142.99
5	146.03	146.17	135.61	141.75
6	147.48	147.62	137.43	143.55
7	147.88	148.00	138.16	144.14
8	147.04	147.16	137.37	143.27
9	148.18	148.30	138.65	144.60
10	148.22	148.37	138.59	144.66
11	147.48	147.62	137.94	143.95
12	148.50	148.64	139.05	145.08

Table 41: The CO_2 emissions of use case 5 to 7.

Pathway Number	$/kg H2			
Scenarios:	1	2	3	4
13	136.10	136.24	119.25	126.28
14	131.60	131.75	112.60	119.86
15	137.39	137.53	121.33	128.24
16	136.10	136.24	119.25	126.28
17	131.60	131.75	112.60	119.86
18	137.39	137.53	121.33	128.24
19	136.10	136.24	119.25	126.28
20	131.60	131.75	112.60	119.86

Table 42: The CO_2 emissions of use case 8 and 9.

Pathway Number	$/MWh			
Scenarios:	1	2	3	4
21	133.14	148.26	127.51	139.14
22	135.02	148.45	130.11	139.24
23	136.07	149.44	127.53	140.12
24	133.14	148.26	127.51	139.14
25	135.02	148.45	130.11	139.24
26	136.07	149.44	127.53	140.12
27	133.14	148.26	127.51	139.14
28	135.02	148.45	130.11	139.24
29	136.07	149.44	127.53	140.12
30	133.14	148.26	127.51	139.14
31	135.02	148.45	130.11	139.24
32	136.07	149.44	127.53	140.12
33	132.94	143.11	127.67	137.51
34	128.80	140.59	127.58	135.69
35	128.90	140.69	127.62	135.77
36	131.18	142.43	127.60	137.07
37	133.14	148.26	127.51	139.14