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UNIVERSITY OF CALIFORNIA,
IRVINE

Use of Excess Renewable Electricity Generation to meet Future California Stated System Goals

DISSERTATION

submitted in partial satisfaction of the requirements
for the degree of

DOCTOR OF PHILOSOPHY

in Engineering

by

Sarah Mulan Wang

Dissertation Committee
Professor G. Scott Samuelsen, Chair
Professor Stephen J. Davis
Professor Jean-Daniel Saphores

2020

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DEDICATION

I dedicate this Dissertation to my family - 媽媽, 爸爸, Cathryn, Mark, Mozart, and Uni – I could not have done this without your love and support.

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NOMENCLATURE

AEC	alkaline electrolyzer
ATB	Annual Technology Baseline
BES	battery energy storage
BEV	battery electric vehicle
CAES	compressed air energy storage
COG	Cost of Generation
CRF	capital recovery factor
DOE	Department of Energy
E3	Energy and Environmental Economics
EF	electrical furnace
ERE	Excess Renewable Electricity
ES	energy storage
FCEV	fuel cell electric vehicle
FO&M	fixed operation & maintenance
GHG	greenhouse gases
HES	hydrogen energy storage
HiGRID	Holistic Grid Resource Integration and Development
I-BEV	immediate BEV charging
ICEV	internal combustion engine vehicle
LCFS	Low Carbon Fuel Standard
LCOE	levelized cost of energy
Li-Ion	lithium-ion
MCFC	molten carbonate fuel cell
Na-S	sodium sulfur
NGPPCC	natural gas combined cycle power plant
NGPPCT	natural gas combustion turbine power plant
NREL	national renewable energy laboratory
P2G	power-to-gas
P2G2P	power to gas to power
PAFC	phosphoric acid fuel cell
Pb Acid	advanced lead acid
PEMEC	proton exchange membrane electrolyzer
PEMFC	proton exchange membrane fuel cell
PHES	pumped hydro energy storage
PHEV	plug-in-hybrid electric vehicle
ppm	part per million
PV	solar photovoltaic
R-CH_4	renewable methane

R-H_2	renewable hydrogen
RPS	Renewable Portfolio Standard
S-BEV	smart BEV charging
SCE	Southern California Edison
SMR	steam methane reformation
SoCalGas	Southern California Gas
SOEC	solid oxide electrolyzer
SOFC	solid oxide fuel cell
TSC	total system cost
V2G	vehicle to grid
VMT	vehicle miles traveled
VO&M	variable operation & maintenance
YSZ	yttria stabilized zirconia
ZEV	zero emission vehicle
Zn Br	zinc bromide

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CURRICULUM VITAE

SARAH WANG

Education

University of California, Irvine **April 2015 – September 2020**
M.S. in Environmental Engineering Awarded Fall 2017
PhD in Environmental Engineering Expected September 2020
Principal Investigator: Professor Scott Samuelsen
Overall GPA: 3.98/4.0

University of California, Santa Barbara **September 2010 - June 2014**
B.S. in Chemical Engineering
Overall GPA: 3.51/4.0

Research Experience

UCI Advanced Power and Energy Program, Scott Samuelsen **April 2015 – September 2020**
Graduate Researcher, funded by the Advanced Power and Energy Program

- Implementing data acquisition system and technology transfer to the UCI Medical Center's newly installed Fuel Cell system
- Modeling the California electric grid under high renewable penetration to determine the usage of otherwise curtailed energy through energy storage, renewable gas production, or transportation fuel.

UCSB Materials Lab, Michael Chabinyc **March 2012 – June 2014**
Undergraduate Researcher, partially funded by CEEM

- Fabricated organic solar cells with fullerenes, polymers, and organic solvents
- Determine physical and optoelectronic characteristics of solar cells using UV/Vis spectroscopy, AFM, and solar simulation methods.

University of Oxford Materials Lab, Hazel Assender **July 2013 – September 2013**
Undergraduate Researcher, funded by CISEI fellowship

- Fabricated organic-inorganic hybrid solar cells with lead sulfide nanocrystals
- Conducted degradation tests exposing devices to various environments

Work Experience

Imerys Filtration & Additives North America **July 2014 – December 2014**

Air Flow Efficiency Engineer Intern

- Analyze air flow of a diatomaceous earth process plant
- MSHA and man lift trained
- Internship also included a $5,000 scholarship for the 2013-2014 school year

Schneider Electric **Jan 2020 – March 2020**

Energy Engineer Intern

- Conduct on-site energy audits
- Analyze energy use and suggest potential energy savings for clients
- Analyze potential solar generation and battery energy storage

Publications

Sarah Wang, Brian Tarroja, Lori Smith Schell, Brendan Shaffer, Scott Samuelsen, "Prioritizing among the end uses of excess renewable energy for cost-effective greenhouse gas emission reductions," Applied Energy, Volume 235, February 2019, 284-298

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ABSTRACT OF DISSERTATION

Use of Excess Renewable Electricity Generation to meet Future California Stated System Goals

By
Sarah Wang
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University of California, Irvine, 2020
Professor G. Scott Samuelsen, Chair

The integration of renewable resources, such as wind and solar, is essential to establishing low or zero-carbon systems for climate mitigation. To set this in motion, technologies are necessary to capture the variable, intermittent excess renewable electricity (ERE) generation that exceeds the electric demand. Technologies which can utilize ERE include (1) electric vehicles for zero-emission transportation; (2) energy storage technologies to store renewable generation for later use; and (3) electrolyzers to produce hydrogen for later use in stationary fuel cells and fuel cell electric vehicles. Due to the variety in costs and operational constraints of the technologies and integration to serve different end-uses, an evaluation of low-cost technology is required portfolios to meet stated system goals, such as the renewable penetration into the electric grid.

Through linear optimization programming, a methodology was developed to determine the least-cost technology portfolio to achieve the stated system goals. The stated system goals and demands, considered in this study, were based on California as a representative case with the goals for the electric grid of 60% renewable portfolio standard (RPS) by 2030 and zero-carbon by 2045. Demand projections were based on the Energy and Environmental Economics PATHWAYS model commissioned by California state agencies.

The results show that the optimized technology portfolios vary depending on the availability of renewable generation. To meet the 2045 goal, for example, the technology portfolio is reliant on (1) higher efficient technologies when less ERE is available and the cost is lower and (2) lower efficient technologies when a higher ERE is available. The lowest total system cost occurs when ample ERE is available, thereby allowing the use of less expensive, lower efficient technologies and the ability to curtail portions of the ERE without having to deploy large capacity electricity capturing technologies to intake peak solar, resulting in 48% curtailment as a percent of the electric demand. This trend is also seen for the 2030 60% goal. However, for the 2045 zero-carbon electric grid, long duration storage is necessary to ensure the seasonally variable renewable generation is properly managed.

1 INTRODUCTION

1.1 Motivation

Humans have left a mark on Earth through the development of infrastructure, increase in population, and increase use of energy as human advancement [1], [2]. The Earth can usually be considered a vast system where the energy balance in and out over the periods of human lives is negligible. This is primarily true for the billions of years where the species depended on solar energy, growing plants through photosynthesis and providing food and energy to all living things. However, with the development using fossil fuel energy, such as petroleum and natural gas, and the introduction of technologies, such as the internal combustion engine, the rate of energy use has increased exponentially [3]. This unsustainable progression of growth is negatively effecting environmental health, as the concentration of carbon dioxide has significantly increased in the past decades as composed to the past hundreds of thousands of years, as seen in inspired by data from the National Aeronautics and Space Administration [4], [5]. This trend is very unlikely to be due to natural climate variability alone and most likely to be due to anthropogenic sources, human activities [6].

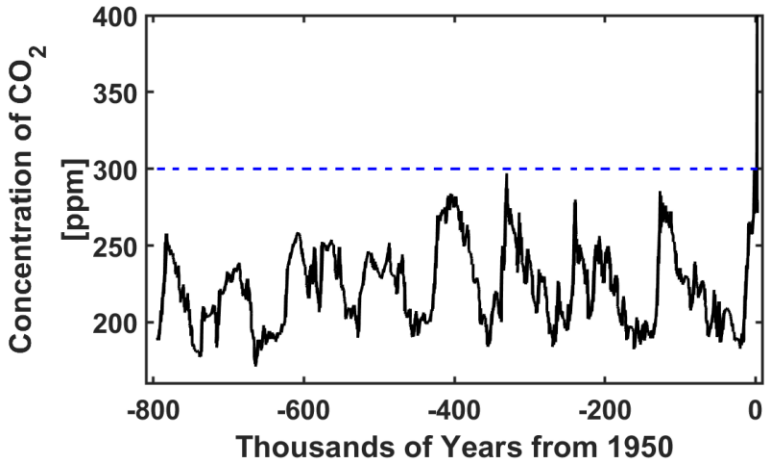

Figure 1: The carbon dioxide concentrations in the atmosphere since 1950. For the past hundreds of thousands of years, the concentration of carbon dioxide in the atmosphere does not exceed 300 part per million (ppm). However, in just the past 50 years or so the concentration has increased exponentially above the 300 ppm concentration, representing the anthropogenic carbon dioxide emissions [5].

There is evidence of more frequent and more intense extreme weather events that have increased significantly over the last decades which differ from trends and are attributed to anthropogenic origin [7]. A potential outcome from climate change is an increase in global temperature. A study by Schleussner, Lissner, and et. al. found that there could be significant impacts of catastrophic climate change with global temperature increase of 1.5^{o}C and 2^{o}C [8]. This study found the range of changes to the climate, based on the global temperature increase, which mostly agreed with many previous papers coming to the same conclusions: The annual maximum value of daily maximum temperature increases [9]. The consecutive days of high temperature and low precipitation increases [10]. Fresh water availability becomes unreliable due to changes in the hydrological cycle and intrusion of salt water due to sea levels rising of extreme coastal flooding [11]. Agricultural crops yields will differ with climate change with

reductions in tropical regions and increases in high-latitude regions [12]. The coral reefs are particularly susceptible to the increased CO_2 concentrations and ocean acidification, suffering long-term degradation eventually leading to a change of the ecosystem [13].

Anthropogenic GHG concentration in the atmosphere will persist for years after ceasing all emissions [14]. A solution to impede the effects of climate change is to transition the energy system from carbon-based fuels which emit greenhouse gases (GHGs) to alternative sources such as renewable solar and wind. The need to offset GHG emissions is apparent and countries throughout the world are beginning to act. Global effort can be seen in the Paris Agreement, ratified by 184 parties, which unites most of the world to plan and regulate greenhouse gas emissions to mitigate climate change [15], [16]. California has enacted goals of achieving 100% zero-carbon electricity by 2045 [17]. However, renewable resources are unreliable due to intermittency and variability causing times of curtailment, when the generation exceeds the demand [18].

This dissertation addresses the use of excess renewable electricity (ERE) to provide zero-carbon energy to the electricity, transportation, and natural gas sector for the state of California. The analysis utilizes linear optimization to determine which technologies would best benefit the different sectors based on costs and GHG emission reduction. Previous analysis of the energy system examines the use of different technologies within a sector, compares the costs and GHG emission reductions for different technologies, and examines the sizing and operation of different technologies to meet a demand. This dissertation aims to optimize and determine the necessary technology portfolio to achieve California goals by 2045.

1.2 Research Goal

The goal of this dissertation is to develop an optimization model and method to determine the role and projection of zero-carbon technologies which utilize excess renewable electricity to 2045. This work examines the effects of technology parameters and costs to identify the main factors which are important to develop a cost effective zero-carbon energy system. The results of this work will inform the selection of end-use technology types in reducing GHG emissions and meeting California's 100% zero-carbon target.

The novelty of this dissertation is the optimization which is based on the use of ERE as opposed to the demand such as electricity or hydrogen loads as well as the potential to project technology installation to 2045 based on goals set by California legislation. The optimization model utilizes YALMIP to initialize the constraints and objective function, and CPLEX, which is a simplex method linear optimization [19], [20]. The optimization input and ultimate cost results rely on the Holistic Grid Resource Integration and Development (HiGRID) tool which simulates the California electric grid depending on the installed capacity of renewable electricity generation, developed in the Advanced Power and Energy Program [21].

1.3 Objectives

To meet this dissertation goal, the following objectives will be completed:

TASK 1: COLLECT END-USE DEMAND FOR TRANSPORTATION FUELING/CHARGING AND NATURAL GAS USAGE. COLLECT AND UPDATE TECHNOLOGY PARAMETERS AND COSTS. UPDATE THE CALIFORNIA GRID SIMULATION MODEL FOR ALLOWING NEW TECHNOLOGY ANALYSIS.

TASK 2: CONDUCT INDIVIDUAL PATHWAY ANALYSIS TO UNDERSTAND THE POTENTIALS OF EACH ENERGY SECTOR (TRANSPORTATION, ELECTRICITY, NATURAL GAS) TO REDUCE GHG EMISSIONS THROUGH THE UTILIZATION OF EXCESS RENEWABEL ELECTRICITY.

TASK 3: DEVELOP AN OPTIMIZATION MODEL WHICH UTILIZES EXCESS RENEWABLE ELECTRICITY FOR: ELECTRICITY STORAGE, ZEV TRANSPORTATION CHARGING/FUEL PRODUCTION, AND RENEWABLE NATURAL GAS.

TASK 4: ANALYZE VARIOUS OPTIMIZED TECHNOLOGY PORTFOLIOS FOR THE REPRESENTATIVE YEARS OF 2030, FOR A 60% RENEWABLE ELECTRIC GRID, AND 2045, FOR A ZERO CARBON ELECTRIC GRID.

TASK 5: EVALUATE THE IMPACTS OF VARIABLES ON THE OPTIMIZATION RESULTS SUCH AS TECHNOLOGY COST AND EFFICIENCY. DETERMINE THE VALIDITY OF OPTIMIZATION ASSUMPTIONS.

TASK 6: PROJECT TECHNOLOGY PARAMETERS AND COSTS OF THE CONSIDERED TECHNOLOGIES FROM 2030 TO 2045 TO DETERMINE THE OPTIMIZED INSTALLATION OF TECHNOLOGIES TO MEET CALIFORNIA'S GHG EMISSION GOALS.

2 BACKGROUND

2.1 California's goals

California is committed to achieving 100% zero carbon electricity sales by the year 2045 [22] and has been a leader in enacting measures to reduce GHG emissions [23], [24] by increasing renewable resources to reach higher renewable portfolio standard (RPS) [25]. However, as installed renewable generation capacity under RPS policies increase, the intermittency of renewable generation may become unmanageable as other power plants have to accommodate the variability of renewable energy, which may increase ramping rates and GHG emissions [26]. Increasing grid flexibility and integrating energy storage resources are necessary to incorporate and make use of the increasing renewable resources [27]. There is a push to reduce GHG emissions to 80% 1990 levels by 2050, as seen in Figure 2 with data taken from the California Air Resources Board [28].

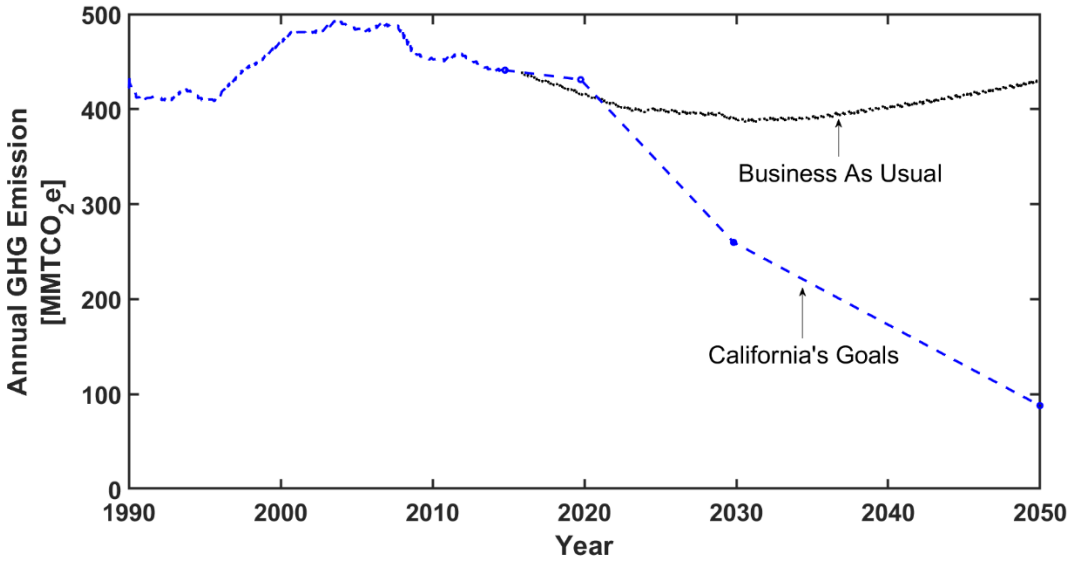

Figure 2: California's scoping plan to reduce GHG emissions, data taken from a report in the California's 2017 Climate Change Scoping Plan [28].

California is also committed to reducing GHG emissions in the transportation sector through Executive Order B-48-18 [29] which aims for 2.5 million zero-emission vehicles (ZEVs) by 2025. However, this shifts the fuel dependence from gasoline to other sources, such as the electric grid for battery electric vehicles. The electricity source is important to determine the GHG emission reduction [30]. If the electricity source is primarily coal the efficiency of the BEV must be high enough to offset the GHG emissions from the electricity generation. A study by the Union of Concerned Scientists determined the miles per gallon a gasoline vehicle would have to have in order to be equivalent to an electric vehicle charging from the electric grid of that state [31]. There is much work in legislation established by California to battle climate change. Table 1 lists out some policies that are focused on climate in California [32].

Table 1: California Climate Policies

Bill	Summary
Assembly Bill 32 [33], [34]	Reduce GHG emissions to 1990 levels by 2020 and 40% below 1990 levels by 2030
Senate Bill 350 [35], [36] **Senate Bill 100 [17] (an update)**	60% of all electricity from renewable resources by 2030 and 100% from carbon-free sources by 2045
Senate Bill 1 [37], [38]	Increase gasoline tax by $0.12 per gallon for improvements in transportation efficiency and emission reductions funding
Senate Bill 375 [39], [40]	Coordinating transportation and land use planning to reduce GHG emissions for more sustainable, healthier, and more livable communities

2.2 California's current state

2.2.1 GHG Emissions

California has been a leader in reducing greenhouse gas emissions while maintaining economic growth. This is due to the investment in clean energy. In 2017 investors poured $2.5 billion into U.S. clean energy technology with more than half going to California companies, which results in more good jobs and more innovation [41]. This success is primarily attributed to the push for the installation of renewable energy technologies. The California GHG Emissions inventory for 2000 to 2017 saw that total electricity generation from zero-GHG sources (solar, hydro, wind, and nuclear) exceeded generation from GHG emitting sources [42]. However, despite these advances in reducing GHG emissions, there are still a significant amount of emissions with 424.1 $MMTCO_2e$ emitted in 2017, as seen by the 2017 values in Table 2 [43]. To

achieve a net zero-carbon system, California needs to reduce a significant amount of GHG emissions.

Table 2: 2017 values for California [43].

Metric	Associated 2017 Value
GDP	2.6 trillion (2012 $)
Population	39.6 million
GHG Emissions	424.1 $MMTCO_2e$
GHG Emissions per Capita	10.7 metric tons CO_2e per person
GHG Emissions per GDP	164 metric tons CO_2e per million dollars

The primary sector attributing to GHG emissions is the transportation sector, which accounts for 41% of total statewide emissions, as seen in Figure 3. The electricity sector has been able to reduce the GHG emissions over time by the installation of renewable energy technologies, such as solar and wind.

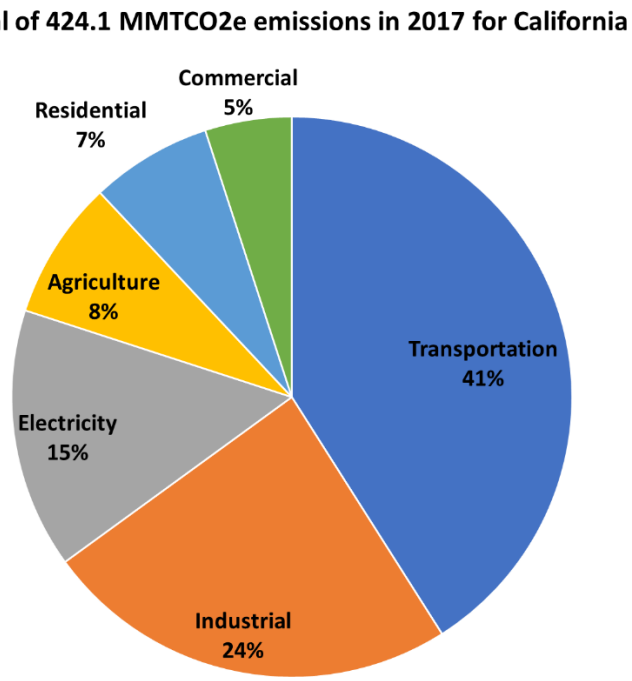

Figure 3: The total GHG emissions divided into different sectors in California, data taken from the California Air Resource Board [43].

California has also enacted economic incentives for GHG emission reductions through the Cap and Trade program [44]. The total GHG allowance decreases over the years to reduce GHG emissions while the market determines the market price [45]. Cap and Trade is not a tax and is an approach that utilizes the market to determine cost-effective emission reductions. The Low Carbon Fuel Standard (LCFS) has helped decrease the carbon intensity of California's transportation [46]. The LCFS helps give credits to non-conventional transportation fuels, such as hydrogen and electricity, and conventional transportation fuels have a credit deficit [47], [48]. These credits have a market dependent price for trading, like Cap and Trade. Hydrogen for transportation in California is also between 37% to 44% renewable to further reduce GHG emissions from the transportation sector [49].

2.2.2 Electric grid

The California electric grid relies on a variety of generation sources, as detailed in Figure 4 with data taken from the California Energy Commission for 2018 [50]. The total electric generation amounted to 285,488 GWh for 2018.

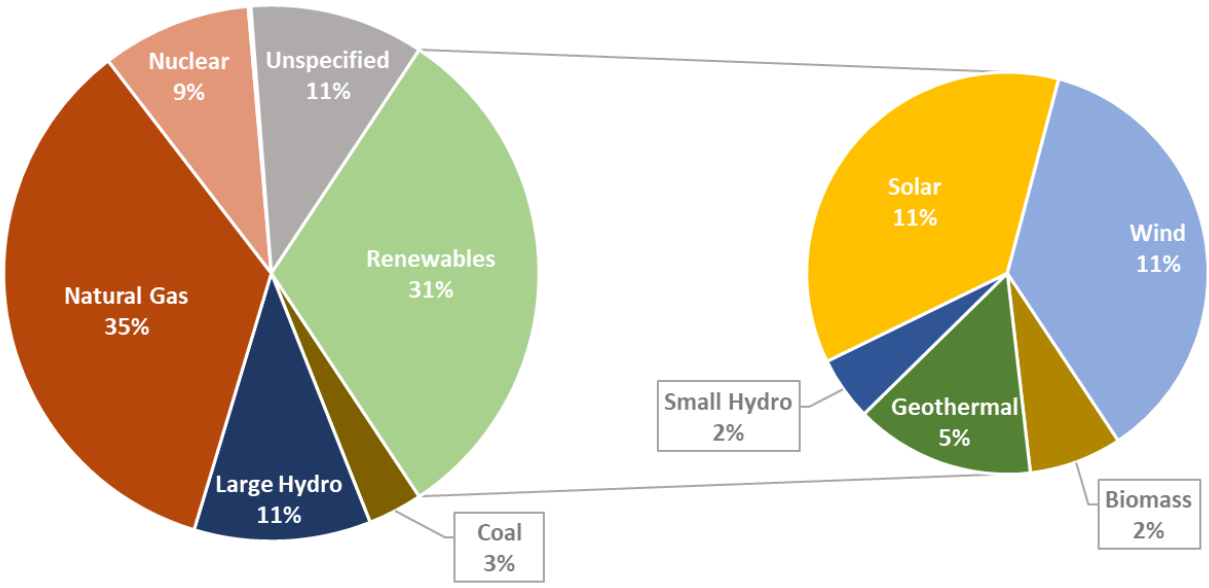

Figure 4: The total distribution of electric generation for California in 2018. The renewable portion of the electric grid is broken up as seen in the right chart, data taken from the California Energy Commission for 2018 [50].

The largest single resource provider of electricity generation is natural gas; however, natural gas has seen a decrease in electricity generation over the years. In 2012 natural gas provided 130,995 GWh of electricity generation, larger than compared to in 2018 which was 99,644 GWh [51]. However, even as natural gas decreases in electricity generation the need for its dispatchable abilities is still present, as seen in Figure 5 by the change in power capacity [52]. The rate of change in power capacity decrease for natural gas is slower than the rate of change in power capacity increase for renewables.

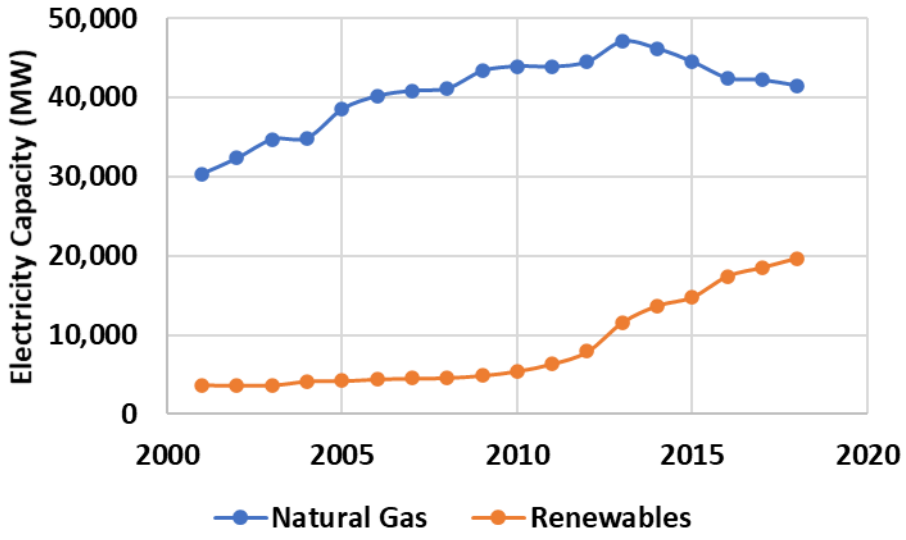

Figure 5: The electric power capacity of natural gas and renewables from 2000 to 2018, data from [52].

Renewable electricity generation amounts to 31% of total generation or 89,502 GWh. The primary sources for renewable electricity are solar and wind, both approximately 11% of the total electric generation or 32,533 GWh and 32,711 GWh, respectively. To reach California's goals, more renewable installations are required. The increase in solar installation is possible as the price for installation has decreased [53]. However, the increased installation of renewable generation will not directly equate to increased renewable integration. At the current 34% renewable portfolio standard, there are times of curtailment where renewable electricity cannot be utilize due to mismatch between generation and demand [54]. This problem is due to the overgeneration of solar, which is currently experienced in the electric system CAISO [55]. Figure 6 showcases a representation of the hourly net load, the electric demand minus renewables, with overgeneration from solar. The positive portion of the net load is the necessary dispatchable generation to balance the load; the negative portion of the net load is the over generation of

solar. Solar generation cannot meet the demand at night, as it requires the sun to generate electricity, resulting in peaks in the net load at hour 18, or 6pm, which is when the sun sets. However, when there is solar generation, between hours 7 to 18 or 7am to 6pm, there is more generation than the electric demand, resulting in a negative net load. As the negative net load is the amount of electricity that cannot be directly utilize it would therefore be wasted otherwise without technologies to capture the excess generation. The valley also causes issues with requiring an extreme ramp from dispatchable resources to meet the afternoon demand.

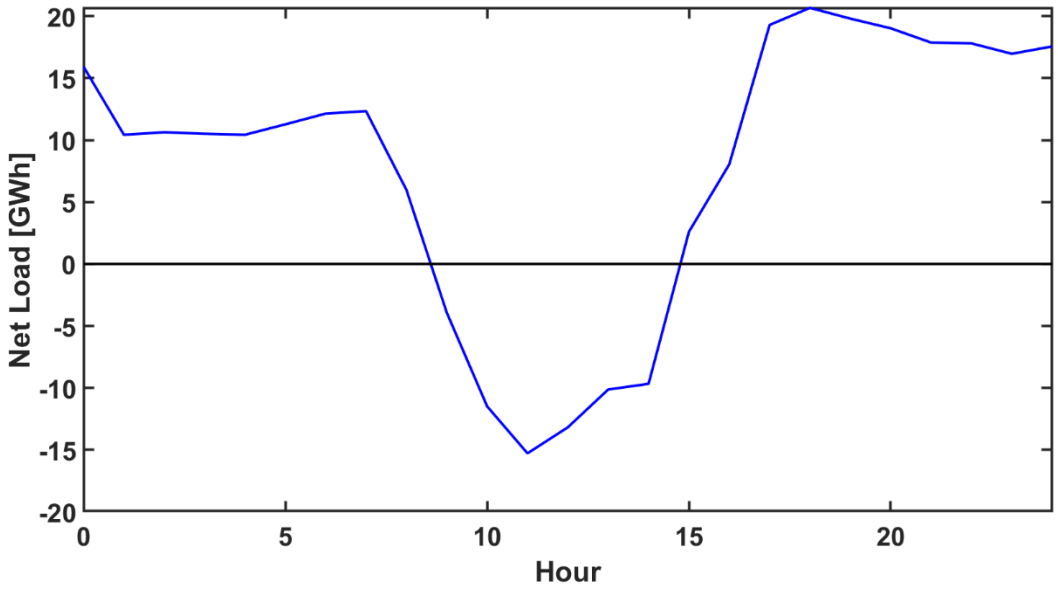

Figure 6: A representation of the net load for a day with excess solar generation, resulting to a negative net load during hours 8 to 15.

2.2.3 Zero-Emission Vehicles

There are over 29 million registered on-road vehicles in California which contribute to the transportation sector GHG emissions [56]. Only a small portion of the vehicles are ZEVs,

approximately half a million or less than 2% of total vehicles, which is far from the goal of 5 million ZEVs by 2030 [57], [58]. However, the market share of hybrid and battery electric vehicles (BEV) are on the rise and on pace to exceed 100,000 units in 2019 [59]. With fuel cell electric vehicles (FCEVs) coming into the market later than BEVs, there are currently 8,285 FCEVs sold or leased in the US, with a main percentage in California [60].

To help promote further adoption of ZEVs, there are rebates and incentives available, such as the LCFS described under GHG Emissions. Currently, there are 100 total approved hydrogen dispensing stations in California and 454 direct current fast charging that are legible for LCFS [61]. There is also the California Clean Vehicle Rebate Project which provides rebates for eligible vehicles and depend on funding availability [62]. There is also incentives from utilities, such as Southern California Edison (SCE) which offers rebates for the purchase of an BEV [63]. SCE also manages charging time by providing BEV specific rates [64]. The goal is to avoid charging during the 4pm to 9pm peak load by offering cheaper electricity during off-peak hours.

2.3 Technologies

Renewables generation has high potentials to reduce GHG emissions. A study by Macdonald, Clack, and Alexander found that reducing GHG emissions by 80% relative to 1990 levels is possible without increasing levelized cost of electricity [65]. However, renewable sources (i.e. solar and wind) requires control strategies to manage the variability and intermittency of generation such as energy storage [18], [27], [66], [67], [68]. Many technologies are necessary to manage the future electric grid to accomplish high to 100% renewable integration. This study

considers a variety of technologies which can utilize renewable generation to offset conventional fossil fuel combustion.

2.3.1 Electricity Generation

There are many types of electricity generation, this study will focus on the ones described below.

Solar Photovoltaic

Solar photovoltaic (PV) converts photons from light to electricity through the photovoltaic effect [69], [70]. A PV solar cell is comprised of semiconductors that allow photons to excite electrons to produce electricity [71]. Typically, a solar panel, or module, consists of many PV cells to boost the power output. Models can be connected to form arrays; this allows PV systems to be built to almost any size and for a wide range of use to small systems on building roofs to large utility systems.

Solar is a main contributor to the production of renewable electricity in California, due to the high potential for solar PV electricity generation [72], [73]. However, the availability of solar is limited dependent on weather, such as cloud coverage, time of day, as the sun rises and sets, and location [74].

On-shore Wind

Wind energy is a rather simple technology. A wind turbine is composed of blades similar to an airplane wing [75], [76]. The blades are shaped such that the air travels a longer distance on one side than the other. The longer distance side creates a lower pressure air pocket that lifts

the blade towards that direction, therefore turning the turbine. The rotation of the turbine produces electricity through the conversion of mechanical to electrical energy [77]. There are wire coils which surround an electromagnetic shaft that when rotated produces a current of electricity.

Wind is the second main contributor to the production of renewable electricity in California [72]. Wind is more limited than solar due to the limited availability of high wind areas in California [78].

Hydropower

Hydropower produces electricity through the use of flowing water to spin turbines [79], [80]. Typically, a dam or similar structure is installed to convert the motion of water to electricity. The installation of a hydropower plant is relatively low cost which influences its large contribution to electricity generation across the United States, about 7% of total electricity generation and 52% of renewable electricity generation [81].

Hydropower is limited to the location of large bodies of flowing water and has some environmental issues [82]. Hydropower does not directly emit air pollutants but can affect the environment. Dams can obstruct fish migration and can change the natural water (such as temperature, chemistry, or river flow). These changes can also negatively affect the local wildlife and plants.

Geothermal

Geothermal energy generates electricity through the use of heat from the earth [83], [84], [85]. There are a variety of geothermal resources, but all rely on underground heat that is used

to spin turbines to produce electricity. The availability of geothermal is limited, depending on location, but California contains the largest amount of geothermal electric generation in the United States due to its location over the Pacific's "ring of fire" which is due to tectonic plate conjunctions [86].

Natural Gas Power Plants

Natural gas power plants is the main source for electricity in California and has largely replaced coal electricity generation throughout the United States [87]. The two main natural gas power plant technologies considered in this study are a natural gas combustion turbine (NGPPCT) and a natural gas combined cycle (NGPPCC) power plant system.

A NGPPCT system produces electricity through the compression and combustion of natural gas which runs through a turbine [88]. The hot gas expands through the turbine and rotates the turbine blades. Similar to a wind turbine, the rotation of the blades produces electricity. A NGPPCC system produces electricity similarly to a NGPPCT, but with an added steam turbine that captures the heat exhaust to drive another generator to produce electricity. Since the NGPPCC can utilize the waste heat while the NGPPCT does not, it is more efficient. Typically NGPPCC are used for load following operation, more continuous operation to ensure balancing of the load, while NGPPCT are used as peaker power plants, operating for short periods of time when there is a sudden need for electricity generation that cannot be met with other technologies.

2.3.2 Energy Storage

Due to the intermittency and variability of renewable power, energy storage has been identified as a solution to match the renewable generation and demand [89], [90]. There are many types of energy storage that differ on a wide variety of characteristics, such as technology type, storage capacity, efficiency, and storage type [91], [92]. The basic principle of each energy storage type is the ability to charge and discharge electricity or energy. First battery energy storage systems (Lithium-Ion and Zinc Bromide) will be discussed, followed by pumped hydro, compressed air, and power-to-gas energy storage.

Lithium-Ion Battery Energy Storage

Lithium-Ion (Li-Ion) batteries are rechargeable batteries which store electricity through the charging and discharging of lithium ions between the positive cathode electrode and the negative anode electrode [93]. The battery material is typically a lithium-metal oxide, combinations containing cobalt, nickel, and manganese have proven to combine the best properties amongst the metals while minimizing drawbacks [94].

Li-Ion batteries are a main dominant energy storage system for portable electronics, with projections of continuous growth in usage [95]. They are found in many consumer products such as cell phones, wireless devices, and many more everyday items. Although Li-Ion batteries are a main choice for smaller devices, larger devices have challenges due to the high cost due to special packaging and internal overcharge protection circuits [96].

Zinc-Bromide Battery Energy Storage

Zinc-Bromide (ZnBr) batteries are hybrid redox flow batteries [97], [98]. In each cell, two electrolytes are used in two compartments separated by a porous membrane. During charge, the metallic zinc is reduced to a thick film on the anode side while the bromide ions are oxidized to bromine. During discharge, the zinc is oxidized to ion and dissolved into the solution while the bromine is reduced to bromide ions. The energy storage solution can be decoupled from the battery, therefore decoupling the power and energy for application flexibility.

Pumped Hydropower Storage

Pumped hydropower storage (PHES) uses water and gravity to store energy [99]. Typically, there are two reservoirs lower, at the bottom of a hill, and upper, at the top of a hill [100]. To charge, electricity is used to spin turbines to pump water from the lower reservoir to the upper reservoir. To discharge, the water is flowed from the upper reservoir to the lower reservoir and the flow of water spins the turbines to generate electricity. PHES is more mature, used as early as the 1890s, and have relatively low capital cost per unit of energy with many in operation worldwide [101]. The lifetime of PHES ranges between 40-60 years [96]. In California there are limitations to the capacity of hydropower, currently the limitations are 15 hours at maximum discharge and 3967 MW [102], [103].

Compressed Air Energy Storage

Compressed air energy storage (CAES) is a mature, reliable energy storage technology [104], [105]. The technology has been around for a long time, as early as the 1970s for use for load following and peaking power plants [106]. A CAES system can use excess renewable

electricity to compress and store air. The air can be stored in large underground caverns or aboveground pipes or vessels with bulk energy capacity like PHES. The air is later released, heated, and expanded for use in a turbine-generator to produce electricity during times of high electric demand [107].

Hydrogen Energy Storage (Power-to-Gas)

Another form of storage is to take excess electricity to produce hydrogen, known as power-to-gas (P2G). Hydrogen has been referred as a "Freedom Fuel" due to its ability to serve as a dispatchable resource while remaining free from relying on other countries for supply [108]. Hydrogen is the most abundant element in the universe but is typically not naturally found in gaseous form, primarily found in water [109]. Hydrogen can be produced from electrolysis using renewable electricity. The hydrogen can be used in a fuel cell to produce electricity or be injected directly into the natural gas pipeline to offset combustion of non-renewable natural gas, an overview of P2G can be seen in Figure 7. The following sections will review the technologies used to accomplish P2G: electrolyzer, fuel cell, and methanator.

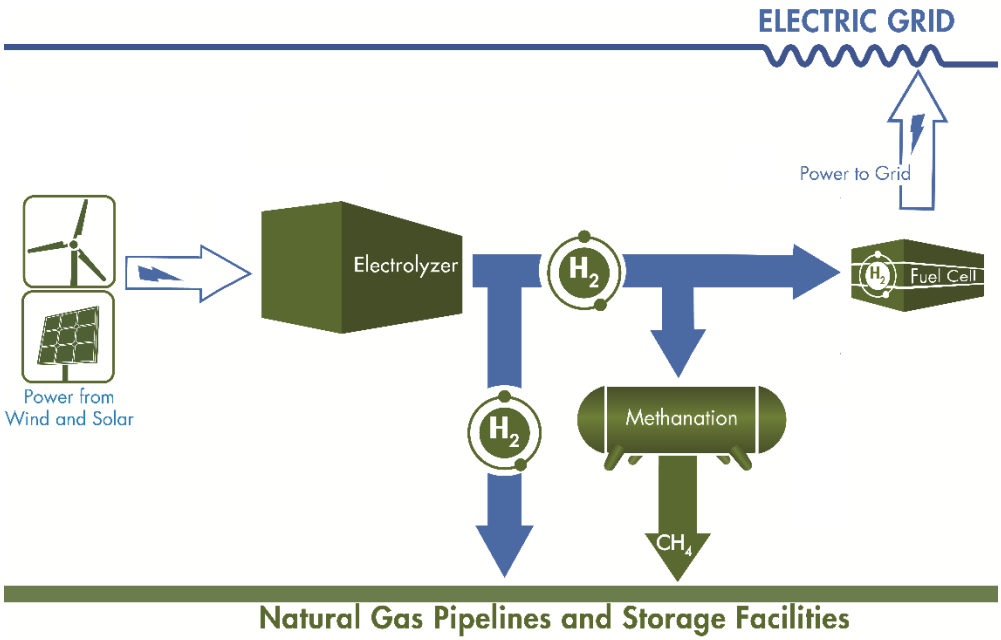

Figure 7: An overview of Power-to-Gas.

Electrolyzers – Hydrogen Production from Electricity

Electrolysis decomposes water to hydrogen and oxygen with electricity as the driver of the non-spontaneous reaction [110]. This process is simple in theory and can be demonstrated with pencils and a battery [111]. The main electrolyzer technologies, in order of most mature to least mature technology, are alkaline (AEC), proton exchange membrane (PEMEC), and solid oxide (SOEC) electrolytic cells with different efficiencies, as seen in Table 3 [112], [113]. The main differences between these technologies are the materials used for the electrolyte and described as followed [114], [115], [116]. The design of the technologies are similar and is that of an electrolytic cell with either a membrane or electrolyte coupled with an anode and cathode attached to an electricity source, seen in Figure 8.

Table 3: Efficiency of electrolyzer technologies [113].

	A EC	S OEC	P EMEC
Efficiency (kWh/kg H2)	4 6-56	3 5-36	5 0-55

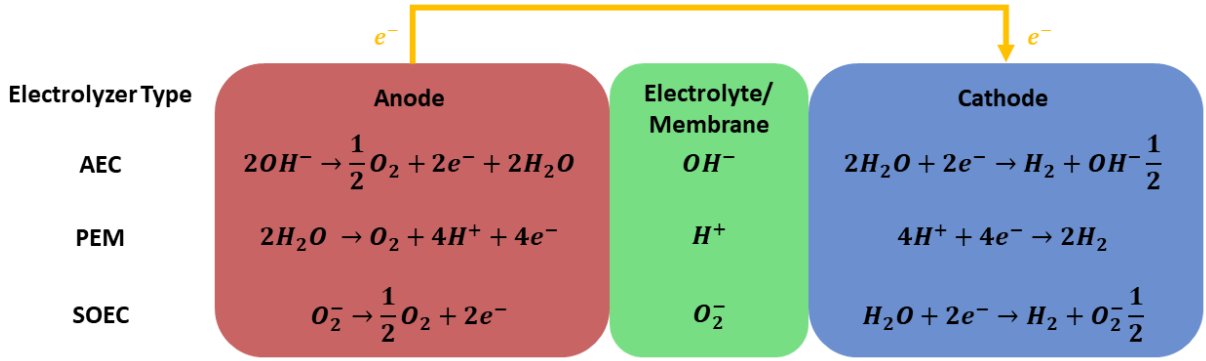

Figure 8: Chemical reactions at the anode, cathode, and the ion which travels between the two in AEC, PEM, and SOEC.

The AEC is the main electrolysis technology for hydrogen production in industry as it the most mature. The biggest advantages for an AEC system is the robust lifetime and lower cost due to cheaper electrode materials [117]. The electrolyte is an aqueous solution of potassium or sodium hydroxide to support the transfer or hydroxyl ions from the cathode to the anode. The cathode, with an electric current, reduces liquid water into hydrogen and hydroxyl ions. The hydroxyl ions migrate to the anode where the ions are oxidized into water and oxygen gas. To ensure the separation of the hydrogen and the oxygen gas, a diaphragm is typically used. The diaphragm is a microporous material to allow the transport of water and hydroxyl ions while maintaining a separation of the hydrogen and oxygen gases.

Electrolysis through a PEMEC has high production rate, high power density at low operating temperatures (80°C), can be compact, and results in high-purity hydrogen [118]. The

low temperatures are required to ensure membrane hydrogen for proton transfer. The configuration of a PEMEC consists of a cathode and an anode separated by a polymer membrane which allows only passage of protons. The anode layer decomposes water to oxygen gas and hydrogen proton ion. The hydrogen ion passes through a polymer membrane (Nafion) from the anode to the cathode to form hydrogen on the cathode layer [119].

High-temperature water electrolysis is the newest technology to emerge and has been growing interest in the scientific community due to the higher efficiency [120]. The high heat provided to the cell reduces the electric demand. Steam is fed to the cathode which is reduced into hydrogen gas and oxide ions. The oxide ions are attracted toward an anion conducting electrolyte and oxidized at the anode to produce gaseous oxygen. A common high-temperature water electrolysis technology is SOEC. SOECs are used due to the thermally stable materials and are modeled after solid oxide fuel cells (SOFCs), as fuel cells are the reverse reaction of electrolyzers.

Fuel Cells – Electricity Production from Hydrogen

Fuel cells are the reverse of electrolyzers. Instead of using electricity to produce hydrogen, fuel cells use hydrogen to produce electricity. The hydrogen that was produced from the electrolyzers can be stored for later use in a fuel cell to provide electricity during times of low net load. There are many different types of fuel cells, which vary depending on the materials like electrolyzers, with different efficiencies as seen in Table 4 [121], [122], [123]. Some fuel cell technologies are as follows: molten carbonate (MCFC), solid oxide (SOFC), proton exchange membrane (PEMFC), and phosphoric acid (PAFC) fuel cells. Fuel cells differ from electrolyzers as

the fuel can be more flexible and the ion is carried differently across the cathode and anode, as seen in Figure 9 [124], [125], [126].

Table 4: The different efficiencies for each fuel cell technology [121].

Fuel Cell Type	PEMFC	PAFC	MCFC	SOFC
Electrical efficiency	47.5%-55%	42.5%-45%	55%-60%	56%-72%

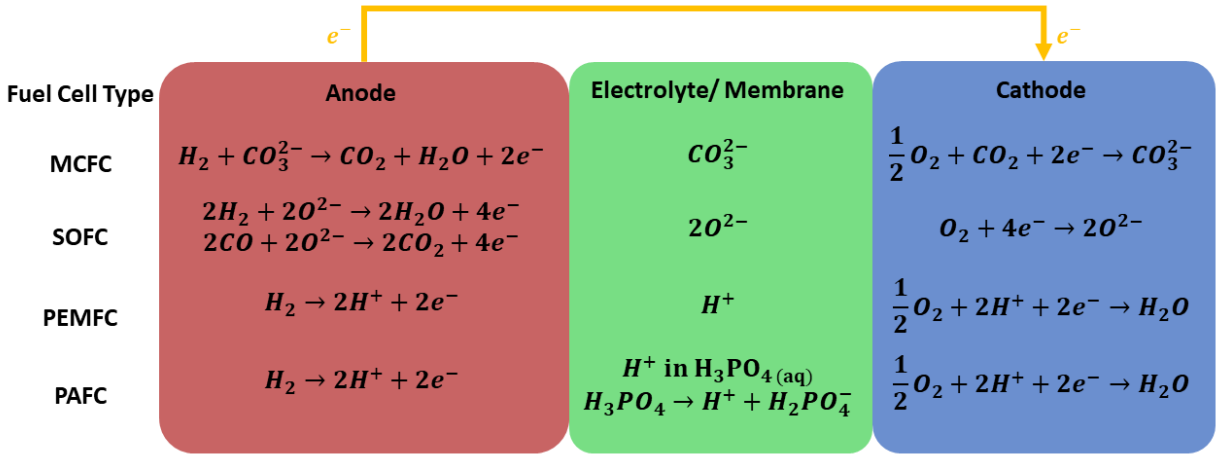

Figure 9: Chemical reactions at the anode, cathode, and the ion which travels between the two in MCFC, SOFC, PEMFC, and PAFC.

High temperature fuel cells, MCFCs and SOCFs have a long history, starting in the 1930s [127]. Research was first conducted with solid oxide materials in the 1930s with a switch in focus to molten carbonate in 1950s. MCFCs are high-temperature fuel cells with a molten carbonate salt mixture electrolyte [128]. The current state-of-the-art structures use nickel as both the metal for the anode and oxide for the cathode [129]. The cell is operated at temperatures around 650°C to and requires carbon dioxide for the reactions to occur, which allows for MCFC's fuel flexibility

to intake biogas, permitted treatment of the gas to remove poisons such as H_2S [130]. However, due to the high operation temperature in addition to the corrosive molten alkaline carbonate, degradation of the components is an issue.

SOFCs are like MCFCs in that they are high temperature and flexible in fuel use [131]. The high operating temperatures around 1000^oC allows natural gas to be reformed within the cell stack, eliminating the need for an external reformer and reduces the cost of the fuel cell system. Due to the high temperatures, the thermal expansion of the electrode materials must match. The main layout of SOFCs is two porous ceramic electrodes separated by an oxygen ion conducting electrolyte [132]. The material for the cathode is typically lanthanum manganite, a p-type perovskite oxide. The electrolyte conducts oxygen ions through a fluorite-structured oxide material, such as yttria stabilized zirconia (YSZ). The reduction reaction of the anode requires the use of nickel; however the thermal expansion of nickel is incompatible with YSZ and therefore the anode also requires a mixture of YSZ and nickel.

Unlike MCFCs and SOFCs, PEMFCs and PAFCs operate at lower temperatures. The PEMFC is like a PEMEC: two electrodes, made with platinum metal, separated by a Nafion electrolyte material [133]. Since the overall structure, reactions, and operation is similar but just reversed, PEMFCs can operate as a reversible fuel cell. Reversible fuel cells can operate as both a fuel cell and an electrolyzer [134]. This allows for the PEMFC to function to produce hydrogen during times when the net load is low and generate electricity from the previously produced hydrogen during times when the net load is high.

PAFCs operate at lower temperatures between 160^{o}C and 220^{o}C [135]. Similar to the PEMFC, the existence of platinum electrodes requires the lower operating temperatures and is also vulnerable to carbon monoxide and sulfur poisoning. The phosphoric acid electrolyte also presents potential corrosion issues. Some state-of-the-art PAFCs are eliminating the use of noble metals at the electrodes and transitioning the carbide matrix-based electrolyte membrane to polymer based.

Methanator – Injection of Hydrogen/Renewable Gas into Natural Gas Pipeline

Another option for the renewably produced hydrogen, is to inject it into the natural gas pipeline or produce renewable methane. This blending of hydrogen into the existing natural gas network is a means to integrate and store renewable energy while taking advantage of the current infrastructure. It would also provide renewable energy to gas end-use devices, such as household appliances. However, direct injection of hydrogen into the natural gas network can be achieved up to 5-15% by volume in order to maintain stability in end-use devices and without challenging the integrity of the natural gas pipeline [136], [137]. Hydrogen could also be synthesized to form methane or synthetic natural gas [138]. This would allow for higher penetration of renewable gas into the natural gas pipeline and does not limit hydrogen integration.

2.3.3 Vehicle Types

There are many alternatives to gasoline engine vehicles [139], [140]. BEVs and FCEVs have zero tail pipe emissions. Plug-in-hybrid electric vehicles (PHEVs) still have tail pipe emissions

but offer a great alternative to internal combustion engine vehicles (ICEVs) which is high in carbon emissions. The following sections will describe in more detail each vehicle type.

Internal Combustion Engine Vehicle

The most popular vehicle in operation is the ICEV, which accounts for around 90% of California sales in 2019 [59]. Gasoline and diesel fuel for ICEVs is derived from petroleum and most of the all oil produced goes to make transportation fuel [141]. To run an ICEV, fuel is combusted in an engine with a fixed cylinder and a moving piston [142], [143]. The combusted fuel expands the piston which rotates the crankshaft to provide motion to the vehicle's wheels. Over time, the efficiency of the ICEV has increased from 12 miles per gallon to around 25 miles per gallon as of 2018 which directly correlates to a decrease in CO_2 emissions [144]. However, to achieve a fully zero-carbon emission system the ICEVs will have to be replaced with ZEVs or renewable fuel which result in net zero-carbon emissions are needed.

Battery Electric Vehicles

BEVs outnumbered ICEVs in earlier years [145]. However, as the ICEV technology advanced with the introduction of lead-acid batteries to replace cranking ignition, the interest in BEVs dropped due to the limitations in driving range, costs, and performance [146], [147]. Now, GHG emission targets require decarbonization of the transportation sector which requires zero emission vehicles, such as BEVs. The carbon emissions of BEVs is dependent on the electric grid of which it charges from. Around 75% of people in the United States can charge a BEV off of the local electric grid to be equivalent to a 50 miles per gallon or higher efficient gasoline car in terms of GHG emissions [148].

The design of BEV powertrain consists of a battery, converters, motor, and control system, with continual improvements with different proposed configurations [149], [150], [151]. Li-Ion batteries are mainly used in application for high energy and power density uses, and is perfect for BEVs, although the recharge time is longer than ICEVs [152]. Although, plans for faster charging are in place as the U.S. Department of Energy (DOE) set goals for 20 miles per minute or more [153]. There are also multiple charging strategies and charging locations which can better match renewable generation [154], [155].

Plug-in Hybrid Electric Vehicle

To reduce fuel use, ICEVs can be outfitted with hybrid electric powertrains to make PHEVs [156]. PHEVs have both an internal combustion engine and an electric motor, essentially a combination of an ICEV and a BEV [157]. PHEVs typically are outfitted with larger battery packs than hybrid vehicles (which cannot plug-in to charge electricity) which allows them to use just electricity to travel for shorter distances, around 10 to 50 miles [158]. These vehicles are a good alternative to start reducing tail pipe emissions by allowing for pure electricity driving while maintaining the benefits of a gasoline vehicle that can utilize the reliable gasoline fueling infrastructure.

Fuel Cell Electric Vehicles

Although hydrogen is considered an extremely flammable fuel, it is no more dangerous than a conventional ICEV [159], [160], [161]. The choice fuel cell technology for FCEVs is a PEMFC [162], [163]. This is due to its low operating temperature and quick start-up potential. FCEVs are fueled with pure hydrogen, as PEMFCs can be contaminated by fuel impurities, air pollutants,

and ions from corrosion of fuel cell system components [164]. The hydrogen can be produced from electrolyzers or from fossil fuels, currently 33% of hydrogen must come from renewable sources [165], [166]. Due to requiring pure hydrogen for refueling, dedicated hydrogen fueling stations are required and currently lack a large infrastructure as compared to ICEVs [167].

Biofuel Vehicles

Although there is high potentials for the use of biofuels in vehicles to ensure a future low carbon emission, high renewable energy system, there are limitations on the availability of biofuels [168]. Since the main focus of this Dissertation is the interaction of renewable fuels with the electric grid, biofuels will not be considered.

2.4 Limitation and Variability of Renewable Resources

There is an abundant of renewable resources that have enough energy to power the entire world. For example, if the unpopulated area of the Sahara desert was covered with solar panels, it could provide energy to fuel the entire world [169]. However, renewable resources are limited on location, are variable, and are unreliable. It is not feasible to transmit the solar power to the populated areas of the world. Local resource generation is necessary. Some sites have access to more and different types of renewable generation than others. For example, Brazil has access to a lot of hydro and has potential to reduce GHG emissions to benefit health [170]. Europe has approximately 52.5 TW of untapped onshore wind power potential [171]. The different types of renewable generation also vary differently, with wind and solar requiring generation predictions as non-dispatchable resources [172].

The U.S. varies in terms of renewable generation availability per region. The states found in the south have high potential for wind power generation with Texas ranked number 1 of wind generation in the U.S. [173], [174]. The ideal place for wind turbines is where the average annual wind speed is at least 9 miles per hour, for small turbines, or 13 miles per hour, for utility-scale turbines. However, there are many regional geographic features which could result in reductions in power fluctuations [78]. In addition to location, the temporal operation of wind generation varies every hour and season. Fortunately, in California the seasonal variability of wind generation matches the seasonal demand, April through October [173]. This is not the case for Texas which curtails wind generation throughout the entire year [175]. The variability of wind is often difficult to predict and varies significantly throughout the seasons, potentially requiring long duration storage to best use the wind generation.

In comparison with wind, solar has a more consistent diurnal pattern as the sun consistently rises and sets every day. Although, there may be variability with the output of solar generation during the day depending on weather and cloud cover. There is also low energy density for solar, requiring a significant amount of land [176]. For the U.S., the states in the southwest region have large potential for solar generation [177]. California has a large installation of solar power and is seeing episodes of curtailment despite reaching renewable penetrations of only around 40%, even to the point of paying other states to take in the excess generation [178], [54]. This presents issues of reaching higher renewable penetrations as solar is only available during the day, despite the need for energy at night as well, with the electric demand peaking after the sun sets [55], [179].

Some base load non-carbon emitting resources are geothermal and hydro. Geothermal is limited in resources as its concentrated is in the mid-west, with a relatively small capacity available in California [180]. Hydro has high potential to meet the bulk of electric demand for many states and countries, however it is susceptible to drought [181]. Base load generation is easier to manage as it is dispatchable, consistent and fairly reliable (with exception of drought for hydro). Figure 10 shows a couple days representing the extreme curtailment in an electric grid achieving 75.7% renewable penetration for California. Despite having more than three times the amount of curtailment compared to the electrical generation delivered with wind, solar, hydro, and geothermal resources, the electric grid is still less than 100% renewable and requires the use of peaker (combustion turbine) and load-following (combined cycle) natural gas power plants. The generation of renewable technologies are non-dispatchable and do not naturally meet the electric demand. Solar and wind could be captured to increase reliability and to manage the daily or seasonal changes in generation, which will require the installation of energy storage technologies. However, to meet higher and higher renewable penetration levels an exponential amount of energy storage will be required [182].

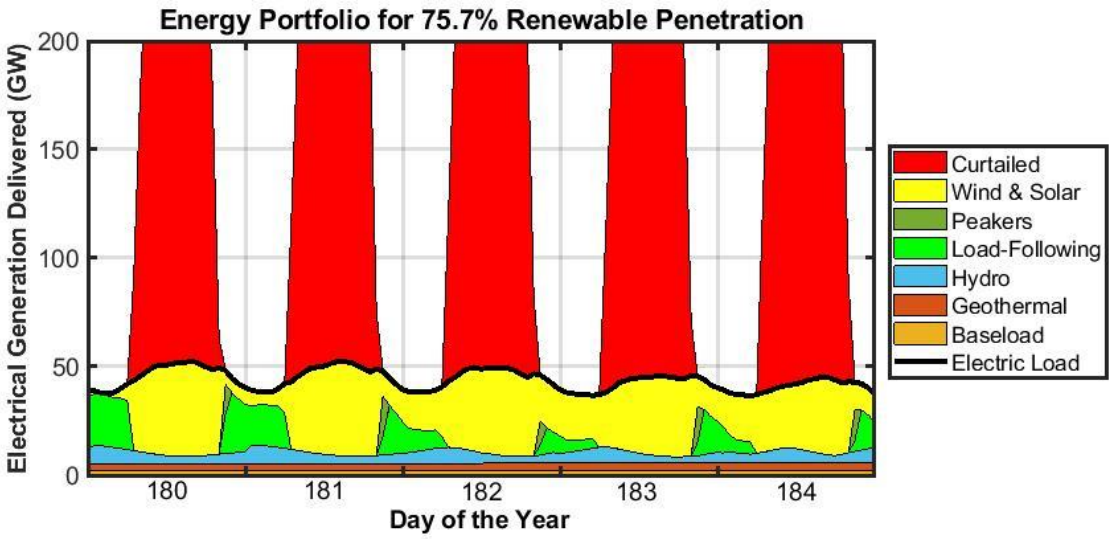

Figure 10: A representation of electrical generation delivered in comparison to the amount of excess generation that is curtailed.

2.4.1 Increase in the Electric Demand

The increase in electric demand, as seen in Figure 11, presents issues of requiring even larger integration of the variable and intermittent renewable generation [72]. The increase in electricity loads due to electrification is an effort to diminish the reliance on combustion of fossil fuels. Electrification has been hailed as the most significant engineering achievement of all time by the National Academy of Engineers as the transition of energy end uses, such as heating and transportation, to electricity in an effort to reduce CO_2 emissions [183], [184], [185]. Although this reduces the use of distributed fossil fuel use, it significantly increases the electric demand for the electric grid. For example, charging electric vehicles could significantly increase the electric demand [186]. And if coal is a large portion of the electricity resources, air quality could get worse in local urban areas [141]. The electric grid requires the integration of renewable

resources to eliminate CO_2 emissions, which have potential issues as described in the previous sections. Energy and Environmental Economics (E3) has projections of the electric demand increase as seen in Figure 11, which shows almost doubling the electric load from 2030 to 2050.

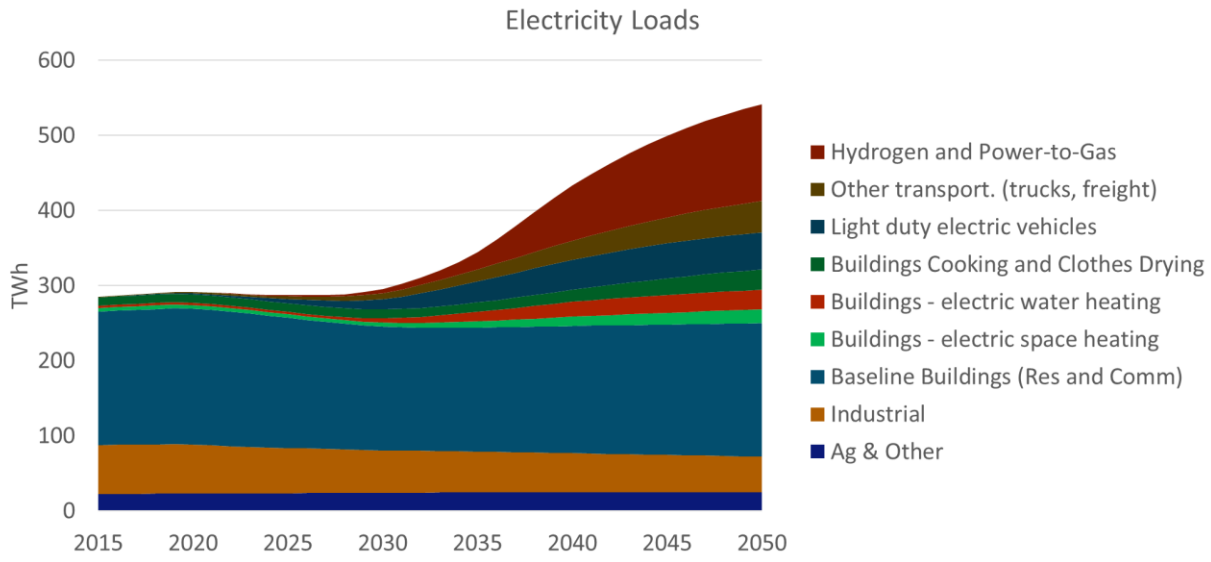

Figure 11: Projections of electricity loads based on E3's PATHWAYS, data from [72].

2.5 Optimization and Linear Programming

There are many different types of technologies which can utilize renewable technology. There is a wide range of potential options with varying advantages and disadvantages as well as used for different energy sectors. With such a complex variety of potentials and interaction between different energy sectors, it is necessary for an organized and objective approach. This is accomplished using optimization.

Mathematical optimization is the selection of the best feasible element, by finding the minimum or maximum of an objective, with regard to some constraints and conditions [187], [188]. A linear problem refers to a polynomial of degree one or less, in other words variables may

not be multiplied or divided by another variable only by a numerical value. A typical linear optimization problem is composed of variables, constraints, and an objective. The variables are represented with x and is a vector of the elements that the optimization is trying to select. The constraints are represented with A and b with both inequality ($Aineq$, $bineq$) and equality (Aeq, beq) constraints. The constraints A is a matrix that is sized as number of constraints by number of elements in the variable, the constraint for b is a vector that is sized by number of constraints. A generic linear optimization set of equations is defined as seen in Equation 1 to Equation 4.

Minimize:	$f * x$	Equation 1
Constraints:	$Aineq * x \leq bineq$	Equation 2
	$Aeq * x = beq$	Equation 3
	$lb \leq x \leq ub$	Equation 4

A simple optimization example can be seen below [189].

Variables	x_1,x_2,x_3,x_4	Equation 5
Minimize	$x_1 + 2x_2 + 3x_3 + x_4$	Equation 6
Constraints	$-x_1 + x_2 + x_3 + 10x_4 \leq 20$	Equation 7
	$x_1 - 3x_2 + x_3 \leq 30$	Equation 8
	$x_2 - 3.5x_4 = 0$	Equation 9
Bounds	$0 \leq x_1 \leq 40$	Equation 10
	$2 \leq x_4 \leq 3$	Equation 11

Equation 5 to Equation 11 are translated to vectors and matrixes presented in Equation 1 to Equation 4 as seen below. Although the example presented is fairly simple and can be

translated by hand, a toolbox for modeling and optimization such as YALMIP can more easily translate problems that are more difficult and time consuming to translate by hand [19].

Representation in Equation 1 to Equation 4	**Translation from Equation 5 to Equation 11**	
x	$\begin{bmatrix} x_1 \\ x_2 \\ x_3 \\ x_4 \end{bmatrix}$	Equation 12
f	$[1 \quad 2 \quad 3 \quad 1]$	Equation 13
$Aineq$	$\begin{bmatrix} -1 & 1 & 1 & 10 \\ 1 & -3 & 1 & 0 \end{bmatrix}$	Equation 14
$bineq$	$\begin{bmatrix} 20 \\ 30 \end{bmatrix}$	Equation 15
Aeq	$[0 \quad 1 \quad 0 \quad -3.5]$	Equation 16
beq	$[0]$	Equation 17
lb	$[0 \quad - \quad - \quad 2]$	Equation 18
ub	$[40 \quad - \quad - \quad 3]$	Equation 19

Once translated, the optimization can be performed through a solver. A linear optimization solver can adequately solve most problems, as long as the equations themselves are linear and the constraints are feasible. IBM ILOG CPLEX Optimization Studio (referred to as CPLEX) is an optimization software package which is a linear programming solver that uses the simplex method [190]. The simplex method uses slack variables and row reduction to find the

optimal solution, a simple example problem/solution can be found in APPENDIX A. CPLEX can also perform mixed integer programming, quadratic programming, and quadratically constrained programming problems. But this study will only use linear programming.

2.6 Comparison with Literature

Literature has previously explored the potential for compatible technologies to utilize renewable electricity. The E3 PATHWAYS model is a compilation of input from the California Air Resources Board, California Energy Commission, California Public Utilities Commission, and the California Independent System Operator and has been used to develop scenarios to reduce GHGs [72]. PATHWAYS considers the input of electricity, vehicle charging, hydrogen demand and simulates the electric grid without optimization. A study by Samsatli and Samsatli (2019) found an optimized heating system comprised of 20% hydrogen and 80% electricity coupled with renewable generation for Great Britain [191]. The study focused on the heating demand and does not consider the entire electricity system, utilizing new wind turbines as previously installed wind turbines are accounted as dedicated to electricity demand.

Previous studies have not optimized the utilization of excess renewable electricity for the electricity, transportation, and natural gas system and analyzed the effects of operational and economic parameters on the optimization. This study fills the gap by optimizing the utilization of otherwise curtailed renewable by comparing the cost of curtailment to the cost of technologies such as electrolyzes, energy storage technologies, fuel cells, methanations, electric vehicle chargers, and hydrogen fueling stations. The optimization aims to provide insight to the sectors and technologies which require the most development or achieve the most cost effective GHG

emission reductions as well as the necessary GHG emission reduction cost to allow for the proposed technologies to compete with curtailing renewable electricity.

2.6.1 Previous Literature on Greenhouse gas emission reductions

The potential to reduce GHG emissions from different technology options have been considered in previous studies. Different methods of reducing CO_2 emissions from the electric grid were compared in a study conducted by Forrest, Shaffer, *et al*. (2016) [192]. The study compared utilizing fuel cell, pumped hydro, compressed air, and flow battery technologies to offset peaker and load-follower power plants to reduce CO_2 emissions. This study found that fuel cells, fueled with natural gas, were able to reduce more CO_2 emissions and were more cost effective than the other considered technologies. Another study by Arciniegas and Hittinger (2018) found that operating energy storage to maximize revenue based on price of electricity resulted in an increase in CO_2 emissions and to maximize reductions in CO_2 emissions resulted in loss of revenue [193]. A study by McPherson, Johnson, and Strubegger (2018) found that large deployment of variable renewable energy is only possible if the high costs for hydrogen and storage technologies are reduced or offset by aggressive carbon constraint policies [194]. A study by Lipman, Ramos, and Kammen analyzed the potential of hydrogen and battery storage high levels of wind power in Southern California [195]. Studies have also found that implementing alternative vehicles and fuel platforms such as hydrogen FCEVs and BEVs were able to reduce GHG emissions [196], [197] & [198]. A study by Miotti, Hofer, and Bauer (2017) found that FCEVs and BEVs could result in lower GHG emissions if their fuel is from a renewable source [199]. However, FCEVs have more technological challenges as compared to BEVs, even when not

considering the need for hydrogen infrastructure. BEVs are more readily available than FCEVs but have limitations with recharge time, while FCEVs requires expansion of the hydrogen infrastructure but have greater driving ranges and lower refueling times [200]. Cost and operating parameters for FCEVs, hydrogen production, and hydrogen delivery have been determined by the Department of Energy and the National Renewable Energy Laboratory [201], [202], & [113]. A study by Yazdanie, Noembrini, *et al.* (2016) found that FCEVs had potential to reduce well to wheel energy demand, emissions, and costs compared to BEVs [203]. However, an older study by Eaves and Eaves (2003) compared the manufacturing and refueling costs of FCEVs and BEVs and found that BEVs performed favorably in terms of cost, energy efficiency, weight, and volume [204]. These studies determine the GHG reduction potentials of different technologies, however, primarily focus on one sector, such as transportation or electric sectors, and do not compare the utilization of excess renewable energy for multiple sectors.

2.6.2 Previous Literature on Comparison of technologies

Many studies focus on a review of technology characteristics to compare a wide variety of technologies [92], [205]. A review of different technologies and strategies to utilize variable renewable electricity was considered in a study by Lund, Lindgren, *et al.* (2015) [206]. Another study by Gallo, Simões-Moreira, Costa, *et al*. (2016) considered the different technology characteristics such as power rating, discharge time, and environmental issues of multiple ES technologies and found that no technology had a unilateral advantage over the others, but stated that P2G technologies are promising due to seasonal storage capabilities and the ability to participate in multiple energy markets including the transportation sector [207]. A study that

focused on P2G pathways conducted by Schiebahn, Grube, *et al*. (2015) concluded that renewable hydrogen or methane injected into the natural gas grid has higher production costs than conventional natural gas while renewable hydrogen for FCEVs had the potential to be economically competitive due to the high efficiencies of FCEVs [208]. FCEV and BEV characteristics, such as costs and energy use, were compared in a study by Rosler, Zwann, Keppo, *et al.* [209]. A study by Yang, Zhang, *et al.* (2011) highlights the need for energy storage and discusses a couple battery energy storage technologies in detail: redox flow batteries, sodium-beta alumina membrane batteries, lithium-ion batteries, lead-carbon batteries [210]. A study by Aneke and Wang (2016) considered the real-life applications of ES battery technologies [211]. These studies consider a technological review of technologies which have the potential to reduce GHG emissions however do not model the operational characteristics of the different technology types to store and utilize excess renewable energy in a highly renewable electric grid.

2.6.3 Previous Literature on Capturing and Utilizing Renewable Generation and/or Zero Emission Vehicles to reduce GHG emissions

Renewable generation is difficult to integrate into the electric grid due to variability and intermittency. Studies have reviewed and compared different technologies to reduce GHG emissions or capture renewable generation [92], [205], [206]. Studies found that alternative technologies have a high potential to reduce GHG emissions but without singling any one technology as the sole solution. A study by Gallo, Simões-Moreira, and Costa (2016) [207] which analyzed twenty-eight energy storage (ES) alternatives to determine the wide range of applications. The study concluded that no ES technology outstands all others but rather the

selection of technology should be case-by-case. Evans, Strezov, and Evans (2012) [212] found there is a range of options for storage which are economical depending on each individual need, depending on costs, efficiency, and energy stored. Poullikkas (2013) [213] also found that each energy storage technology type had differing costs and efficiencies which are beneficial in different ancillary services.

However, these studies only examined the technical characteristics of each ES technology and did not model or simulate scenarios. Schill and Zerrahn (2018) [214] found that to reaching RPS goals greater than 80% increasingly requires the need for energy storage. Colbertaldo, Guandalini, and Campanari (2018) [215] modelled the role of hydrogen and P2G for renewable integration and reduction of GHGs. The study found hydrogen was able to increase renewable integration in both the transportation and electricity sector, however, could not obtain the goals for GHG emission reductions for Italy. Blanco and Faaij (2018) [216] reviewed and compared the storage needed for a 100% RPS system with a focus on power to gas. The study found that at RPS less than 30% curtailment is usually the best option while reaching RPS greater than 80% requires storage to reduce overall system costs. Mehrjerdi, Iqbal, and Rakhshani (2019) [217] analyzed a net-zero energy building with renewable generation and hydrogen storage and found that during times of hydro power solar energy was not needed. Studies simulating a highly renewable energy system have also been conducted. A study simulating 100% renewable scenarios of the Australian National Electricity Market was conducted by Ellison, Diesendorf, and MacGill (2012) [218]. The study found a range of 100% renewable energy systems that were technically feasible. However, this study did not limit the use of biogas which was used in gas turbines to balance the electric

grid and did not consider the effects of curtailing ERE. A study by Mac Donald, Clack, and Alexander (2016) [219] found that the US electricity sector's GHG emissions can be reduced by up to 80% of 1990 levels without an increase in cost of electricity.

Other studies have considered the effects of ZEVs to reduce GHG emissions. For example, a study by Shafiei, Leaver, and Davidsdottir (2017) [220] simulates New Zealand's energy and transport system to assess policies promoting the implementation ZEVs to reduce greenhouse gas emissions. This study focuses on ZEVs and how various scenarios resulted in differing GHG mitigation and costs. This study does not consider the GHG emissions from the electricity sector, for producing electricity or hydrogen for the vehicles, or the need for ES. Another study by Shafiei, Davidsdottir, and Leaver (2017) [221] simulated hydrogen and electricity pathways for a carbon neutral transportation sector by banning gasoline vehicles. The study found that BEVs had the best cost-effective measure to reduce GHG emissions but could alone could not satisfy the GHG emission reduction goals compared to BEV and hydrogen pathways. These studies considered the potentials of differing technologies to reduce GHG emissions, but do not model a wide variety of technologies or sectors and primarily focus on one technology or sector.

2.6.4 Previous Literature on Necessary Curtailment to Reduce Costs on the Electric Grid

Studies have found curtailment issues in current day electric grids in California, the United States, and other countries [26], [222], [223]. To reach 100% renewable penetration goals, the need for energy storage is apparent. Research has been conducted to determine the potentials for energy storage to capture and utilize otherwise curtailed renewable generation. In other terms, to capture renewable generation when the demand is low for use later when the demand

is high. A study by Joos and Staffell (2018) found that the costs associated with curtailment were large and primarily due to the reimbursement to the wind generations [224]. However, to reach a system wide high RPS, curtailment could be an optimal solution to achieve system-wide high renewable penetration.

Studies have shown curtailment is a viable option to better integrate renewable generation into the electric grid. A study from Clean Power Research for the Minnesota Department of Commerce and the Minnesota Solar Pathways Project (2018) [225] found an optimal point of curtailment which resulting in the lowest generation cost. The Minnesota Solar Pathways Project (2018) [225] found that over-building wind and solar capacity to allow a 50% curtailment of renewable generation yielded the lowest system-wide generation cost to achieve the goal of meeting 70% of the regional electric load with wind and solar by 2050. This study also found that disallowing curtailment would require long term or seasonal storage, resulting in larger ES and higher costs, but it only considered short-duration battery technologies for ES. A study by Jacobsen and Schröder (2012) [226] found that curtailment of renewable energy can be optimal. The study found that completely avoiding curtailment could lead to extremely high costs to reach higher integration of fluctuating renewable generation. A study by Schill (2014) [227] optimized the Germany electric grid at different renewable penetration levels which found allowing small amounts of curtailment could potentially negate the need for energy storage at lower renewable penetration levels. The study also found when reaching higher renewable storage capacities energy storage is required for seasonal storage. However, the amount of curtailment in this study was not optimized based on costs but rather based on restrictions of

percent of yearly generation and the amount of renewable capacity was set and not spanned. This forces the optimization to not curtail the renewable electricity even when it may be more economical to install more renewable capacity.

2.6.5 Previous Literature on Cost of Carbon

Climate change causes significant economic losses, currently valued at $125 billion annually with projections of $600 billion per year by 2030 [228]. Therefore, it is important to consider the cost of GHG emission reductions through the introduction of more environmentally benign technologies. A study by Rubin, Davison, and Herzog (2015) assessed the costs of CO_2 capture and storage for new fossil fuel power plants, an update from the costs reported in the 2005 Intergovernmental Panel on Climate Change's Special Report on Carbon Dioxide Capture and Storage [229], [230]. The study found that carbon prices of $50-$100 per ton of carbon are necessary to influence commercial markets for carbon capture. A study by Sims and Rogner (2003) considered the cost of CO_2 emission reductions for electricity production, such as renewable generation as well as carbon capture with conventional natural gas generation [231]. A study by William, DeBenedictis, *et al*. (2012) considered the infrastructure and technology path to meet the goal of 80% GHG reduction below 1990 levels [232]. A study by Marcantonini and Ellerman (2013) found that the cost of CO_2 reduction was around tens of dollars per ton of CO_2 for wind energy and above $600 per ton of CO_2 for solar energy [233]. However, another study by Viebahn, Daniel, and Samuel found that carbon capture and storage may not be necessary in a future with high integration of renewable energy [234]. These studies only focus on the costs

of one technology to reduce GHG emissions and do not consider the system wide cost reductions from introducing technologies which reduce GHG emissions by utilizing excess renewable energy.

The social cost of carbon determined by the Interagency Working Group on Social Cost of Greenhouse Gases (2015) range from $26 to $212 per metric ton of CO_2 for year 2050 [235]. This social cost of carbon is an estimation for the social benefits of reducing CO_2 emissions for government agencies to consider as a cost-benefit. The U.S. Energy Information Administration considered a fee for CO_2 emissions around $10 to $25 per metric ton to promote the use of renewable energy sources and decrease the demand of fossil fuels [236]. This fee for CO_2 emissions is projected to decrease CO_2 emissions relative to a case without implementing the CO_2 emission fee; however, the projected results show minimal CO_2 emission reductions which proves that a higher fee is necessary to significantly decrease emissions. And, the fee is much lower than the projected costs to reduce CO_2 emissions.

2.7 Research Gap

There have been many studies which consider the different energy sectors: electricity, transportation, and natural gas and how the capture of ERE can reduce GHG emissions from the energy systems. However, there are some gaps to fully understand the cost-optimal technology pathway for each of the energy sectors to reach GHG emission reductions. The gaps in the literature are:

- Studies in literature focus on individual technology's impact on the energy system. However, different technologies will be deployed and dispatched simultaneously to utilize ERE for GHG emission reductions. The technologies have different operational

characteristics, flexibility, efficiencies, and costs which could determine how best to operate them. The cost optimal technology portfolio and understanding the driving characteristics for the selection of such a portfolio has not been assessed in the future.

- Studies in literature also focus on one or two, but rarely all three of the most prevalent energy sectors: electricity, transportation, and natural gas. These studies provide a useful understanding of technology characterization and how technologies for each sector differ. However, there is a lack of research on combining all these sectors together as goals to reduce GHG emissions require the interlacing of the different sectors with the electricity sector due to renewable energy being the primary carbon free energy source.
- Studies in literature have demonstrated that renewable curtailment is preferable than attempting to capture all the renewable generation with energy storage or P2G technologies. However, there is not a clear understanding of how much curtailment of renewable generation is cost-optimal to reach California's electricity goals. There is a gap in literature understanding the cost benefits of installing more renewable capacity versus installing more energy storage technologies.

Table 5 represents relevant literature and how there are many studies that look at carbon emissions and costs, but not all optimization of energy storage for the electric grid, zero emission vehicles for transportation, or P2G for integration of renewable energy to the natural gas sector.

Table 5: Relevant literature in the investigation of energy storage, transportation, and P2G.

Author	Year	Scope	Modeling	Carbon Emissions	Equipment Costs	Source

Kalantar, et al. [237]	2010	Energy Storage	Technology Sizing Optimization	No	Yes	Applied Energy
Gallo, et al. [207]	2016	Energy Storage	-	No	No	Renewable and Sustainable Energy Reviews
Forrest, et al. [154]	2016	Energy Storage and Transportation	Vehicle Charging Optimization	No	No	Journal of Power Sources
Shafiei, et al. [220]	2017	Transportation	Simulation of System Dynamics	Yes	Yes	Journal of Cleaner Production
McPherson, et al. [194]	2018	Energy Storage	Balancing System Dynamics Optimization	Yes	Yes	Applied Energy
Arciniegas, et al. [193]	2018	Energy Storage	Operation Optimization	Yes	Yes	Energy
Colbertaldo, et al. [215]	2018	Energy Storage and Transportation	Simulation of System Dynamics	Yes	Yes	Energy
Gopal, et al. [238]	2018	Transportation	-	Yes	Yes	Transportation Research
Lewandowska-Bernat, et al. [239]	2018	Power-to-Gas	-	Yes	Yes	Applied Energy
Samsatli, et al. [191]	2019	Energy Storage and Heating	Spatio-temporal Optimization	Yes	Yes	Applied Energy
Maroufmashat, et. al. [240]	2016	Energy Storage and Transportation	Technology Sizing Optimization	No	Yes	2016 IEEE SEGE

One of the most prominent policy used models is the E3 RESOLVE and PATHWAYS model. The RESOLVE model is a capacity expansion model that projects the future California electric grid from 2017 to 2050 [241]. However, the model does not consider long duration storage and is

limited to 37 representative days in the year. The model also does not consider hydrogen as a dispatchable energy storage and rather only as fuel production demand.

3 APPROACH

The goal of this dissertation is to establish technology portfolios that can utilize excess renewable electricity to allow for renewable penetration into the electricity, transportation, and natural gas sectors. This work develops a methodology to characterize and understand the various levels of renewable integration based on stated system goals. The result of this work will inform industry and policy makers which technologies how those technologies operate in tandem with the renewable generation and other technologies. Particularly, the focus is not on the technologies themselves but rather their operation in comparison and in unison with other technologies, as the exact economic and technologic parameters are projected so far into the future it's difficult to ascertain the certainty of the outcome. Therefore, a sensitivity analysis will better understand how sensitive the technology selection is dependent on the projected cost.

3.1 Tasks

To achieve the dissertation goals, the following tasks are completed.

Task 1: Collect data for end-use demand, collect data for new technology parameters and costs, update parameters and costs for existing generation technologies.

An understanding and collection of models and a literature review of the various considered sectors and technologies is required.

The HiGRID model is a previously existing model that has been used extensively to explore the integration of renewable electricity generation into the electric grid. The HiGRID model needed to be altered to allow for this analysis which involved extensive research and review of

the HiGRID model as well as an update of the previously existing cost assumptions. Literature review is also necessary to set up the cost analysis and annual and hourly profiles conducted in the following tasks. These costs are crucial for the analysis conducted in this dissertation, as the primary method to compare between the different technology types are based on costs.

Task 2: Conduct analysis on individual technology pathways on the California electric grid.

This task utilizes the HiGRID model to understand the differences of the various technology pathways. The purpose of this analysis is to both understand and review the HiGRID model as well as the various technology pathways without optimization. This will provide insight without the influence of an optimization which is dependent on the assumptions such as cost and operational parameters, such as efficiency or limitations.

Task 3: Develop an optimization model which utilizes excess renewable electricity for different end-use systems.

This task focuses on the development of the optimization model to determine the least-cost use of ERE to meet California's goals. The constraints and objective function are discussed in detail as well as the integration with HiGRID. The constraints are primarily based on the annual and hourly profiles established in Task 1 as well as any technology operational constraints. The objective function is based on the costs determined from Task 1.

Task 4: Evaluate and conduct a single representative year analysis for cost optimized portfolios for years 2030 and 2045.

The purpose of this task is to conduct single representative year analysis to determine the solution to the optimization model developed in Task 3. This will determine the least-cost technology portfolios that are required to achieve the 2030 and 2045 goals of 60% RPS and zero carbon electric grid, respectively. There are various scenarios considered such as the use of renewable gas natural gas power plants and considering the cost of carbon to weight carbon emissions to cost. The results are presented in both an annual basis, to compare between different availabilities of renewable generation, and hourly, to compare the hourly operation between the different technology types.

Task 5: Evaluate various scenarios and sensitivity analysis for the optimal technology portfolio.

This task is to evaluate various scenarios and analyze the various results of the optimization. The optimization model developed in Task 3 and the results from Task 4 were used as a basis for the scenarios. Such scenarios include a sensitivity analysis on the cost and efficiency of the various technology types, the limitation of fuel cell and NGPP ramping operation (that wasn't considered in Task 4), and the assumption for the energy storage state of charge outlined in Task 3.

Task 6: Evaluate the transition of the technology portfolio for achieving California's goals from 2030 to 2045.

Task 4 and 5 focus on the optimization of a single representative year. The purpose of this task is to conduct a multi-year analysis optimization the dispatch of technologies from 2030 to 2045 to meet California's goals. This task also takes the least-cost scenario determined from Task 4 to determine the renewable generation for the different years.

4 TASK 1 – Model Update and Data Collection

4.1 Holistic Grid Resource Integration and Development Tool (HiGRID)

4.1.1 Description of HiGRID Modeling

HiGRID has been used in previous investigations to determine the effects of renewable integration on the electricity generation technology mix on the grid [154], [192], [242]. The HiGRID model determines the response and dispatch of electric grid resources to balance load and generation on the electric grid while meeting the dynamic constraints of different resources and the needs for ancillary services. The resources modeled include but are not limited to renewable generation options (solar, wind, geothermal, biogas), dispatchable generation (hydropower, load-following and peaking power plants), base-load generation (nuclear), and dispatchable technologies such as energy storage, demand response, hydrogen production, and electric vehicle charging. As outputs, the HiGRID model produces the hourly temporal behavior of every grid resource installed in a scenario along with system wide GHG and criteria pollutant emissions, and the LCOE. An overview of HiGRID can be seen in Figure 12.

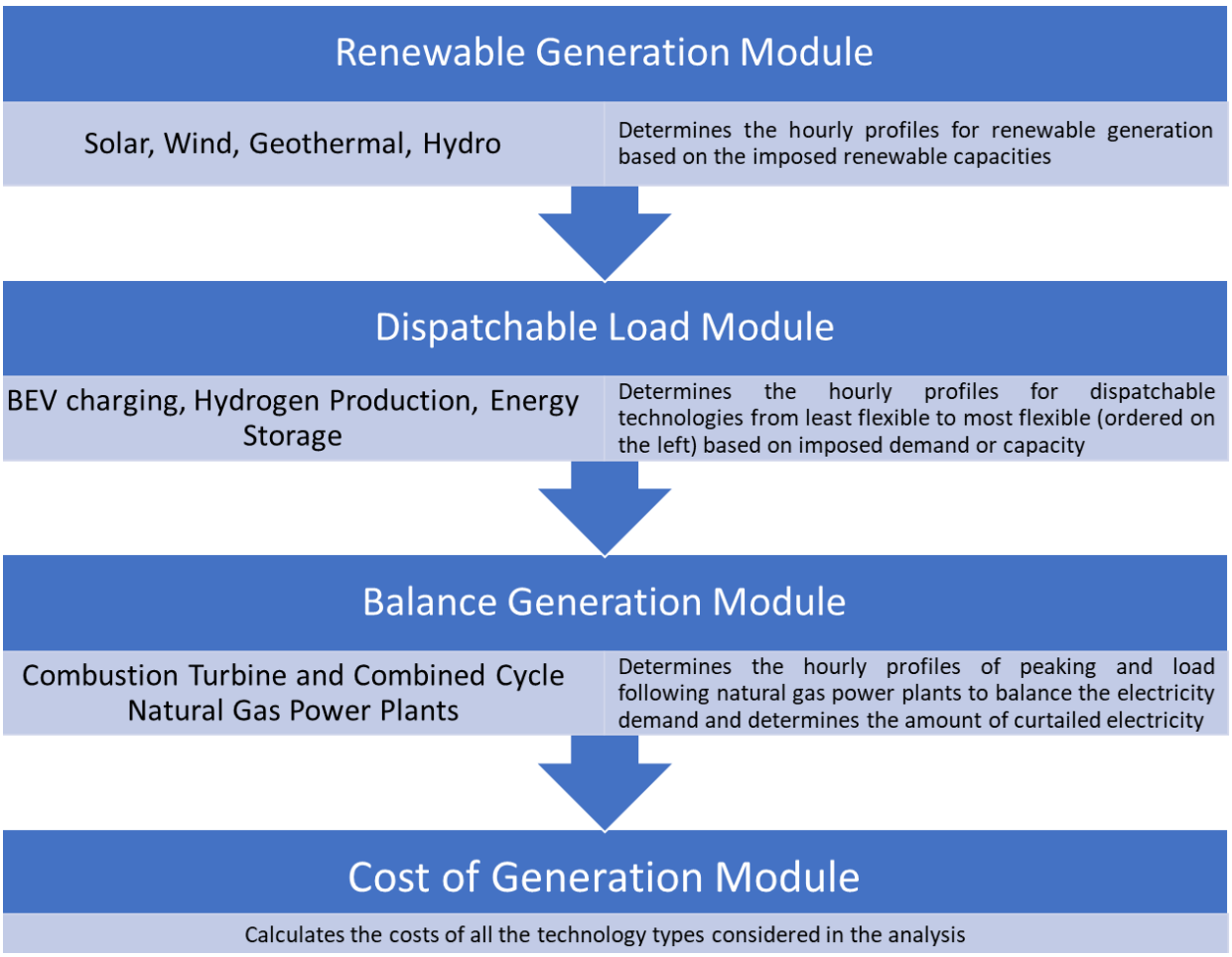

Figure 12: A description of the HiGRID model.

A more detailed explanation of HiGRID can be found in papers by Shaffer, Tarroja, and Samuelsen (2015) and Eichman, Mueller, and Tarroja (2013) [243], [21]. HiGRID consists of four primary modules, briefly described as follows:

The first module is the Renewable Generation Module, which utilizes the output of physical models for renewable generation technologies to determine an hourly-resolved aggregate renewable generation profile. Included technologies are rooftop solar PV, centralized (large plant) solar thermal, onshore wind, small hydropower, and biogas. Solar PV profiles were

developed from insolation data by the National Solar Radiation Database [244] in different regions of the state and equivalent circuit models of solar photovoltaic panels, validated with actual solar PV power data. Solar thermal profiles were developed from thermodynamic modeling of solar collectors and closed-loop steam-based power plants based on actual plant operating data presented by Bialobrezeski (2007) [245]. Wind power profiles were obtained from the National Renewable Energy Laboratory (NREL) Western Wind and Solar Integration project [246], which determined wind speeds and hourly generation potential in spatially-resolved grids across California, using turbines with hub heights of 100 meters. Geothermal is modeled as a base-load technology with a capacity factor of 85%, limited in capacity by that specified by the U.S. Geographical Survey for the California region [247]. Biogas is used as a replacement for conventional natural gas in gas turbine power plants. The hydropower reservoir module determines the power generation for large storage capacity hydropower units and is dispatched to minimize spillage and satisfy reservoir demand, capacity, and flood control constraints [181], [248].

The second module is the Dispatchable Load Module, which models the dispatch of technologies installed in the electric grid that can satisfy components of the electric load demand in a time-varying manner. This module takes as input the net load profile, calculated as the electric grid load minus the aggregate renewable generation profile from the Renewable Generation Module. Within the Dispatchable Generation Module are:

- ES sub-module: Stores electricity and discharges it back to the electric grid through electric batteries or hydrogen into fuel cells to prioritize smoothing out the net electric

load by charging during times of low net load and discharging during times of high net load [47], as constrained by energy and power capacity limits as well as ramping limits. The model distinguishes BES pathways and HES pathways based on overall efficiency, the ratio of discharged versus charged electricity, and storage capacities.

- Hydrogen electrolysis dispatch sub-module: Determines the amount of hydrogen produced for use as a transportation fuel and for renewable natural gas production and the temporal profile of the hydrogen electrolysis load. This module dispatches electrolyzer units to provide a valley-filling function for the net load profile to minimize and utilize excess renewable generation by producing hydrogen during times of low or negative net load [249]. Some updates were required to allow this model to better match renewable generation while optimizing the operation of the electrolyzers to have higher capacity factors.
- BEV sub-module: Determines the operation of charging BEVs – Immediate, Smart, or V2G. These strategies utilize a linear optimization approach to determine the optimal time for BEVs to charge based on a cost function represented by the input net load profile. These charging strategies have been implemented in HiGRID and used in previous analyses that describe their detail [154].

The third module is the Balancing Generation Module, which determines the dispatch of controllable resources in response to the needs represented by the net load profile and remaining ancillary service requirements, within the constraints of energy resource availability, peak capacity limits, start-up/shut-down constraints, and ramping constraints on the included

resources. These resources are dispatched by default to minimize the number of start-up events for controllable power plants while subject to the previously mentioned constraints. As an output of this module, the temporal generation profiles and required installed capacities of balancing power plants such as gas turbines, fuel cells, large hydropower, and combined cycle systems as appropriate are produced.

The fourth module is the Cost of Electricity Module, which takes as inputs the capacities and temporal generation profiles of the grid resources as calculated in the previous three modules and uses cost inputs for capital costs, operation and maintenance costs, taxes, incentives, and other factors on a resource-specific basis to calculate the levelized cost of electricity for each grid resource and for the grid as a whole.

4.1.2 Changes to the HiGRID Model

A few simple changes were required of the HiGRID model for two different types of operation.

1. The first operation of HiGRID used in this dissertation is the individual technology pathways analysis. This utilizes the native HiGRID model, described in the previous section, with little changes. The changes are primarily for the integration of technologies that were not previously considered, such as fuel cell and electrolyzers for hydrogen energy storage and injection of renewable gas into the natural gas system. There was little need for configurations in the HiGRID model logic, the primary change in HiGRID was the unit conversions for the cost calculation.

The HiGRID Cost of Generation (COG) Module was previously made by Dr. Josh Eichman and Dr. Lori Schell based on the CEC Cost of Generation Module [250], [251]. The COG Module does not consider the use of fuel produced from the HiGRID model. All fuel costs and availability are dependent on static inputs. To determine the COG for technologies which utilize fuel produced from HiGRID technologies, such as electricity or hydrogen, an update to the COG Module is required. A calculation to determine the non-levelized, non-discounted cost of energy for hydrogen and electricity is required. The newly defined undiscounted costs allow to be used as input for technologies which use the fuel: electricity for electrolyzers or electrical energy storage; hydrogen for fuel cells, Fuel Cell Electric Vehicles, or input into the natural gas; as well as any other potential fuels which could be produced such as methane or renewable fuels. See the following Figure 13 for the Matlab code. The code represents the additive to the existing COG Module which calculates the undiscounted cost as well as calculation to add the cost of storage to the cost of hydrogen from the electrolyzers. The COG Module calculates the cost of energy for each technology in sequential order. Thus, the electrolyzers are placed before the hydrogen energy storage (HES) to calculate the $/kg of hydrogen considering the cost of electrolyzers and the HES. Consequently, the cost of energy for the fuel cells, hydrogen fueling stations, and injection into the natural gas pipeline take in the $/kg of hydrogen after the HES as fuel.

```
%% Calculate total cost-of-x (undiscounted)
% in %/kw-yr for gen_tech = kk based on aggregated values that combine
% renewable and non-reneawble components
% if gen_tech == smw_methanator %Methanator has methane as the output
%     mwh_annual_load_coe_calc = methane_produced(smw_methanator,:); %calculated from hydrogen_produced
% else
    mwh_annual_load_coe_calc = mwh_annual_load;
% end
coe_annual_kw_yr = after_tax_net_inc_kw_yr + fixed_op_costs_kw_yr...
    + var_costs_kw_yr + state_tax_kw_yr + fed_tax_kw_yr;
coe_annual_mwh(kk,1:econ_life) = kw_yr_to_mwh(gross_cap, mwh_annual_load_coe_calc, coe_annual_kw_yr);
mwh_annual_load_save(kk,1:econ_life) = mwh_annual_load;

if LCORE ~= 1
    if any(gen_tech == smw_methanator ) == 1
        coe_renewable_methane(gen_tech,1:econ_life) = coe_annual_mwh(gen_tech,1:econ_life);
    elseif any(gen_tech == smw_EC_tech) == 1
        coe_renewable_hydrogen(gen_tech,1:econ_life) = coe_annual_mwh(gen_tech,1:econ_life);
        renewable_hydrogen_cost_for_UHM(1,gen_tech) = coe_annual_mwh(gen_tech,1);
        hydrogen_produced_cost_module_for_UHM(1,gen_tech) = mwh_annual_load(1);
        hydrogen_produced_cost_module(gen_tech,:) = mwh_annual_load;
    elseif any(gen_tech == smw_HES_techs) == 1
        coe_renewable_hydrogen(1:min(smw_HES_techs)-1,1:econ_life) = zeros(min(smw_HES_techs)-1,econ_life);
        hydrogen_produced_cost_module(1:min(smw_HES_techs)-1,1:econ_life) = zeros(min(smw_HES_techs)-1,econ_life);

        coe_renewable_hydrogen(gen_tech,1:econ_life) = coe_annual_mwh(gen_tech,1:econ_life);
        hydrogen_produced_cost_module(gen_tech,:) = mwh_annual_load;
    end
else
    if gen_tech == smw_methanator
        coe_renewable_methane(gen_tech,:) = zeros(1,100);
    elseif gen_tech == smw_EC_tech
        coe_renewable_hydrogen(gen_tech,1:econ_life) = zeros(1,econ_life);
        hydrogen_produced_cost_module(gen_tech,:) = zeros(1,100);
    end
end
```

Figure 13: Example Matlab code to calculate for undiscounted fuels produced within from grid technologies.

2. The second operation of HiGRID is to work in tandem with the developed optimization model, later described in more detail in Task 3. HiGRID is primarily utilized to initialize the optimization model. The renewable generation module is used to determine the hourly profile of renewable generation from solar, wind, geothermal, and hydropower. The total renewable generation and the electric demand is used to determine the net load. The negative portion of the net load determines the availability of ERE and the positive portion of the net load determines the required dispatchable electricity generation. In this second

operation of HiGRID, the Dispatchable Load Module and the Balancing Generation Module are replaced by the optimization model.

4.2 Energy and Environmental Economics PATHWAYS

Many parameters used are adopted from the E3 PATHWAYS study [252] [253]. The PATHWAYS study developed and investigated a range of technology and demand scenarios for achieving an economy-wide (including non-electricity sectors) 80% reduction in GHG emissions in California below 1990 levels by 2050. The E3 PATHWAYS parameters for load growth and profiles for residential, commercial, and industrial sectors, transportation electrification, and the ratio of wind to solar capacity are used as inputs. The outcomes of the PATHWAYS model provide plausible information particularly for characterizing load growth, load profiles, and a plausible percentage mix of renewable resources. For this study, we adopt parameters for load growth by sector, load profiles for residential, commercial, and industrial sectors, transportation electrification, and the ratio of wind to solar capacity.

4.2.1 Example Inputs for 2045

To simulate the operation of a zero-carbon electric grid in the year 2045, certain parameters are based for the state of the electric grid in 2045 based on information from the E3 PATHWAYS study [253]. The PATHWAYS study developed and investigated a range of technology and demand scenarios for achieving an economy-wide (including non-electricity sectors) reduction in greenhouse gas emissions in California of 80% below year 1990 levels by 2050. These are specified as follows:

Table 6: Common load parameters applied in the development of all zero-carbon compliant scenarios for California

Sector	**Year 2045 Annual Electric Load Magnitude [GWh]**	**Modeling Notes**
Residential	112,088	Profile from E3 PATHWAYS Study
Commercial	122,956	Profile from E3 PATHWAYS Study
Industrial	74,413	Profile from E3 PATHWAYS Study
Transportation - Light Duty Electric Vehicles	46,862	Fixed profile based on travel survey data as modeled by Tarroja [242]. Accounts for load associated with 15.2 million BEVs and 10.5 million PHEVs
Transportation - Other Electric Vehicles	34,400	Profile from E3 PATHWAYS study – fixed profile with immediate charging
Transportation – Hydrogen Production	38,050	Dispatchable electrolysis with injection into pipeline, as modeled by Tarroja [242]. Accounts for load associated with 4.56 million light-duty FCEVs, 64,000 medium-duty FCEVs, and 46,600 heavy-duty FCEVs with profile from Chevron fueling station [254].

Table 7: Percentage Contribution by Capacity of Variable Renewable Resource Mix from E3 PATHWAYS

Variable Renewable Resource Type	**Percentage of Total Variable Renewable Mix by Installed Capacity [%]**

Onshore Wind	34.4%
Rooftop PV	17.9%
Utility-Scale PV	47.7%

Table 8: Installed Capacity of Dispatchable Zero-Carbon Resources from E3 PATHWAYS

Dispatchable Zero-Carbon Resource Type	**Installed Capacity [GW]**
Hydropower (Aggregated – Large and Small)	15.6
Geothermal	4.46
Nuclear	0.00
Biomass	0.00

The inputs for other years can be found in APPENDIX B.

4.3 Acquiring end-use demand

The end-use demand for hydrogen fueling stations were based on the operation of a Chevron estimate of station dispensing volume [255]. The operation of the gasoline station is based off a typical station that serves both light and heavy-duty vehicles. In this research, the demand for both light and heavy-duty vehicles are not differentiated for hydrogen fueling stations. The hourly, weekly, and daily profiles were taken and normalized to determine the daily hydrogen dispensing profile for hydrogen vehicles, see Figure 14 for an example. The dispensing of the fueling station is smooth and diurnal which does not represent a single gasoline station, the profile is used for the entire state of California. This profile is multiplied by the total energy

demand for hydrogen to meet the total vehicle miles in California. The analysis thereafter determines the percentage of the fleet which is met by FCEVs to determine the true hourly hydrogen demand.

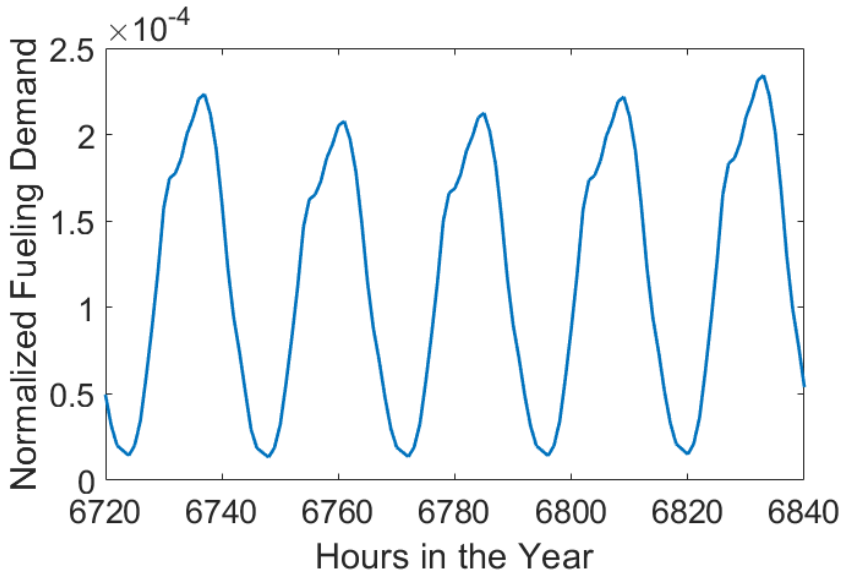

Figure 14: Example of normalized hydrogen station dispensing profile for a Fuel Cell Electric Vehicle demand.

The end-use demand for natural gas were based on the consumption of pipeline natural gas delivered to consumers in California [256]. The normalized hourly natural gas demand for one year is shown in Figure 15. This shows how the natural gas varies throughout the entire year per month. This normalized profile is then multiplied by the annual demand to determine the hourly profile of natural gas use. The natural gas demand is primarily to determine the potential hydrogen and renewable methane demand that is used for non-electrical end-uses. It is also used to ensure that the hydrogen mixture into the natural gas pipeline does not exceed a 20% mix by volume [136], [257]. Although, there was no spatial consideration into where the hydrogen was injected into the natural gas pipeline. The purpose of this research was to consider California as

a whole and to see whether it's feasible from a system-wide perspective to inject renewable hydrogen or methane into the natural gas pipeline to provide renewable energy to the natural gas system.

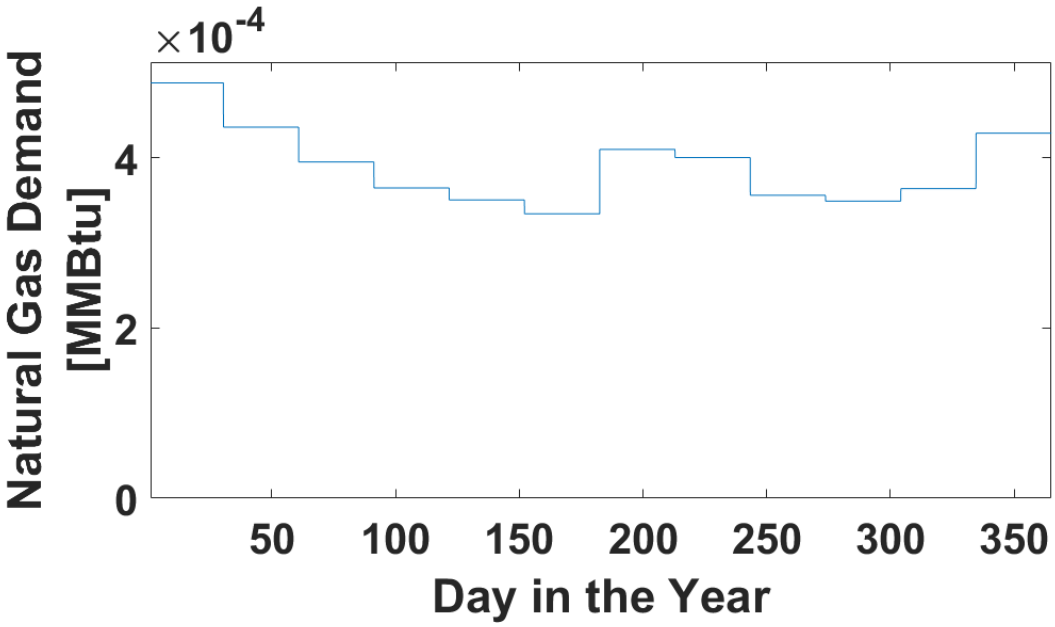

Figure 15: The hourly natural gas demand, varying per month, for the whole year.

The electric vehicle demand was determined based on a previous study conducted by Forrest [258]. The light duty electric vehicle demand is largely based off human pattern of charging when the owners are home from work, with a slight peak in the morning and a larger peak in the afternoon after work, seen in Figure 16. The figure represents a normalized day. The annual normalized demand is multiplied by the total energy demand to determine the total electricity profile if all vehicles were electric vehicles. This demand will be used in the analysis as a portion depending on the penetration of electric vehicles. The heavy-duty vehicles have a similar pattern.

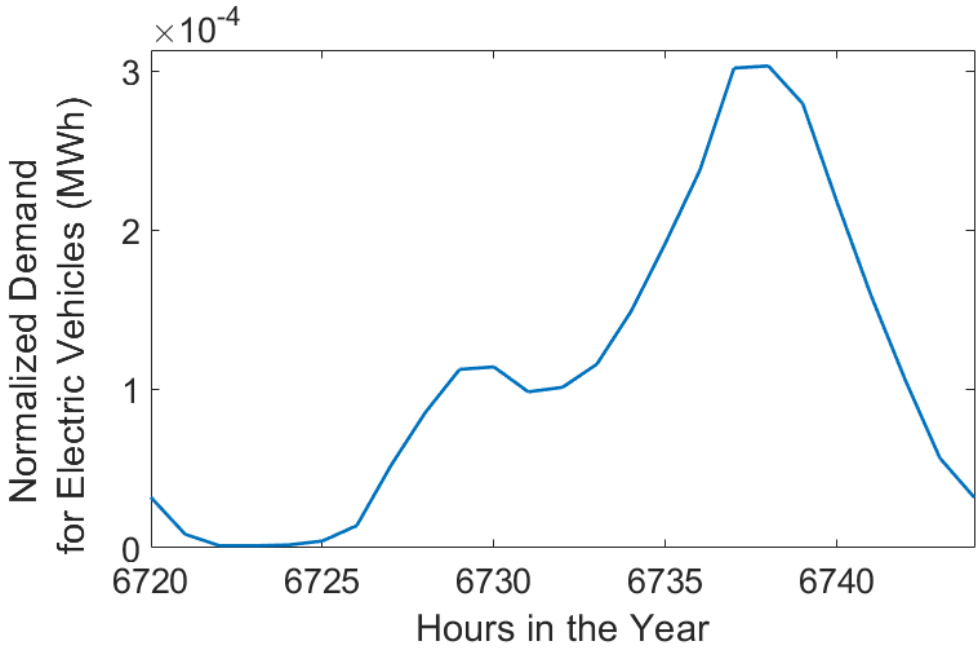

Figure 16: An example of the normalized electric vehicle hourly demand.

The hourly electric demand was determined from E3. An example of the electric demand can be seen in Figure 17. This figure showcases one day's worth of electric demand starting from 12am to 12am the next day, 0 to 24 hours. This pattern is the net load without renewables, so there isn't a valley in the middle of the day, with low electric demand during the night with a slight rise in the morning, consistent demand through noon, and a peak afternoon. This electric demand profile, as stated before, raises issues with the reliance on solar generation, as solar does not generate during the peak time. The hourly electric demand for the entire year is also seen in Figure 18. There are slight variations every week and some seasonal variation, with peaks through days 200 to 280 which correlates to July to September, the hottest time of the year in California.

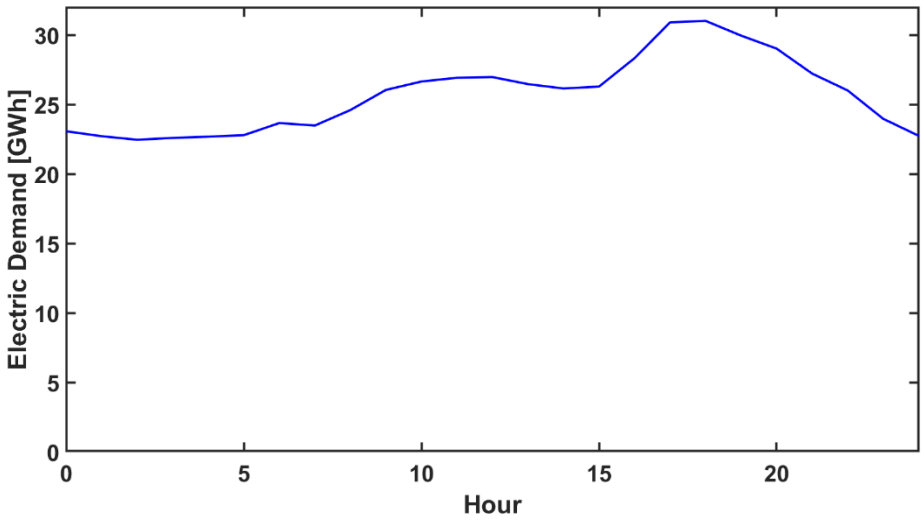

Figure 17: An example of the one day's electric demand.

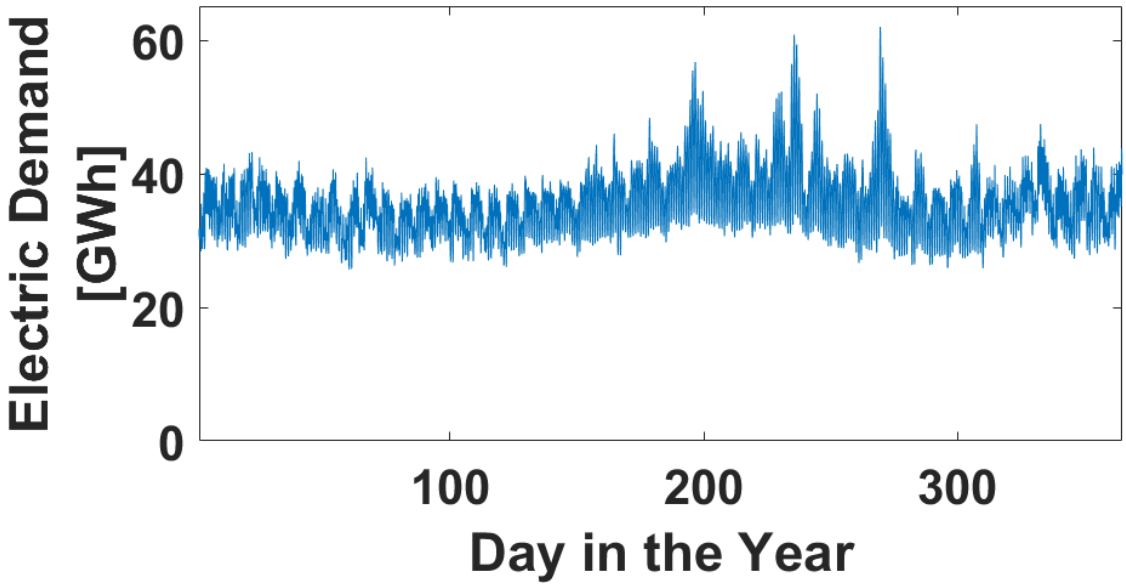

Figure 18: An example of the hourly electric demand for an entire year.

4.4 Acquiring technology parameters and costs

The cost assumptions for the different technologies that can capture ERE for useful purposes are obtained from a variety of sources. The electricity sector values for renewable generation and natural gas technologies come from the NREL's Annual Technology Baseline (ATB) for the electricity sector [259]. The input fuel cost for steam methane reformation (SMR) is based on a study by the US Driving Research and Innovation for Vehicle Efficiency and Energy Sustainability [260] which is extrapolated based on natural gas price projections [261]. SMR is assumed to be run as baseload [262]. The cost and economic assumptions for energy storage and hydrogen technologies come from a variety of sources such as the U.S. Department of Energy [122], [263]. The costs are presented in APPENDIX C for all the different Tasks. A sensitivity analysis is also conducted to determine the leading factors that contribute to the selection of a technology.

5 TASK 2 – Individual Technology Pathways Analysis

The approach and methodology used to carry out the individual technology pathway analysis are taken from a paper by Wang, Tarroja, and Schell (2019) [264], which was published in a special issue of Applied Energy titled: SI: Progress in Applied Energy, and is as follows.

The goal of this analysis is to determine the effects of individual technology pathways on reducing GHG emissions and the associated costs. First, the renewable resource mixes that achieve a 70% RPS and 80% RPS on the year 2050 electric grid are determined. Second, the

following end-uses for harnessing and utilizing excess renewable electricity generation are considered and implemented on the electric grid:

- Battery or hydrogen energy storage for discharge back to the electric
- Production of renewable gas
- Production of transportation fuel for FCEVs or electricity for charging BEVs

Finally, the change in greenhouse gas emissions and cost of energy from the renewables-only cases due to implementing each of these end uses is determined and compared. An overview of the study methodology is presented in Figure 19.

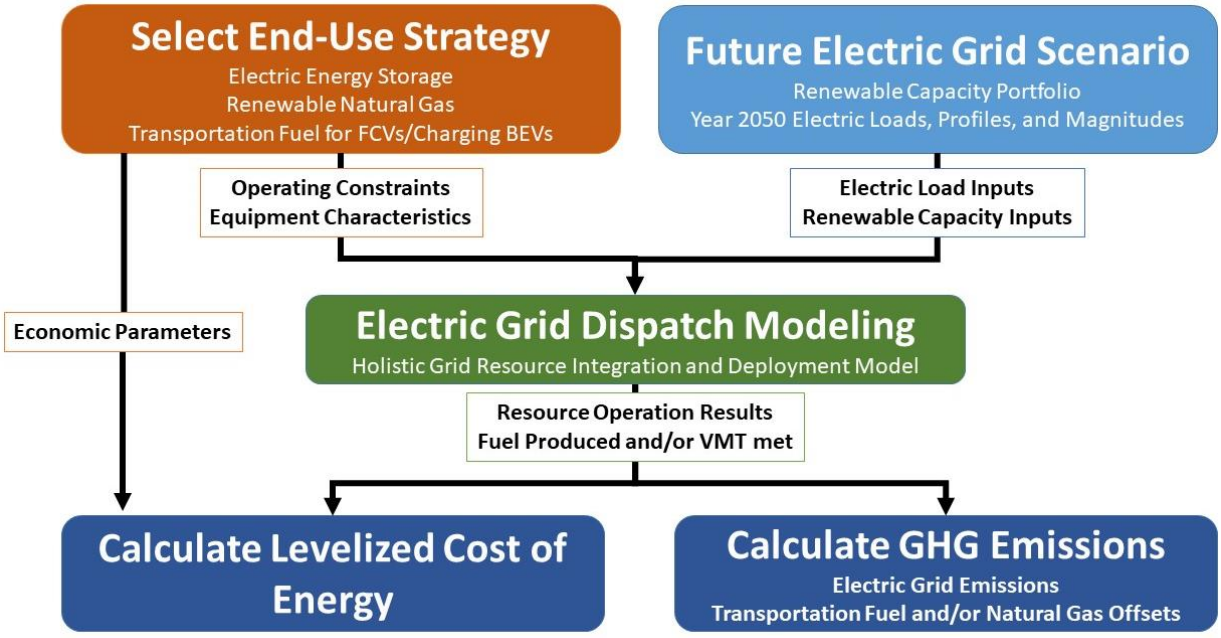

Figure 19: An overview of the study methodology.

Each end-use has multiple technology pathways by which they can be implemented, each of which is analyzed and compared. For each technology pathway, information regarding its technical and economic parameters are obtained. Technical characteristics and operating

constraints for the relevant portfolio of equipment in each strategy-technology configuration are modeled and integrated into the HiGRID electric grid dispatch modeling platform. The HiGRID model is then used to simulate the behavior of electric grid resources under a future renewable resource configuration including the implementation of the technologies aimed to utilize excess renewable generation. As outputs from the HiGRID model, the temporal operating profiles and GHG emissions of every category of grid resource is obtained, as is the levelized cost of energy (LCOE) and the amount of fuel produced or vehicle miles traveled (VMT) satisfied by the additional use of excess renewable generation. Each of the end-use strategies and corresponding technology pathways considered in this study are summarized in Table 9 and the technology parameters and costs can be found in Task 2 Technology Parameters in APPENDIX C. More detail on each of the steps of the overall methodology will be described in the following sections.

Table 9: Corresponding technology for each end use.

Excess Renewable Energy End-Use	**Technology Pathway**	
	Pathway	**Equipment Type**
Renewable Natural Gas Production	Renewable Hydrogen or Renewable Methane Production	Electrolyzers (ECs): Alkaline (AEC) Solid Oxide (SOEC) Proton Exchange Membrane (PEMEC) Methanation Equipment
Storage for discharge back to electric grid	Hydrogen Energy Storage	Electrolyzers: AEC

	(Combination of Electrolyzers + Fuel Cells)	SOEC PEMEC Fuel Cells (FCs): Phosphoric Acid (PAFC) Solid Oxide (SOFC) Proton Exchange Membrane (PEMFC) Molten Carbonate (MCFC)
	Battery Energy Storage	Electric Batteries: Lithium-Ion (Li-Ion) Sodium-Sulfur (Na-S) Advanced Lead Acid (Pb Acid) Zinc-Bromide Flow Battery (ZnBr)
Used as Transportation Fuel	Hydrogen Production for Fuel Cell Electric Vehicles	Electrolyzers: AEC SOEC PEMEC Hydrogen Distribution Method: Gaseous Offsite Production Liquid Offsite Production Gaseous Onsite Production
	Battery Electric Vehicles	Charging Power: Level I (Lvl I)

	(Combination of Charging Power + Management)	Level II (Lvl II) Level III (Lvl III) Charging Management: Immediate (I-BEV) Smart (S-BEV) Vehicle-to-Grid (V2G-BEV)

5.1 Description of End-Use Strategies

Three different end-use strategies for utilizing excess renewable generation were examined. The first is electricity storage and shifting with energy storage, which consists of either HES or batteries (BES) energy storage. The second is the production of renewable gas to offset conventional natural gas usage. The third is utilization as transportation fuel, either to produce hydrogen for FCEVs or to charge BEVs. The different technology pathways per end-use scenario have different inputs such as efficiency, economic, and operational parameters.

A visualization of the end-use scenarios can be seen in Figure 20. Excess renewable electricity can be stored in stationary batteries for later use, used to charge BEVs, or used to produce hydrogen. The produced hydrogen has the potential to support multiple energy sectors, including electricity, heating, and transportation. Hydrogen can be stored for later electricity production by a fuel cell during times of high net load, directly used or converted to methane to offset burning natural gas or used as transportation fuel in FCEVs.

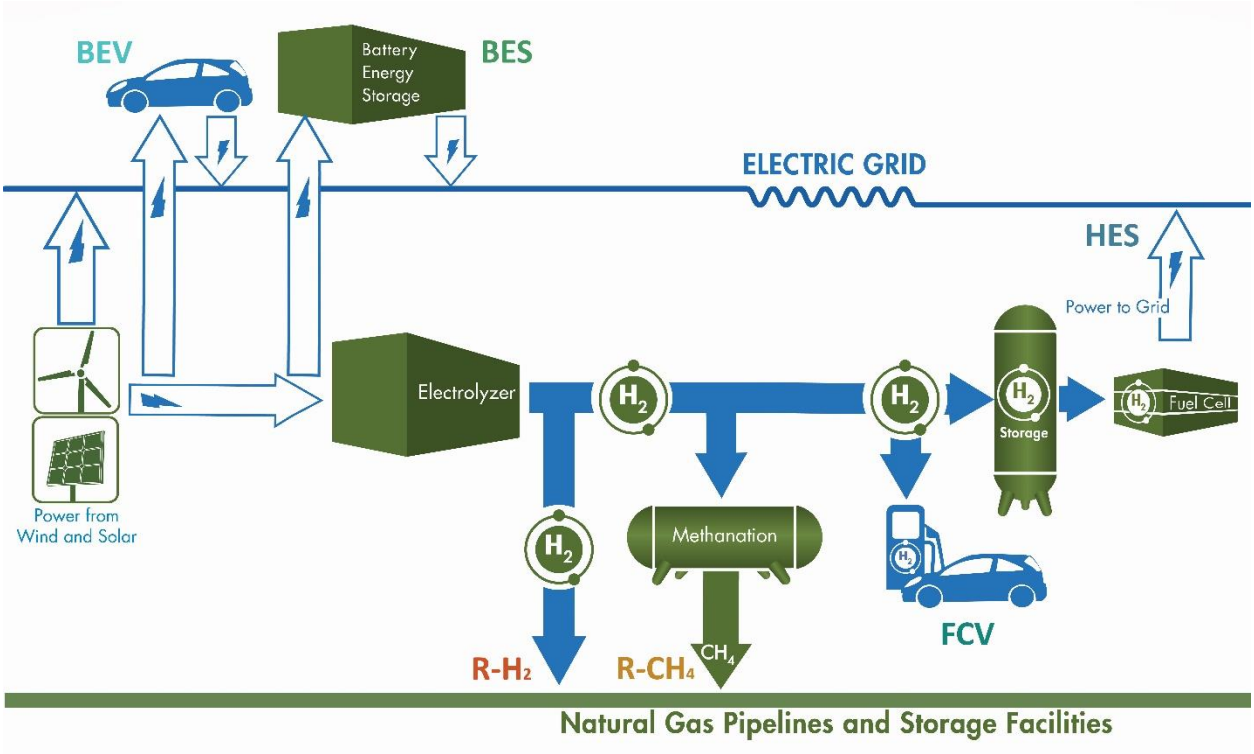

Figure 20: A diagram of the end-use scenarios utilizing excess renewable energy, such as from wind and solar. R-H_2 - Renewable Hydrogen End-Use; R-CH_4 - Renewable Methane End-Use; HES – Hydrogen Energy Storage End-Use; BES – Battery Energy Storage End-Use; FCEV – Fueling for FCEVs End-Use; BEV – Charging for BEVs End-Use.

5.1.1 Energy Storage for Discharge back to the Electric Grid

The ES end-use scenario is composed of HES pathways and BES pathways. Due to the limitation of battery technologies in providing long duration storage, BES pathways are assumed have a rated discharge time of 8 hours, while providing peak load shaving capabilities [265]. The HES pathways tend to have lower round trip efficiencies compared to batteries due to efficiency losses over multiple energy conversion steps. However, HES systems are capable of storage large

amounts of energy by leveraging the natural gas pipeline as a storage medium for hydrogen gas [205]. Therefore, the HES pathways are modeled to have a rated discharge time of 2190 hours, equivalent to one season. Technical parameters for each of the HES and BES technology pathway considered here are presented in Table 10.

Table 10: Technical parameters for ES technology pathways.

BES Equipment	**Round-Trip Efficiency (MWh-in/MWh-out)**	**HES Equipment**	**Round-Trip Efficiency (MWh-in/MWh-out)**
ZnBr	65.0%	AEC/FC*	46.3%
Li-Ion	90.0%	SOEC/FC*	45.7%
Pb Acid	89.0%	PEMEC/FC*	42.4%
Na-S	75.0%		

*The round-trip efficiency of the HES technology pathways are primarily dependent on the electrolyzer therefore there is no differentiation in efficiency between the different FC equipment types.

5.1.2 Renewable Gas Production

The renewable gas end-use scenario is composed of renewable hydrogen (R-H_2) and renewable methane (R-CH_4) production pathways. Renewable gas is produced to offset burning natural gas, such as for heating or industrial processes. The use of renewable gas for use as transportation fuel is considered in the transportation fuel end use case. Renewable gas was assumed to be transported via injection into the natural gas pipeline at either the distribution or

transmission pipelines. The technical parameters for the electrolyzers and methanator used in this end-use scenario are described in Table 11. The R-CH_4 technology pathway technical parameters are a combination of the electrolyzer and methanator equipment while the R-H_2 technology pathways only require the electrolyzer.

Table 11: Technical parameters for renewable gas technology pathways.

Electrolyzer Equipment	**H_2 Production (kWh/kg H_2)**	**Methanator Equipment**	**CH_4 Production (kg H_2/MMBtu CH_4)**
AEC	46.0	Methanator	9.6
SOEC*	35.1		
PEMEC	50.2		

*SOEC has are assumed to take in excess heat from power plants to reduce the electricity required to produce hydrogen.

5.1.3 Renewable Transportation Fuel Production for Zero Emission Vehicles

The renewable transportation end-use considered in this study considers renewable hydrogen production for FCEVs and renewable electricity charging for BEVs. The available excess renewable generation sets the maximum amount of renewable transportation fuel that can be produced, and therefore the maximum VMT that can be met using renewable hydrogen or electricity. FCEVs and BEVs also depend on different methods to uptake renewable electricity: the former relies on dispatching electrolysis loads which produce and store fuel, while the latter relies on dispatch of vehicle charging loads within travel constraints to coincide with renewable

generation. FCEVs and BEVs are further differentiated by the profile of their electric loads and their well-to-wheels efficiency. In general, BEVs can meet a higher amount of VMT due to higher efficiencies compared to FCEVs for the same amount of energy input [154].

Hydrogen for FCEVs requires additional electricity for compression to 700 bar in addition to the production of hydrogen from electrolyzers. The amount of compression is dependent on the transportation of hydrogen from electrolyzer to fueling station. The hydrogen can be produced offsite and transported in gaseous or liquid form or produced onsite in gaseous form. The technical parameters are a combination of the electrolyzer equipment in Table 11 and the distribution methods described in Table 12.

Table 12: Technical parameters for FCEV distribution methods.

H_2 Distribution Method	**H_2 Compression (kWh/kg)**
Gaseous Offsite	4
Liquid Offsite	15
Gaseous Onsite	70

Fueling for BEVs can be accomplished via three different charging scenarios: immediate, smart, and V2G. In summary, immediate charging produces electric loads based on charging BEVs immediately upon plug-in until the vehicle is fully charged or unplugged and does not have any communication with the electric grid. Smart charging will at best attempt to coordinate charging with low net load while ensuring enough charge to meet travel demand. V2G charging allows

BEVs to both charge vehicles during times of low net load and discharge electricity to the grid during times of high net load, while ensuring enough charge to meet travel demand. For each charging scenario three different charging power levels were considered: level III, 50 kW; level II, 6.6 kW; and level I, 1.44 kW.

5.2 Description of Electric Grid Modeling

The HiGRID model is used for the analysis in Task 2. The main sub-modules pertinent to this study are the ES sub-module, hydrogen electrolysis dispatch sub-module, and the BEV sub-module. These three sub-modules operate to modify the magnitude and temporal profile of the input electric grid net load demand. The sum of their effects produces a final net load demand profile, which represents the remaining electric load that must be satisfied by electricity generation from balancing power plants.

The HiGRID model is limited to hourly resolution and does not analyze more finely-resolved electricity production and demand in a highly renewable electric grid. The location of the electric vehicle chargers and hydrogen fueling stations were also not considered, such as the study by Stephens-Romero, Brown, and Kang (2010) [266] for siting of FCEV fueling stations and the study by Jia, Hu, and Song (2012) [267] for optimal siting and sizing of BEV charging stations. Future studies may require higher resolution operation and identifying the locations of stations if the technology pathways are mixed within an energy system. However, this study considers one single technology pathway at a time implemented in the California energy system and each technology pathway is subjected to the same limitations and evenly compared to all others.

HiGRID requires demand profiles to determine the dispatchable load for renewable gas and transportation fuel production; the demand profiles are based on the profile of otherwise curtailed electricity and light duty travel, respectively. These demand profiles are scaled to minimize otherwise curtailed electricity. An optimization of the demand profiles was not considered, in other words the amount of produced renewable gas or hydrogen was an input variable into HiGRID. The only outputs of HiGRID were the LCOE of each technology pathway and the entire energy system CO_2 emissions, LCOE, and RPS achieved. The profiles for each technology pathway were scaled similarly to capture the excess renewable electricity and therefore are congruent with the scope of this study. Future studies will consider the optimization of demand profiles for each technology pathway.

5.3 Description of Economic Analysis and Assumptions

The LCOE for each end-use technology pathway is calculated based on the methodology in the CEC Cost of Generation Module and is calculated within HiGRID in the Cost Module [268], [250], [269]. The input fuel cost for the end-use technologies is assumed to be zero since all fuel input is assumed to be excess renewable energy. The economic input parameters for each technology pathway can be found in APPENDIX C Task 2 Technology Parameters, compiled from sources such as the U.S. Department of Energy (DOE) [270], [254], [271], [272], [273], [274], [275], [276], [277], [278], [279], [263], [280], [281], [282], [283]. Each technology pathway is numbered from 1 to 46 in the economic values table; these numbers can be used to distinguish between the different technology pathways per end use.

The economic parameters for renewable hydrogen pathways are dependent on the electrolyzer technology. The economics for the renewable methane pathways are an aggregation of the electrolyzer technology with an attached methanator. The additional cost of the methanator for the renewable methane pathways is based on adding a percentage of the electrolyzer cost, based on a study by Budney [270]. The transmission pipeline pathways have an extra instant cost for additional compression compared to the distribution system pathways [263]. The HES pathways economic parameters are based on aggregation of electrolyzer and fuel cell economic parameters [271], [279], [263], [280]. The BES pathway economic parameters are based on DOE and EPRI vendor quotes [277]. The economic parameters for BEV pathways depend solely on charging power level, however the charging scenarios will change the operational characteristics which will affect the LCOE [281], [282].

Fueling for FCEVs consists of an electrolyzer to produce the hydrogen, followed by different methods of hydrogen transportation to the fueling station. The hydrogen can be produced centrally and trucked in either gaseous or liquid form or produced on-site in gaseous form. The economics underlying the LCOE calculations consist of an electrolyzer, transportation to the fueling station, and a fueling station. Fueling stations are assumed to have economic factors primarily based on an extra cost for transportation of fuel added separately on a per kilogram (kg) basis based on a study by NREL, as seen in Table 5 [283].

Table 5: Extra cost added to hydrogen pathways accounting for hydrogen fueling station costs.

Technology 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

5.4 Calculation of Levelized Cost of Energy and Greenhouse Gas Emissions

The main comparison metrics considered in this paper are system-wide change in LCOE to determine the cost effects of the excess renewable energy end uses and GHG emissions reductions. Note that the system-wide LCOE includes all energy forms utilized by the consumer – electricity and fuel, and energy content is assessed on a $/GJ basis. The system-wide LCOE is calculated, shown in Equation 20, by considering technology on the grid including electricity generation and the end-use technologies.

$$\text{LCOE}\left(\frac{\$}{\text{GJ}}\right) = \frac{\sum_{\text{All Technolgies}}\left(\text{Levelized Cost of Energy}\left(\frac{\$}{GJ}\right) * \text{Total Energy Produced (GJ)}\right)}{\sum_{\text{All Technologies}}\text{Total Energy Produced (GJ)}} \quad \text{Equation 20}$$

The GHG emissions are calculated within HiGRID by balancing the renewable capacity, electric demand, and dispatchable technologies. The GHG emissions are calculated considering all the technologies, the electric grid emissions, and the emission reductions of each pathway.

The ES end-use accounts for GHG emissions from only the electricity sector. The other end-uses replace carbon-based fuels in other sectors, thus reducing GHG emissions outside of the electricity sector. For example, the renewable transportation end-use replaces conventional gasoline vehicles, therefore the GHG emissions calculation includes the GHG emitted from the electric grid and the GHG reduction from replacing conventional vehicles which have an average emission factor of 411 g GHG/mile [284]. The reduction of GHG emissions for non-electricity sectors is calculated outside of HiGRID, as shown in Table 13.

Table 13: Calculated GHG offset values for non-electricity sectors.

End-Use	**GHG offset calculation factor**
Renewable Natural Gas	0.058 (ton GHG/MMBtu)
Renewable Transportation	411 (g GHG/mi)

To analyze the impacts of end-use strategies in a high RPS integrated electric grid, two base cases representing different amounts of installed renewables that does not include the implementation of any of the excess renewable generation end-use strategies is necessary as a point of reference. For comparison purposes, the renewable installed capacity was set to achieve a separate base case for an RPS of 70% and 80%, respectively. A breakdown of the different renewable generation sources is displayed in Table 14. This renewable capacity mix is used for the analysis of each end-use technology pathway's ability to capture and utilize excess renewable energy for the different end uses.

Table 14: Breakdown of capacity based on renewable resource.

RPS (%)	Total Renewable Capacity (GW)	Geothermal Capacity (GW)	Solar Capacity (GW)	Wind Capacity (GW)
70	132	5	99	28
80	220	9	165	46

Base case results for each RPS scenario can be seen in Table 15, which only includes results for the electric grid, prior to considering the impact of the transportation, heating, or industrial end-use strategies. There is a large amount of excess renewable energy available for the proposed end uses.

Table 15: The base case parameters and results of first-year California electric grid operation.

RPS (%)	GHG Emissions (Mt/yr)	Excess Renewable Energy (GW-yr)	LCOE ($/GJ)
70	29.21	72,870	64.87
80	12.68	211,189	100.93

To understand the effects of utilizing excess renewable energy, the focus of this study is on the GHG emissions reduction from the base case. Therefore, the results presented in the graphs are shown as the reduction from the base case. Calculations of GHG emissions reductions and LCOE reductions compared to the base case are shown in Equation 21 and Equation 22, respectively.

$$\mathrm{GHG}_{\mathrm{Reduction}} = \mathrm{GHG}_{\mathrm{Base\ Case}} - (\mathrm{GHG}_{\mathrm{Electric\ Grid}} - \mathrm{GHG}_{\mathrm{Offset}}) \quad \text{Equation 21}$$

$$\mathrm{LCOE}_{\mathrm{Change}} = \mathrm{LCOE}_{\mathrm{Base\ Case}} - \mathrm{LCOE}_{\mathrm{End\ Use}} \quad \text{Equation 22}$$

5.5 70% RPS Scenario

The results for GHG emissions reductions vs. reduction in LCOE for the 70% RPS scenario is displayed in Figure 21.

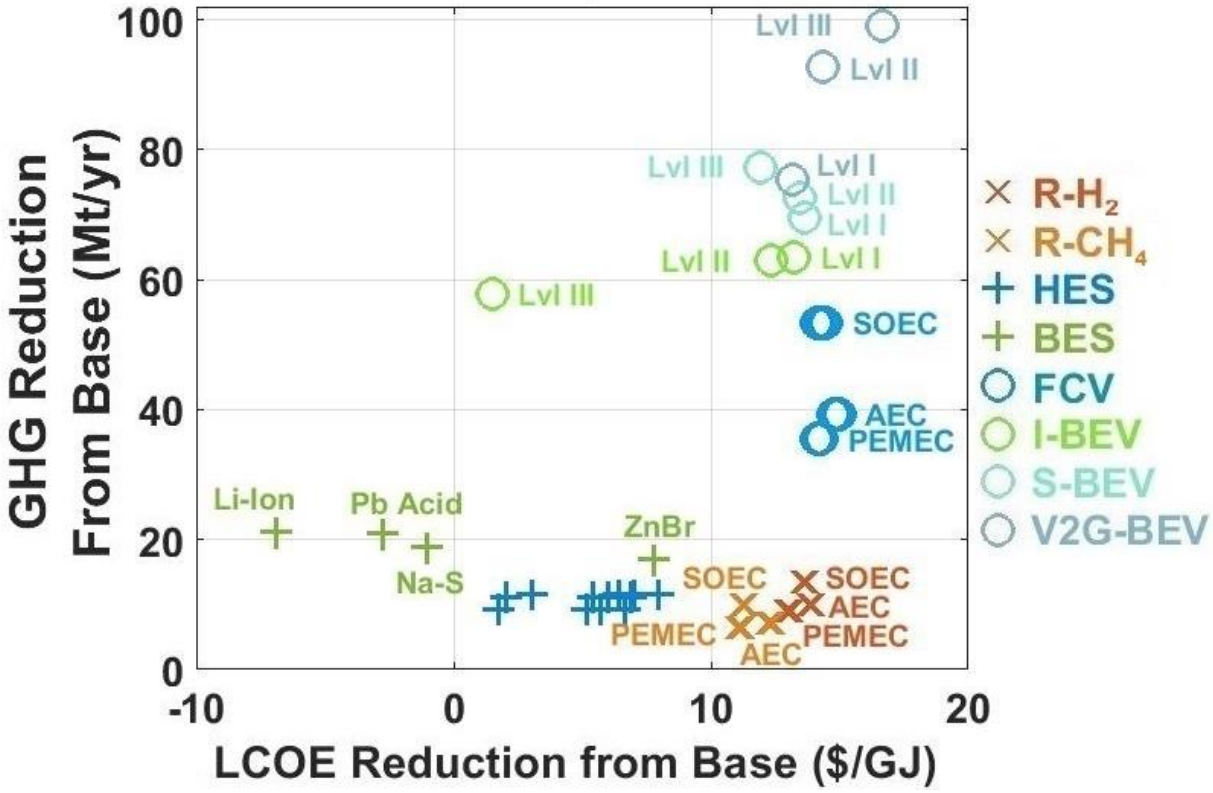

Figure 21: Graphical representation of GHG and LCOE reductions from the base case for the 70% RPS scenario. Legend: R-H_2 - Renewable Hydrogen End Use; R-CH_4 - Renewable Methane End Use; HES – Hydrogen Energy Storage End Use; BES – Battery Energy Storage End Use; FCEV – Fueling for FCEVs End Use; I-BEV –Immediate Charging for BEVs End Use; S-BEV –Smart Charging for BEVs End Use; V2G-BEV – V2G Charging for BEVs End Use.

5.5.1 Changes in Levelized Cost of Energy – 70% RPS

Most of the technology pathways result in a reduction of system wide LCOE from the base case for the 70% RPS scenario. This represents the economic advantage of utilizing rather than curtailing excess renewable energy. The highest reductions of LCOE are seen in the most flexible

technology pathways that can capture and utilize excess renewable energy such as the production of renewable gas, V2G-BEV charging, and FCEV fuel production. The Immediate-BEV Level III charging represents the least flexible pathway and does not provide as significant of an LCOE reduction benefit compared to other technology pathways. Flexibility refers to the technology pathway's ability to match electricity consumption to renewable electricity production, therefore utilizing otherwise curtailed electricity. The flexible technology pathways increase the amount of system-wide useful energy without requiring a significant increase in investment costs and therefore decrease the system-wide LCOE.

Despite having higher flexibility to utilize excess renewable energy than Immediate-BEV charging, three of the ES pathways show an increase in LCOE (Li-Ion, Pb Acid, and Na-S batteries) and in general ES technologies have low reductions of LCOE. This occurs since both BES and HES technologies have relatively high capital costs and displace cheaper but non-renewable power plants. Therefore, these cases increase the system-wide LCOE, as opposed to other end uses that do not offset fossil fuel-based electricity generation.

5.5.2 GHG Emissions Reduction – 70% RPS

GHG emissions reductions achieved by each technology pathway can vary depending on operational flexibility, fuel production efficiency, and the conventional fuel being replaced. The renewable hydrogen, renewable methane, and ES pathways have low GHG emissions reductions since these end uses offset natural gas which has a relatively low carbon intensity. For example, the technology being replaced by the ES pathways are natural gas combined cycles and the technology being replaced by the renewable hydrogen and renewable methane pathways are

direct natural gas combustion. These technology pathways replace lower carbon intensities compared to transportation pathways that replace gasoline. Renewable hydrogen and renewable methane pathways have slightly lower GHG emissions reductions than other pathways due to having a constant electric demand for compression and transportation of gas through the pipeline system that is unable to match with excess renewable electricity generation. Also, only ES pathways result in a reduction of electric grid GHG emissions. ES pathways primarily result in emissions reductions by displacing fossil-fuel electricity generation on the grid. All other pathways primarily provide GHG emissions reduction by offsetting fuel use in sectors outside of the electric grid, seen in Equation 21.

The renewable transportation pathways display the highest GHG emissions reductions due to replacing gasoline which is a large GHG emissions source. GHG emissions reduction for FCEVs is dependent on the efficiency of the electrolyzer, which when ordered from highest to lowest efficiency, are SOEC, AEC, and PEMEC. This parallels the same order for highest to lowest GHG emissions reductions. This trend is also true for the HES pathways (although the electrolyzers are not explicitly labeled in Figure 21). Using excess renewable energy to charge BEVs provides higher GHG emissions reductions compared to using it to produce hydrogen fuel for FCEVs. This is due to the higher efficiency of charging BEVs compared to fueling FCEVs when starting with electricity as an input. Therefore, a fixed amount of excess renewable energy will provide more renewably fueled vehicle miles traveled when used in BEVs compared to use in FCEVs when both pathways are able to capture all the available excess renewable generation.

For BEVs, however, the ability to capture excess renewable generation depends on charging flexibility. Implementing flexible charging capabilities such as smart or V2G charging allows matching the timing of charging loads to excess renewable generation that results in higher reductions of GHG emissions and further improves with higher charging capacities. By contrast, immediate BEV charging, which is inherently inflexible, had relatively limited GHG emissions reductions and worsened in GHG reduction performance with increased charging capacities. For immediate charging, Level I charging had a higher GHG reduction than Level III; this is due to Level III charging adding sudden large loads to the electric grid during times with minimal excess renewable generation, which required additional ramping and generation from conventional fossil fuel-fired power plants. Despite an overall reduction of GHG emissions, the GHG emissions for the BEV immediate charging scenarios shifted emissions to the electric grid due to inability to match charging with renewable electricity generation.

5.5.3 Investment Cost of GHG Emissions Reductions – 70% RPS

While implementing most of the technologies considered here to capture excess renewable generation for useful purposes provides reductions in LCOE due to the economic benefit of not wasting renewable generation outweighing investment costs on a system-wide basis, capital funds must still be provided up-front and operating costs must still be shouldered by investing entities to obtain those benefits. Additionally, system-wide cost reductions are not necessarily transferred in full to the entities providing the initial investment for the installation of these technologies or bearing the ongoing cost of operating them. It is therefore important to characterize the investment costs needed to install and operate the technologies needed for

reducing GHG emissions. The semi-log bar graph for the per tonne investment cost of GHG emissions reduction for each pathway is displayed in Figure 22.

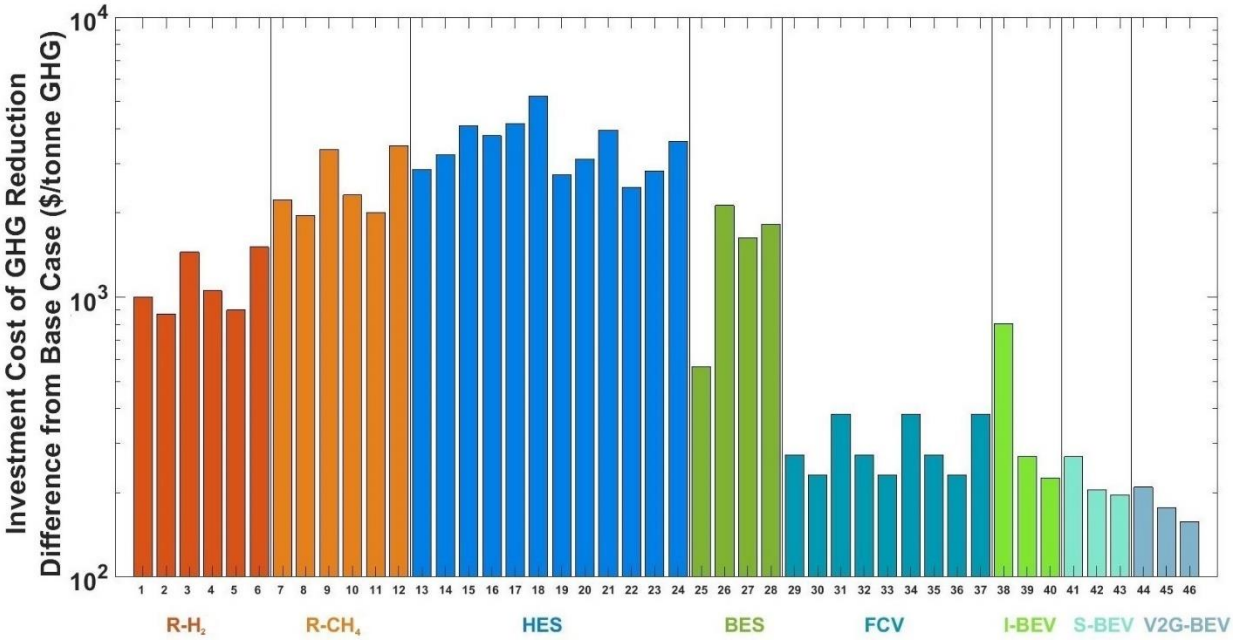

Figure 22: A semi-log bar graph of per tonne investment cost of GHG emissions reduction for each pathway considered in this study for a base case of 70% RPS scenario. The numbers underneath each pathway can be correlated to the technology pathways listed in APPENDIX C Task 2 Technology Parameters. The notations of end-uses are consistent with Figure 21.

The ES pathways have the highest per tonne investment cost of GHG emissions reductions and the renewable transportation pathways have the lowest, which follows the trend of GHG emissions reductions shown in Figure 21. However, Level III immediate BEV charging had the highest cost of GHG emissions reductions out of all transportation pathways due to the inability to utilize excess renewable energy and therefore resulting in high operating costs, combined with high capital costs for installing high capacity chargers. Overall, only the renewable transportation end-use pathways are on par with the lower-end results produced by Sims, Rogner, and Gregory

(2003) [231] for cost of GHG emissions reductions by replacing new coal or natural gas power plants with renewable technologies, approximately $200/tonne GHG reduced, and less than the $600/tonne GHG reduced with solar from the study by Marcantonini and Ellerman (2013) [233]. The BES and renewable hydrogen pathways are on par with the high-end results from the study by Sims, Rogner, and Gregory (2003) [231], approximately $2,000/tonne GHG reduced. The HES and renewable methane pathways have higher costs for GHG emissions reduced than all other pathways and other studies. This outlines the importance of replacing heavier hydrocarbon energy sources with renewable hydrogen-based energy sources to achieve both the highest and cheapest GHG emissions reductions.

These results indicate that to spur investment into technologies needed to utilize excess renewable generation for useful purposes, values equivalent to these costs per tonne of GHG emissions reduction must be garnered by the entities that invest and operate these technologies.

5.6 80% RPS Scenario

The results for the GHG emissions reductions vs. change in LCOE for the 80% RPS scenario are displayed in Figure 23.

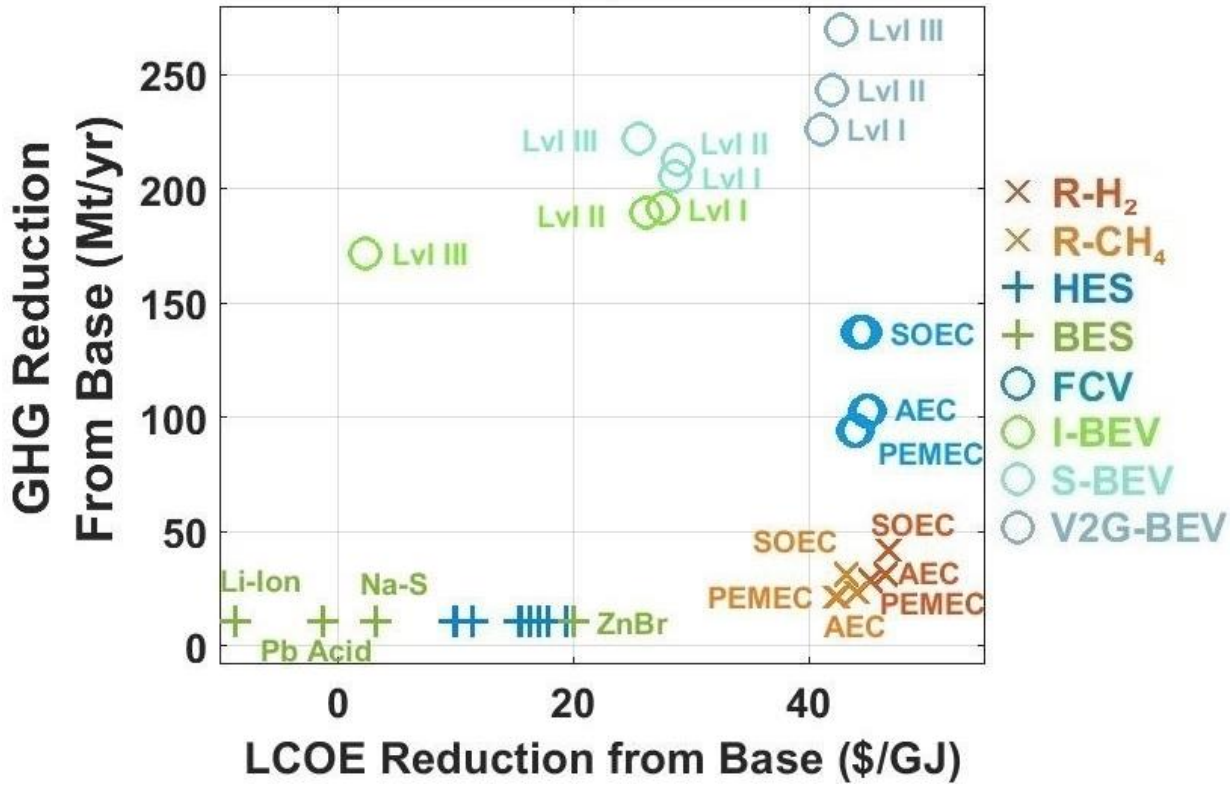

Figure 23: Graphical representation of GHG and LCOE reductions from the base case for the 80% RPS scenario. The notations of end uses are consistent with Figure 21.

Compared to the 70% RPS scenario, the 80% RPS scenario has higher LCOE and GHG emissions reductions from its base case. This is due to the 80% RPS scenario having higher renewable capacity on the electric grid and approximately three times the amount of excess renewable energy compared to the 70% RPS scenario. The overall trends convey similar results to the 70% RPS scenario. The flexibility of technology pathways to align electric loads with excess renewable generation, as well as the carbon intensity of the technologies being replaced, contributed to GHG emissions and LCOE reductions. For example, the renewable transportation and renewable gas pathways are flexible and can utilize the otherwise curtailed energy and therefore result in high GHG emissions and LCOE reductions.

The disparities of LCOE reduction also become more apparent at higher RPS. Since its base case renewable installed capacity is high and there is a large amount of curtailed energy, the technologies that can utilize the greatest amount of otherwise curtailed energy are thus also able to reduce the LCOE by the greatest margin. The highest LCOE reductions are the renewable gas and flexible renewable transportation pathways: V2G charging for BEVs and all of FCEV pathways that use dispatchable electrolysis. The other pathways are restricted by operational constraints. Immediate and smart charging for BEVs must meet the demand for charging that are not flexible enough to completely match charging loads with otherwise curtailed energy.

The apparent limitations of ES pathways to reduce GHG emissions are also more visible in the 80% RPS scenario. ES pathways contribute to reduction of GHG emissions on the electric grid only and do not contribute to GHG emissions reductions in other sectors. In the 80% RPS scenario, however, most of the electric load is already satisfied by renewable generation and only a small amount of carbon-emitting generation is still present, which sets the limit by which GHG emissions can be reduced by ES pathways. Figure 23 shows the same GHG emissions reductions across all ES pathways. This shows that while ES can improve the GHG emissions performance of the electric grid, it is the least effective and most limited end use for large-scale utilization of excess renewable energy for overall GHG emissions reduction at high RPS.

The immediate BEV charging pathways are unable to match charging with available renewable generation and result in a significant increase in GHG emissions in the electric grid, but due to an even greater magnitude of decreases in transportation sector emissions still provides an overall decrease in GHG emissions. This shows that regardless of the negative effects

to the electric grid, replacing higher GHG emitting technologies has an overall beneficial effect on GHG emissions reduction. Therefore, the best pathways to reduce the largest amount of GHG emissions are centered on the high GHG emitting, gasoline-dependent transportation sector.

5.6.1 Investment Cost of GHG Emissions Reductions – 80% RPS

The investment cost of reducing GHG emissions for the 80% RPS scenario increases for the ES pathways and decreases for the renewable gas and transportation pathways as compared to the 70% RPS scenario, as seen in Figure 24.

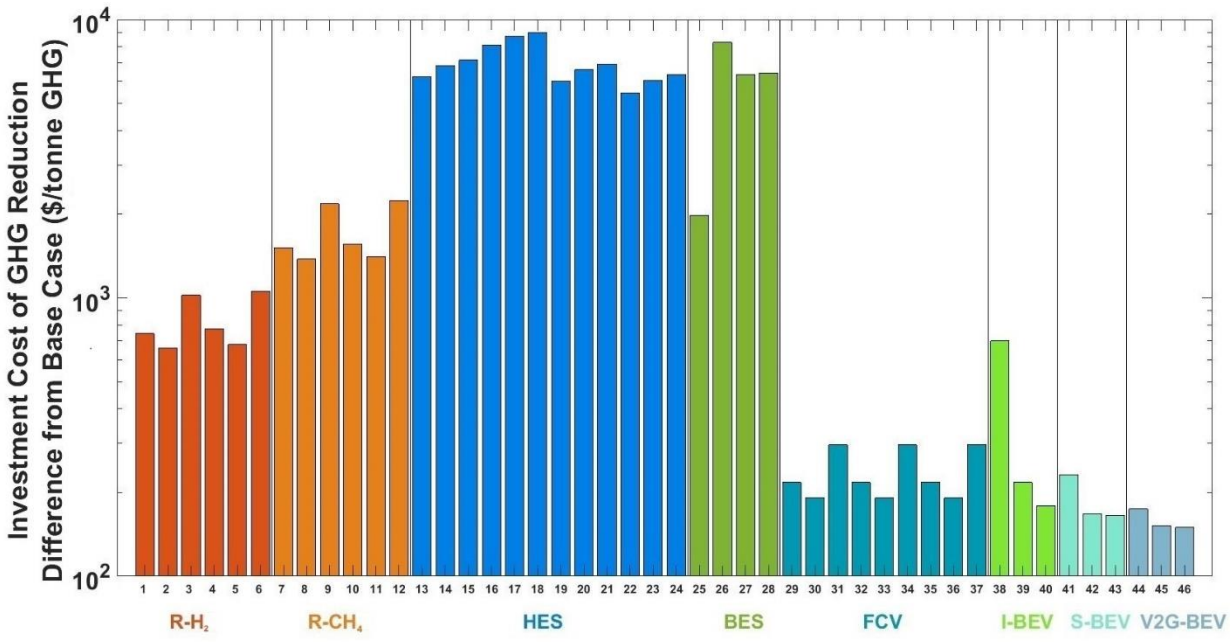

Figure 24: A semi-log bar graph of per tonne investment cost of GHG emissions reduction for each pathway considered in this study for a base case of 80% RPS. The numbers and notations of end uses are consistent with Figure 22.

The investment cost of GHG emissions reductions for the ES pathways increases for the 80% RPS scenario compared to the 70% RPS scenario, due to the limitations of reducing GHG

emissions from the electric grid at high RPS. The investment costs of GHG emissions reductions for the renewable gas and transportation pathways decrease as there is a higher availability of excess renewable energy to replace conventional GHG emitting technologies such as burning natural gas or gasoline.

6 TASK 3 – Develop an optimization model which utilizes excess renewable electricity for different end-use systems

To better understand the future electric system, an optimization model was developed to compare and consider a variety of end-uses and sectors as opposed to the previous analysis. The following analysis has portions that are undergoing submission and may be published in a journal.

In summary, this study leverages the HiGRID tool in combination with a technology-selecting optimization approach to determine the lowest-cost portfolio of technologies that can capture ERE for useful purposes based on their costs and temporal flexibility. This task focuses on the years 2030 to 2045, which correspond to California's goals for a 60% RPS and a 100% zero-carbon electricity system, respectively. The optimization model takes the load profiles from HiGRID to determine which technologies are utilized to meet the RPS goals. Finally, the results are used to calculate system-wide costs, which is primary comparison between the different scenarios.

An overview of the methodology is described in Figure 25.

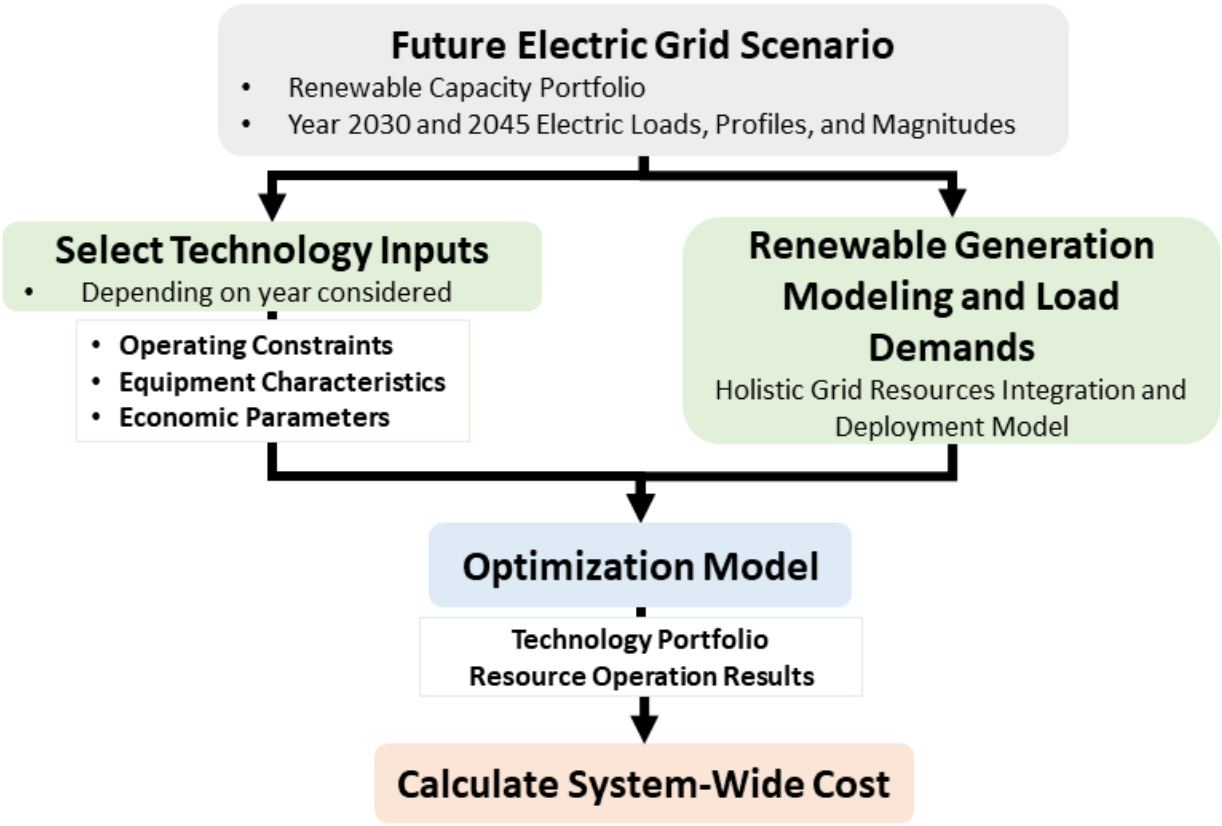

Figure 25: An overview of the study methodology.

For this study, we consider a range of ES technologies for capturing and managing ERE, classified into two categories: closed-form and produced-gas energy storage.

Closed-form energy storage refers to an ES system where the equipment that charges the storage system is strictly coupled with the equipment that discharges the storage system. For example, for pumped hydropower energy storage, energy stored by pumping water up to a reservoir, can only be discharged by release of the stored water through a liquid turbine. A similar principle applies for batteries: the same physical subsystems are responsible for both charging and discharging, with the latter operating them in reverse compared to the former. The types of

closed-form energy storage considered here are summarized in Table 16, with inputs for costs and operating characteristics specified in APPENDIX C Task 2 Technology Parameters.

Table 16: Closed-form energy storage types considered in this study

Type	**Subtypes**
Battery Energy Storage (BES)	Lithium-ion (Li-Ion) Zinc-Bromide Flow Battery (ZnBr)
Pumped Hydropower (PHES)	N/A
Compressed Air Energy Storage (CAES)	N/A

Produced gas energy storage refers to an energy storage system that depends on producing a gas such as hydrogen or renewable natural gas from excess wind and solar generation. These storage systems differ from closed-form energy storage in that the equipment that produces the gas (i.e., that charges the storage) can be selected and sized separately from the equipment that converts the stored gas back into electricity (discharges the storage). For example, charging the storage can occur using different types of electrolyzers each with different costs and operating characteristics. Once the gas is produced, it can be converted back to electricity via different power generation equipment: different types of fuel cells for hydrogen or natural gas, or even gas turbines. The selection and size of the charging equipment is decoupled from the selection of discharging equipment. The equipment types for produced-gas energy storage considered in this study are summarized in Table 17 with inputs for costs and operating characteristics specified in the APPENDIX C.

Table 17: Produced gas energy storage equipment subsystems considered in this study

Produced Gas Equipment Subsystems	**Subtypes**
Charging Subsystem Options:	Electrolyzers (ELY) – H2 production Alkaline (AEC) Solid Oxide (SOEC) Proton Exchange Membrane (PEMEC) Methanator Can be added to any of the electrolyzer types to produce renewable natural gas instead of hydrogen
Storage Subsystem Options:	Underground Natural Gas Pipeline Above Ground Storage Tanks
Discharging Subsystem Options:	Fuel Cells Phosphoric Acid (PAFC) Solid Oxide (SOFC) Proton Exchange Membrane (PEMFC) Molten Carbonate (MCFC)

6.1 Description of Integration with HiGRID

For this study, HiGRID determines the generation profiles of renewable (solar, wind, geothermal) and zero-carbon (hydropower) sources. The Renewable Generation Module

determines an hourly-resolved profile for renewable generation for solar PV, onshore wind, and small hydropower. The net load is then calculated with the renewable and dispatchable generation profiles determined from HiGRID to determine the electric demand that still needs to be balanced and the amount of ERE. The ERE profile is then used to determine the renewable electricity that is available for use in electrolyzers, ES, and ZEVs.

6.2 Description of Optimization Model

The optimization model determines which technologies are chosen to capture the ERE and how each is dispatched in time, with hourly resolution, to meet the net electricity load (encompassing residential, commercial, industrial, electrified fuel production, and electrified transportation loads). An overview of the optimization is detailed in Figure 26. The technology costs, operating constraints, and efficiencies are based on a variety of sources, detailed in APPENDIX C. The FCEV fueling profile is based on the operation of a Chevron gasoline pump station, as FCEV hydrogen fueling stations operate similarly to a gasoline pump station [255]. The ERE generation, electricity demand, and vehicles charging profiles are a combination of HiGRID output and E3 PATHWAYS study assumptions. The cost of renewable electricity is based on the total renewable generation determined from HiGRID. The order of model use is presented in Figure 27. This shows how HiGRID is integrated with E3 PATHWAYS inputs to help determine the inputs to the optimization. The constraints and objective function equations are thus translated in YALMIP to initialize the optimization in CPLEX. The outputs are analyzed within HiGRID again to save the data, plot graphs, and other data analytics. A more detailed flow of the optimization Matlab script can be found in APPENDIX D.

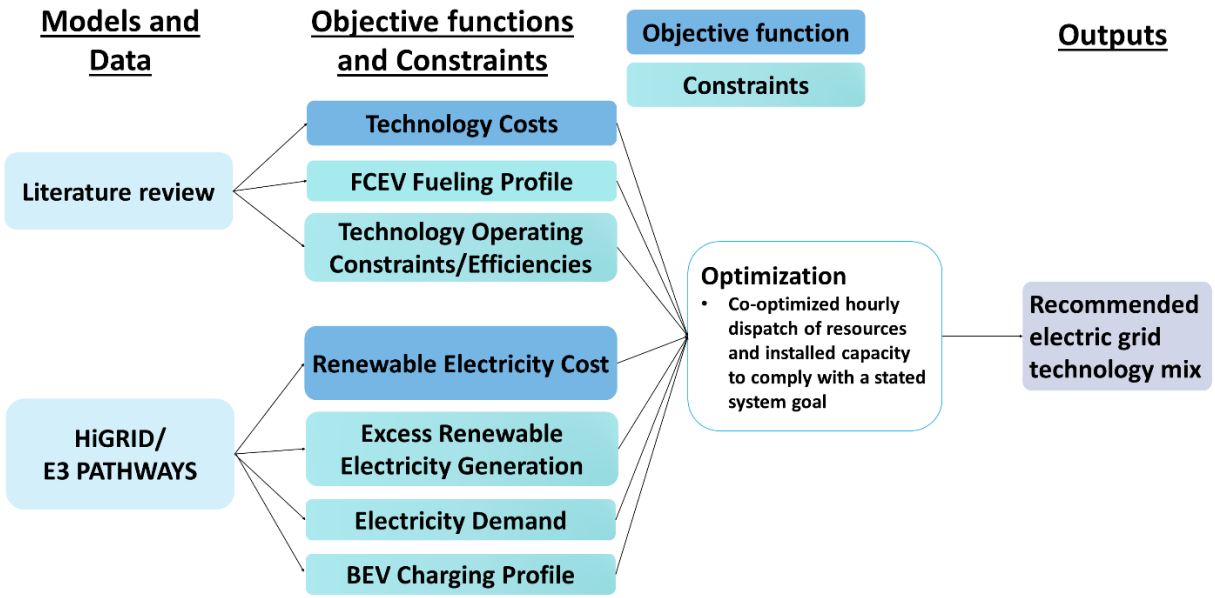

Figure 26: An overview of the study methodology.

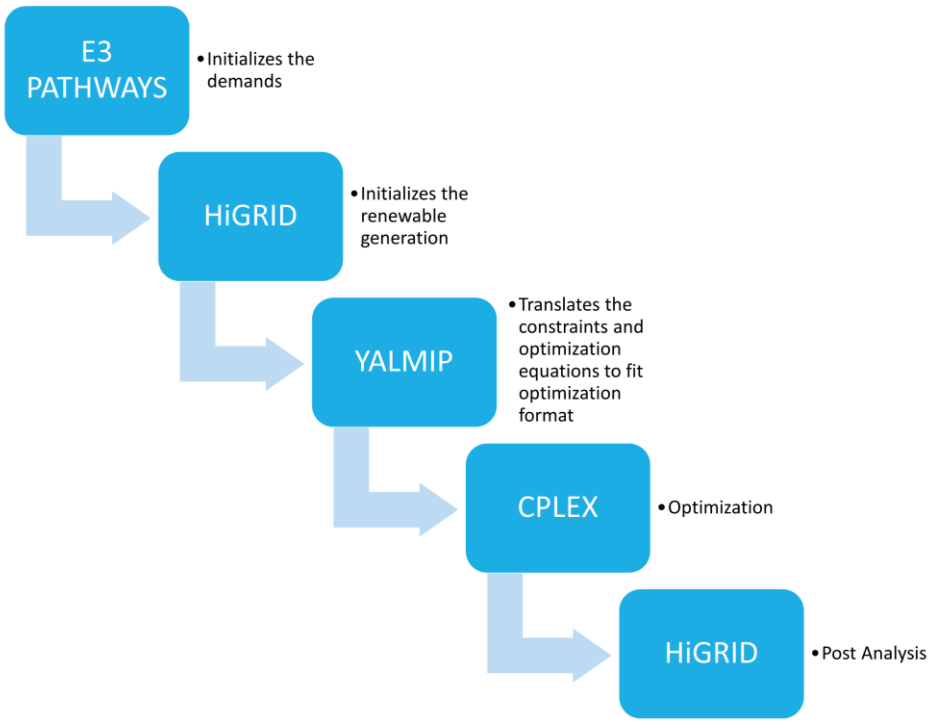

Figure 27: The order of modeling use and a short description of the model use for this analysis.

This optimization determines the hourly dispatch of the selected technology types by balancing the electricity flows and produced gas.

Hydrogen

Electrolyzers are assumed to use only ERE to produce hydrogen in this study. The produced hydrogen can be used for fueling in a FCEV, as energy storage for ultimate use in a stationary FC for power-to-gas-to-power (P2G2P), or injected directly into the NG pipeline as pure hydrogen or renewable methane. Pure hydrogen cannot exceed 20% by volume for natural gas power plants, to maintain acceptable hydrogen mixtures [257]. The hydrogen energy storage (HES) system is set to have the same amount of hydrogen at the start and end of the year to capture end of year characteristics.

Natural Gas/Renewable Gas

The natural gas system provide gas for the natural gas power plants as well as non-electric demands. The natural gas system can utilize either fossil fuel natural gas or renewable gas, mixture of hydrogen and methane. The hydrogen is produced from the electrolyzer and the methane is produced using the produced hydrogen in a methanator with CO_2. The mixture of hydrogen to methane, on an annual basis, must be less than 20% by volume. There are also hourly limitations of total natural gas system for the percent of hydrogen.

Electricity

Determined from HiGRID, the dispatchable electric demand (D_{Disp}) is the portion of total electric demand (D_{Total}) that cannot be met directly with renewables (RE_{Direct}) as seen in

Equation 1. This represents the net electric load profile that the portfolio of energy storage technologies selected by the optimization must meet.

$$D_{Disp} = D_{Total} - RE_{Direct} \quad \text{Equation 23}$$

Also determined from HiGRID, the amount of ERE (ERE) is the portion of renewable generation (RE_{Total}) that cannot be used to directly meet the total electric demand, as seen in Equation 2.

$$ERE = RE_{Total} - RE_{Direct} \quad \text{Equation 24}$$

Electricity from ERE is either stored for later dispatch or curtailed, whichever meets the zero-carbon policy goal at lowest cost for the given installed renewable capacity. Similar to HES, the closed-form ES systems to balance generation and dispatch is set to have the same amount of stored energy at the start and end of the year to capture end of year characteristics.

6.2.1 Variables

The optimization model determines both the installed capacity and the hourly dispatch operation of the ES technologies. Produced gas ES options can have multiple technology subtypes. Each technology, generally noted as $_{tech}$, is denoted individually in the optimization equations, with the equipment types for each technology represented by subscript k. For example, ELY_k represents all the electrolyzers: AEC, SOEC, PEMEC. Technologies which can use both directly captured and stored renewable electricity are split into two vectors, denoted by ren or $nonren$

respectively. The BES technology is also split into charging and discharging, denoted as ch or dch respectively.

The hourly dispatch is denoted with $P_{tech_k,t}$ with t spanning from 1 to 8760 which represents the hours in a year. The capacity is denoted with $P_{tech_k}^{cap}$.

6.2.2 Constraints

Capacity Constraints

Each technology and equipment type has its hourly dispatch constrained by its installed capacity and must be non-negative, as seen in Equation 25.

$$P_{tech_k,t} \leq P_{tech_k}^{cap}$$
$$P_{tech_k,t} \geq 0 \qquad \text{Equation 25}$$

Some technologies also have a minimum constraint greater than 0, such as the maximum depth of discharge for Li-Ion BES or the minimum cushion gas required for HES. These constraints, represented as $Minimum_{\%}$, would therefore be dependent on the capacity as in Equation 26. The numerical values of these constraints are listed in the following sections.

$$P_{tech_k,t} \geq Minimum_{\%} * P_{tech_k}^{cap} \qquad \text{Equation 26}$$

There are also some maximums that are based on a numerical value, independent of the capacity. These constraints would be represented as seen in Equation 27. For example, pumped hydro has a maximum energy capacity and underground HES has a maximum storage capacity.

$$P_{tech_k,t} \leq Maximum \qquad \text{Equation 27}$$

Electricity Energy Balance

ERE, denoted as $P_{ERE,t}$ (ERE), is used to directly provide renewable electricity to electrolyzers ($P_{ELY_k,t}$), to run hydrogen fueling stations associated with meeting the FCEV demand ($P_{H2statren,t}$), to charging BEVs ($P_{BEVren,t}$), to Electrical Furnaces (EF) for meeting the heat requirements of certain electrolyzers and fuel cells ($P_{EFren,t}$), and to ES ($P_{ESch_k,t}$) or is curtailed ($P_{CURT,t}$). The hydrogen produced is represented through the electrolyzers which produce hydrogen for both FCEVs and FCs. The electrical furnace is used to ensure thermal stability for solid oxide fuel cells, solid oxide electrolyzers, and molten carbonate fuel cells, with the thermal heat requirement calculation detailed later in this section. The use of ERE at each hour t is described in Equation 28.

$$\sum_k P_{ELY_{ren_k},t} + P_{H2stat_{ren},t} + P_{BEV_{ren},t} + \sum_k P_{ES_{rench_k},t} + P_{EF_{ren},t} + P_{CURT,t} = P_{ERE,t} \qquad \text{Equation 28}$$

The electricity demand that cannot be directly met with renewable electricity is met using stored ERE as described in Equation 29 with energy storage ($P_{ESdch_k,t}$) or fuel cells ($P_{FCdch_k,t}$) or natural gas powerplants, $P_{FCdch_k,t}$ in cases where renewables are unable to meet all the demand such as in years earlier than 2045.The temporal profile of the dispatchable net electric load to be met is denoted as $D_{Disp,t}$. There are also electric demands for BEVs, denoted as $P_{BEV_nonren,t}$, hydrogen fueling stations denoted as $P_{H2stat_nonren,t}$, non-renewable charging for ES ($P_{ES_nonrench_k,t}$) and hydrogen production in electrolyzers ($P_{ELY_nonren_k,t}$), and for and electrical furnaces, denoted as $P_{EF_nonren,t}$. There is also a constraint on the RPS ($\%_{RPS}$) which is based on a mix of variables and inputs, seen in Equation 30. The inputs come from the total renewable generation ($P_{Ren,t}$) (which includes solar, wind, and geothermal) and since large hydropower is not considered renewable it is considered separately ($P_{Hydro,t}$). Note, this hydropower is considered flow of the river

hydropower generation and is not associated with pumped hydro energy storage. The variables are based on the operation of non-renewable fossil fuel natural gas power plants ($P_{NG,t}^{NGPP}$) and the amount of curtailed electricity ($P_{CURT,t}$). The reverse of RPS is used, in other words the optimization considers the non-renewable percentage or 1-$\%_{RPS}$. The purpose of using the reverse of RPS is to reduce the number of variables used.

$$\sum_{k} P_{ESdch_k,t} + \sum_{k} P_{NGPP_k,t} + \sum_{k} P_{FCdch_k,t} = D_{Disp,t} + P_{BEV_{nonren},t} + P_{H2stat_{nonren},t} + P_{EF_{nonren},t} + \sum_{k} P_{ELY_{nonren_k},t} + \sum_{k} P_{ES_{nonrench_k},t} \quad \text{Equation 29}$$

$$\sum_{t=1}^{8760} \left(\sum_{k} P_{NG,t}^{NGPP_k} + P_{Hydro,t} \right) = (1 - \%_{RPS}) \sum_{t=1}^{8760} \left(\sum_{k} P_{NG,t}^{NGPP_k} + P_{Hydro,t} + P_{Ren,t} - P_{CURT,t} \right) \quad \text{Equation 30}$$

Although not pertaining to electricity, there is also a constraint on the balance between SMR ($P_{SMR,t}$) and electrolytic production of hydrogen ($P_{ELY_k,t}$) based on the percent allowable of SMR, similar to the RPS constraint, seen in Equation 31.

$$\sum_{t=1}^{8760} P_{SMR,t} = \%_{SMR} \sum_{t=1}^{8760} (P_{FCEV,t}) \quad \text{Equation 31}$$

Energy Storage Balance

The ES is balanced so that the energy stored at the beginning of the year at t=0, $P_{ES_k,b}$, is the same as at the end of the year (t=8760), as detailed in Equation 32. The amount of energy stored for each technology is represented as $P_{ESst_k,t}$. The amount of stored energy is also constrained depending on the number of hours each technology can hold, represented in Equation 32. The beginning and end of year constraint is also applied to HES.

$$\begin{cases} t = 1 & P_{ES_k,b} + P_{ESch_k,t} - P_{ESdch_k,t} = P_{ESst_k,t} \\ 1 < t < 8759 & P_{ES_k,t-1} + P_{ESch_k,t} - P_{ESdch_k,t} = P_{ES_k,t} \\ t = 8760 & P_{ES_k,t-1} + P_{ESch_k,t} - P_{ESdch_k,t} = P_{ES_k,b} \end{cases}$$ Equation 32

Table 18: Capacity constraints for closed-form energy storage.

Technology types	**Constraint**	**References**
Li-Ion BES	4 hours at maximum discharge and 77% maximum depth of discharge	[285], [286]
ZnBr BES	4 hours at maximum discharge	[285]
CAES	16 hours at maximum discharge and 30% minimum gas percent	[285], [287]
Hydro	15 hours at maximum discharge and 3967 MW maximum installed capacity	[102], [103]

Hydrogen is produced from electrolyzers ($P_{SMR,t}$) and can also be produced from other means such as SMR ($P_{SMR,t}$), the SMR variable can be any form of non-electric hydrogen production but for the purpose of variable definitions SMR is used. Hydrogen is used for FCEVs ($P_{FCEV,t}$) and stationary FCs ($P_{FC_k,t}$) and can be injected into the natural gas pipeline system ($P_{renNG_k,t}$), as seen in Equation 33. The hydrogen demand for FCEVs and FCs have the same annual energy content as the electric demand of FCEVs and the electricity production for FCs, respectively, with an efficiency factor difference between hydrogen and electricity. These factors can be found in the APPENDIX C.

The stored hydrogen is also balanced such that the amount stored at the beginning of the year, $P_{HES_k,b}$, matches with the amount stored at the end of the year at t equal to 8760 hours, with the hydrogen stored between the beginning and end of the year represented as $P_{HES_k,t}$ The sum

of the technologies is taken since the storage is independent from the technologies which produce or consume the hydrogen. The amount of energy stored is independent of the production or the usage due to being stored in a separate HES system. The constraints of HES can be found in Table 19.

$$\begin{cases} t = 1 \\ 1 < t < 8759 \\ t = 8760 \end{cases} \begin{matrix} \sum_k P_{HES_k,b} + P_{SMR,t} + \sum_k P_{ELY_{nonren_k},t} + \sum_k P_{ELY_{ren_k},t} - \sum_k P_{FCEV,t} - \sum_k P_{FC_k,t} - \sum_k P_{renNG_k,t} = \sum_k P_{HES_k,t} \\ \sum_k P_{HESbe_k,t-1} + P_{SMR,t} + \sum_k P_{ELY_{nonren_k},t} + \sum_k P_{ELY_{ren_k},t} - \sum_k P_{FCEV,t} - \sum_k P_{FC_k,t} - \sum_k P_{renNG_k,t} = \sum_k P_{HES_k,t} \\ \sum_k P_{HESbe_k,t-1} + P_{SMR,t} + \sum_k P_{ELY_{nonren_k},t} + \sum_k P_{ELY_{ren_k},t} - \sum_k P_{FCEV,t} - \sum_k P_{FC_k,t} - \sum_k P_{renNG_k,t} = \sum_k P_{HES_k,b} \end{matrix}$$ Equation 33

Table 19: Capacity constraints for hydrogen energy storage.

Technology types	**Constraint**	**References**
HES Underground	Maximum total volume of 9,891,014,832 m^3 with a minimum of 30% devoted to (unusable) cushion gas	[288], [287]
HES Above Ground Storage Tanks	Unlimited, determined as needed and constrained by cost.	

Natural Gas Balance

A constraint for natural gas is a percent volume of hydrogen, $vol\%_{H2}$, to ensure there is no risks utilizing the gas blend in end-use devices or safety, as seen in Equation 34 [136]. The variables are changed from $P_{tech_k,t}$ to $V_{tech_k,t}$ for volume of the gas, this is achieved using the lower heating value of each gas type, listed in Table 20 [289].

$$V_{H_2,t} \leq vol\%_{H2} * (V_{H_2,t} + V_{CH_4,t} + V_{NG,t}) \quad \text{Equation 34}$$

Table 20: The lower heating value of each gas.

Gas type	**Fossil Fuel Natural Gas**	**Methane**	**Hydrogen**
Lower Heating Value (Btu/ft^3)	983	964	290

The balance for the natural gas system is a combination of gas used for both non-electric (P^{NG}), such as residential, commercial, and industrial, and electric, such as natural gas power plants (P^{NGPP_k}), uses. The gas can either be fossil fuel natural gas ($P_{fNG,t}$) or renewable gas ($P_{renNG_j,t}$), renewable hydrogen ($P_{renNG_{H2},t}$) and/or renewable methane ($P_{renNG_{CH4},t}$). The assumption is to use the currently existing natural gas system, so no energy storage system costs are associated other than gas distribution costs. The constraints are based on the electric ($P_{NGPP_k,t}$), which is multiplied by an efficiency (η_k) to convert to fuel demand (the efficiencies can be found in the APPENDIX C), and non-electric gas demands ($D_{NG,t}$), as seen in Equation 35 to Equation 39. Equation 35 details the split of renewable gas for each sector and Equation 36 details the split of fossil fuel natural gas for each sector, the sectors being electric ($NGPP$) and non-electric (NG). Equation 37

shows that the hourly demand for each sector must be met by either renewable gas or fossil fuel natural gas. Equation 38 and Equation 39 show that annual amount of gas use for each sector individually is not time constrained. The purpose of this constraint is in the case of a zero-carbon electric grid, the gas use in natural gas power plants must be all renewable. However, the production of renewable gas may not fall in line with the generation of electricity from the natural gas power plants. By ensuring the total annual production of renewable gas equals the total annual use of natural gas power plants, time and storage of that renewable gas is not an issue and allows the renewable gas to take full advantage of storing gas in the natural gas system.

$$\sum_{j}\sum_{k} P_{renNG_{j,t}}^{NGPP_k} + \sum_{j} P_{renNG_{j,t}}^{NG} = P_{renNG_k,t} \quad \text{Equation 35}$$

$$\sum_{k} P_{fNG,t}^{NGPP_k} + P_{fNG,t}^{NG} = P_{fNG,t} \quad \text{Equation 36}$$

$$\sum_{k} P_{renNG_k,t} + P_{fNG,t} = \sum_{k} \eta_k * P_{NGPP_k,t} + D_{NG,t} \quad \text{Equation 37}$$

$$\sum_{t=1}^{8760}\left(\sum_{j}\sum_{k} P_{renNG_{j,t}}^{NGPP_k} + \sum_{k} P_{fNG,t}^{NGPP_k}\right) = \sum_{t=1}^{8760}\left(\sum_{k} \eta_k * P_{NGPP_k,t}\right) \quad \text{Equation 38}$$

$$\sum_{t=1}^{8760}\left(\sum_{j} P_{renNG_{j,t}}^{NG} + P_{fNG,t}^{NG}\right) = \sum_{t=1}^{8760} D_{NG,t} \quad \text{Equation 39}$$

Thermal Constraints

Certain electrolyzer and fuel cell technologies require a thermal heat input to function. The thermal heat requirement is based on the amount of energy required to bring room temperature air to the average operating temperature of each technology type [290], [291]. The main purpose of this thermal heat is to ensure the thermal stability for the different technology

types. The constraint can be seen in Equation 40 to Equation 41 with tech being either the electrolyzer or fuel cell and the parameters detailed in Table 21. The $\eta_{thermal}$ is the thermal efficiency of the technology to maintain the heat while operating. The $P_{tech_heat_k,t}$ is the extra heat required from the electrical furnaces to ensure the minimum heat requirement is met.

$$\eta_{thermal} * P_{tech_k,t} + P_{tech_heat_k,t} \geq Minimum_{heat} * P_{tech_k}^{cap} \quad \text{Equation 40}$$

$$\sum_k P_{tech_heat_k,t} = P_{EF_nonren,t} + P_{EF_ren,t} \quad \text{Equation 41}$$

The $Minimum_{heat}$ is determined by considering the specific heat capacity of air to heat up from room temperature (25ºC) to the specified operating temperature, this calculation can be seen in Equation 42. A generic calculation using the specific heat of air, 1.01 kJ/kg K, and the change in temperature, ΔT.

$$Minimum_{heat} = C_p * \Delta T \quad \text{Equation 42}$$

Table 21: Thermal Heat Requirement for Solid Oxide and Molten Carbonate Electrolyzers / Fuel Cells.

Technology types	**Operating Temperature**	***Minimum$_{heat}$ (MWh_{heat}/MWh_{H2})***	**Thermal Efficiency**	**Reference**
SOFC	900ºC	0.22	12%	[290]
MCFC	625ºC	0.15	10%	[290]
SOEC	900ºC	0.22	12%	[291]

6.2.3 Objective Function

The objective function, f, minimizes total system wide costs, as expressed in Equation 43. The variables $C_{VO\&M}$, $C_{FO\&M}$, and $C_{Capital}$ are the costs of variable operation and maintenance (VO&M),

fixed operation and maintenance (FO&M), and capital respectively of each technology $tech$ and equipment type k. The VO&M is also dependent on the hourly dispatch at time t.

$$f = \min\left(\sum_{k}\sum_{t} C_{VO\&M_{tech_k}} * P_{tech_k,t} + \sum_{k}(C_{Capital_{tech_k}} + C_{FO\&M_{tech_k}}) * P_{tech_k}^{cap}\right) \quad \text{Equation 43}$$

The annual capital cost is calculated using a capital recovery factor (CRF) that allocates the total capital cost (C_{Total_k}) over the total lifetime (*n*) years of operation, as seen in Equation 44. The CRF is calculated with an 8% annual interest rate [292], r, detailed in Equation 45.

$$C_{Capital_{tech_k}} = C_{Total_{tech_k}} * CRF \quad \text{Equation 44}$$

$$CRF = \frac{r * (1+r)^n}{(1+r)^n - 1} \quad \text{Equation 45}$$

6.3 Description of Economic Analysis and Assumptions

The cost assumptions for the different technologies that can capture ERE for useful purposes are obtained from a variety of sources. The electricity sector values for renewable generation and natural gas technologies come from the NREL ATB data for the electricity sector [259]. The cost and economic assumptions for energy storage and hydrogen technologies come from a variety of sources such as the U.S. Department of Energy. The technology assumptions, such as capacity cost, operation maintenance cost, and efficiencies, are listed in detail in the APPENDIX C.

7 TASK 4 – Evaluate the optimized portfolio for technologies to utilize excess renewable electricity

The overarching goal for this task is to determine the technology portfolios that can meet California's 2030 and 2045 goals, 60% RPS and zero-carbon electric grid, respectively. This is accomplished by spanning the installed amount of renewable capacity to determine both how much renewable generation is required and how much curtailment is optimal.

7.1 2045 Base Case Scenario

This 2045 Base Case Scenario represents an electric grid with no use of natural gas power plants or injection of renewable gas into the natural gas pipeline. This is to ensure a focus on the electricity sector and determine the optimal technology portfolio without influences from the gas system. The use of technologies and technology pathways can be seen in Figure 28, the technology parameters and costs can be found in APPENDIX C Task 4 Technology Parameters.

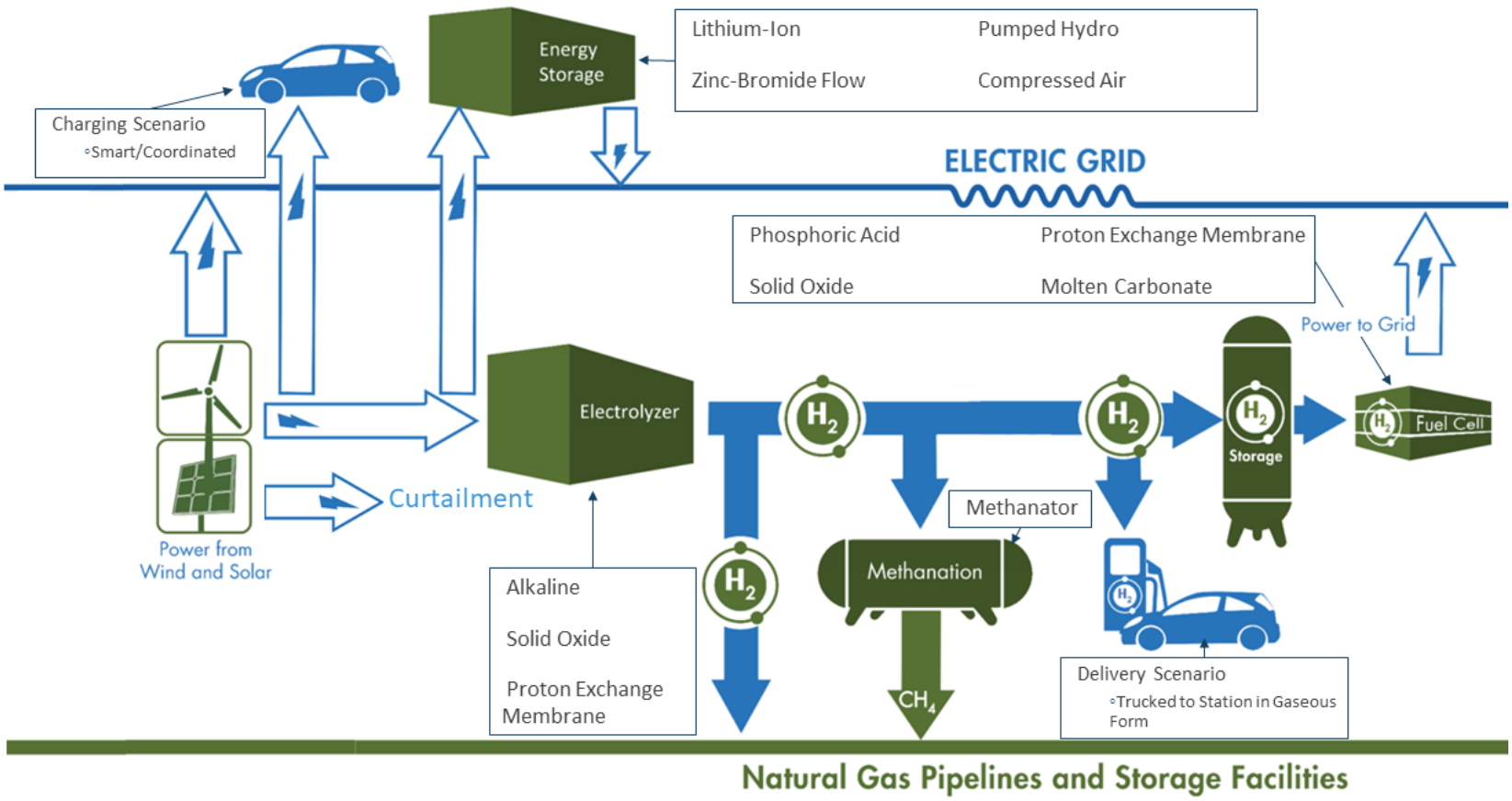

Figure 28: An overview of the technologies and technology pathways considered for the 2045 Base Case Scenario.

7.1.1 2045 Base Case - Total System Cost

The total system cost (TSC) represents the cumulative cost (capital and operating) required (in year 2018 dollars) to build the zero-carbon compliant system over the 26-year span of 2020-2045, and is presented as a function of allowable renewable energy curtailment in Figure 29. The shape of the TSC curve is based on the capacities and selection of technologies to capture and manage ERE that yield the lowest TSC for given levels of allowable curtailed electricity. When no curtailment is allowed – that is when the system is designed to capture all the ERE to meet electric demand that cannot be met directly with renewables, the TSC is at its highest of $3.6 trillion. Allowing increasing amounts of curtailment while complying with the zero-carbon electricity goal significantly decreases the TSC until a minimum of $1.8 trillion is reached when curtailment equivalent to 48% of the annual electric load is allowed, representing an almost three-fold reduction from the case where no curtailment is allowed. As the allowable curtailment increases, however, the TSC rises slightly since significant wind and solar capacity is being installed while providing little incremental benefit for offsetting the costs of energy storage technologies. However, even with allowable curtailment equal to 100% of annual electric load, the TSC is below $2 trillion - half of the TSC when no curtailment is allowed, owing to the significant cost decreases in wind and solar projected for the future.

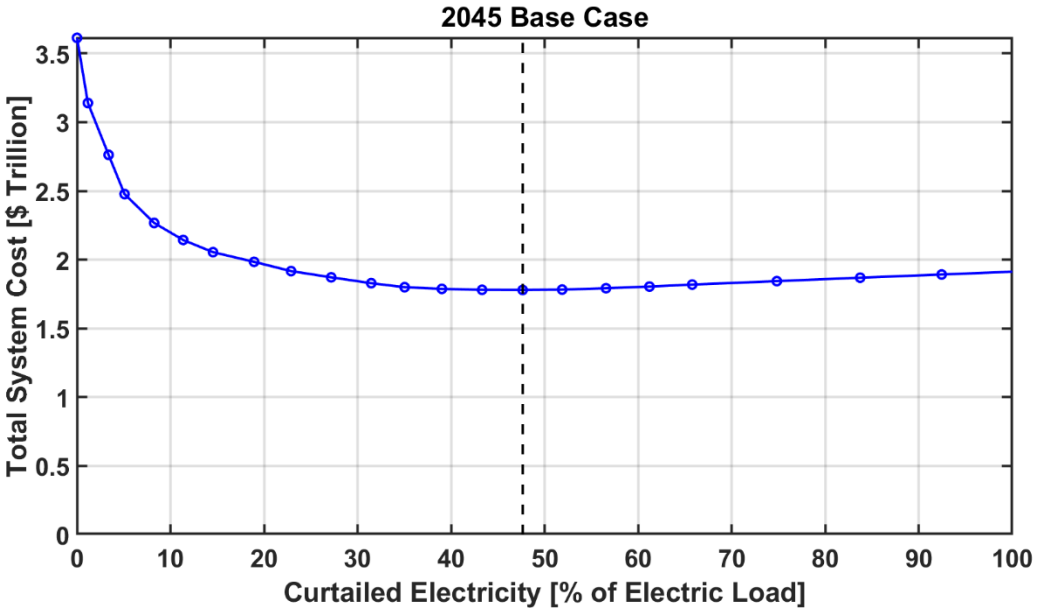

Figure 29: The total system cost in trillions of dollars at varying percent of renewable curtailment.

The variability and intermittency of renewable generation throughout the year is what results to the high amounts of curtailed electricity, as seen in Figure 30. The figure shows the hourly profile of the curtailed electricity for the lowest cost at 48% curtailment level. This figure shows that there is high curtailment of renewable electricity in the middle of the year, during days 75 to 200. However, at the end of the year, from days 200 to 350 there is lower curtailment of renewable generation with almost no curtailment around day 350. This is also little to no curtailment from the beginning of the year to day 25. These moments of little to no curtailment dictate the availability of renewable generation to directly meet the electric demand. Long duration storage can capture the curtailed electricity from the middle of the year for use at other times of the year. The 48% curtailment level shows a least cost optimal system that best utilizes long duration storage for times when there is little to no curtailment and curtailment of lower cost renewable generation when there is excess availability of renewable generation. The

operation of the energy storage technologies is further described in the 2045 Base Case - Lowest Cost (48% curtailment) Portfolio Mix Hourly Operation section.

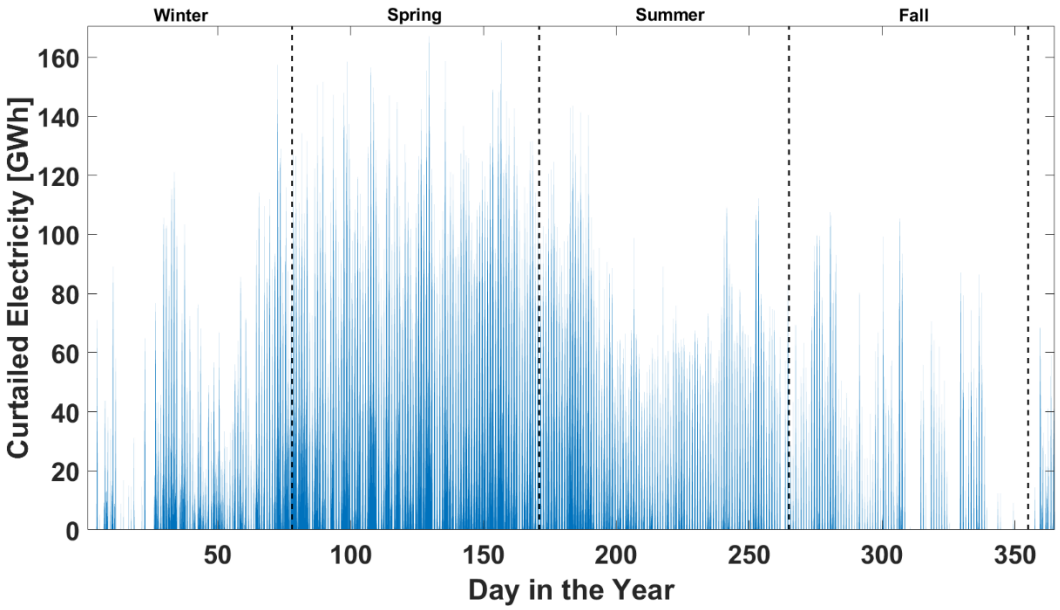

Figure 30: The hourly profile of curtailed electricity for the minimum cost scenario resulting in 48% curtailment of the electric load.

7.1.2 2045 Base Case - Technology Portfolio Mix

The distribution of how ERE is captured or curtailed can be seen in Figure 31. At lower allowable curtailment levels up to the equivalent of 15% of the annual electric load, the cost-minimal approach is to capture the majority of ERE in lithium-ion batteries, with the remainder utilized in produced-gas ES technologies such as AECs and a small amount in SOECs. This occurs since when the availability of ERE is relatively low, using technologies that capture ERE and discharge it with a high round-trip efficiency, which is important to maximize the amount of ERE that is delivered to the electric load. However, even with relatively low ERE levels, lower

efficiency technologies for produced-gas energy storage are still used due to their ability to better compensate for seasonal mismatches between renewable generation and load and the need to produce hydrogen for FCEVs.

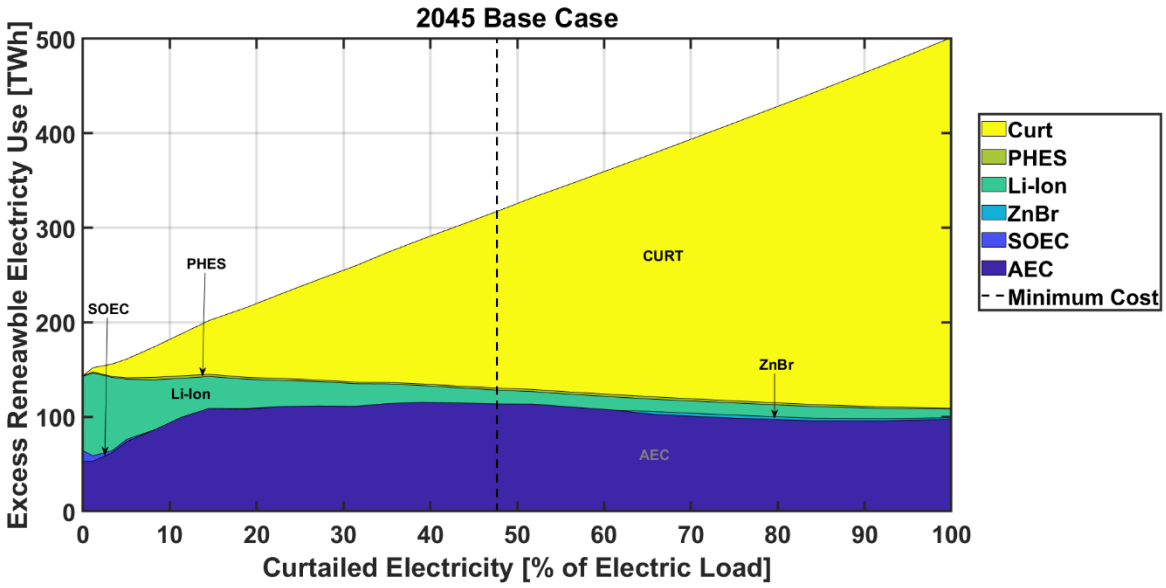

Figure 31: The portfolio of technologies which consume excess renewable electricity for 2045. Alkaline Electrolyzer – AEC, Solid Oxide Electrolyzer – SOEC, Zinc Bromide Battery Energy Storage – ZnBr BES, Lithium-Ion Battery Energy Storage – Li-Ion BES, Pumped Hydro-powered Energy Storage – PHES, Compressed Air Energy Storage – CAES, Curtailed Renewable Electricity – CURT

Above allowable curtailment levels equivalent to 15% of the annual electric load, the cost-minimal portfolio of ERE-capturing technologies shifts dramatically to reduce the amount of ERE captured in Li-Ion BES and to increase the amount captured in electrolyzers – particularly alkaline electrolyzers to store hydrogen in underground storage. This occurs since when ERE is abundant, the round-trip efficiency is less of a driving factor relative to the ability to store large amounts of energy for long duration storage cheaply. A key difference between battery storage and produced-gas storage is influential here. To increase the energy storage capacity of the battery

fleet, the power capacity of the fleet must also be increased even if it is not needed since conventional batteries have limited and fixed energy-to-power capacity ratios. For produced-gas storage, however, the energy and power capacities are not fixed and can be increased independently of each other. Since hydrogen storage either underground or in natural gas pipelines is relatively cheap and large-scale, relying on produced-gas storage enables increasing the energy capacity without incurring costs to increase the power capacity, the latter of which dominates costs for produced-gas storage. Profiles for the dispatch of different energy storage technologies are elaborated on in the 2045 Base Case - Lowest Cost (48% curtailment) Portfolio Mix Hourly Operation section.

The distribution of how the electric demand is met either directly by renewable resources or energy storage discharge is presented in Figure 32. Across all allowable curtailment levels, most of the electric demand is met directly by zero-carbon generation from wind, solar, geothermal, and hydropower without the need for an energy storage technology, and this proportion increases with increasing allowable curtailment levels. Below a 15% allowable curtailment level, most of the electricity not directly met by renewables is served by discharge from lithium-ion batteries, with the remainder met by produced hydrogen converted back to electricity in SOFCs.

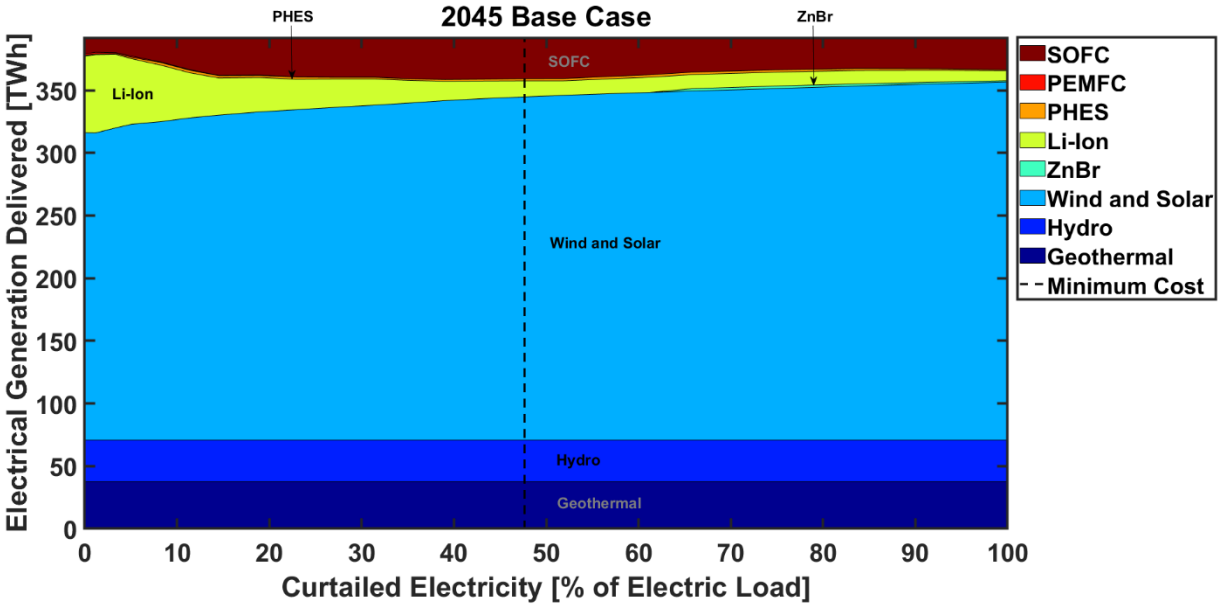

Figure 32: The portfolio of technologies which generate electricity to the electric load.

The power capacity for electrical generation technologies is shown in Figure 33. As in the scope of this study, the capacity for wind and solar increases with the allowable curtailment level. Li-Ion BES contributes most of the installed electricity generating capacity below the 15% allowable curtailment level. Above this, the capacity of dispatchable technologies, represented as those at the top of the graph (SOFC, PEMFC, Li-Ion, CAES, PHES, and ZnBr) remains relatively constant. Despite the large increase of renewable capacity, there is a consistent need for dispatchable capacity due to the inability of renewable generation to match electric demand, no matter how large the increase in renewable capacity.

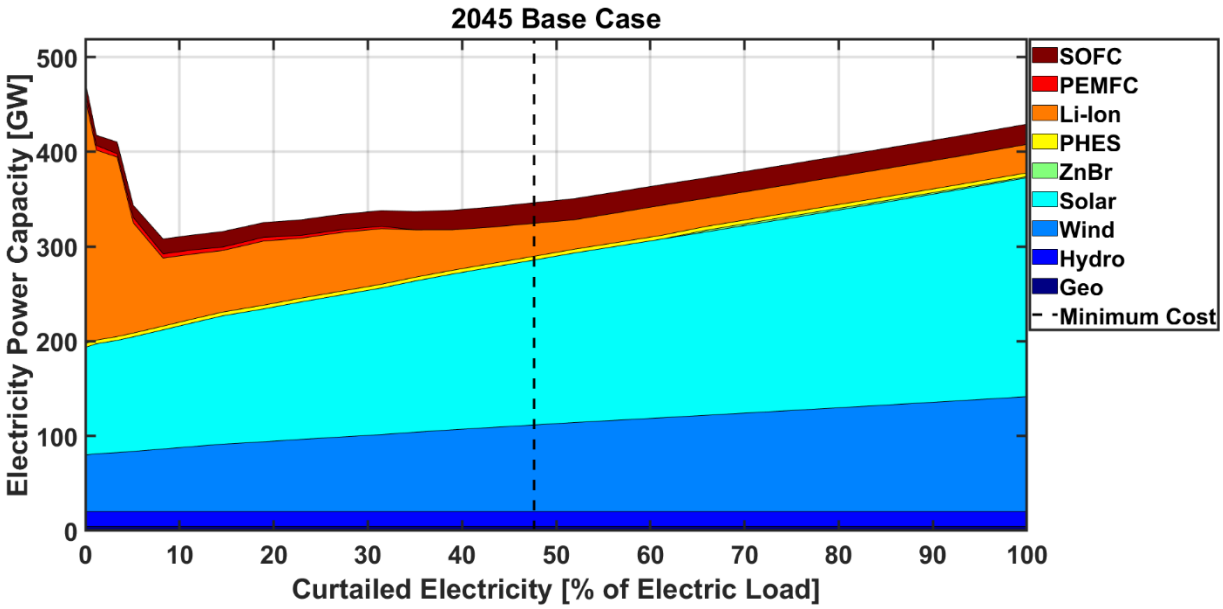

Figure 33: The distribution of installed capacity for technologies meeting the electric load demand.

Hydrogen produced for Fuel Cells and Fuel Cell Electric Vehicles

The electrolyzers produce hydrogen for both FCEVs and P2G2P. The amount of hydrogen produced for FCEVs is dependent on the projected 2045 vehicle deployment and does not change with renewable generation, the hydrogen produced for P2G2P is relative to need for dispatchable electricity which is dependent on technology portfolio. The relative amount of hydrogen produced for P2G2P as compared to FCEVs is shown in Figure 34. This trend of hydrogen produced for P2G2P correlates to the mix of SOFCs, shown in the main manuscript.

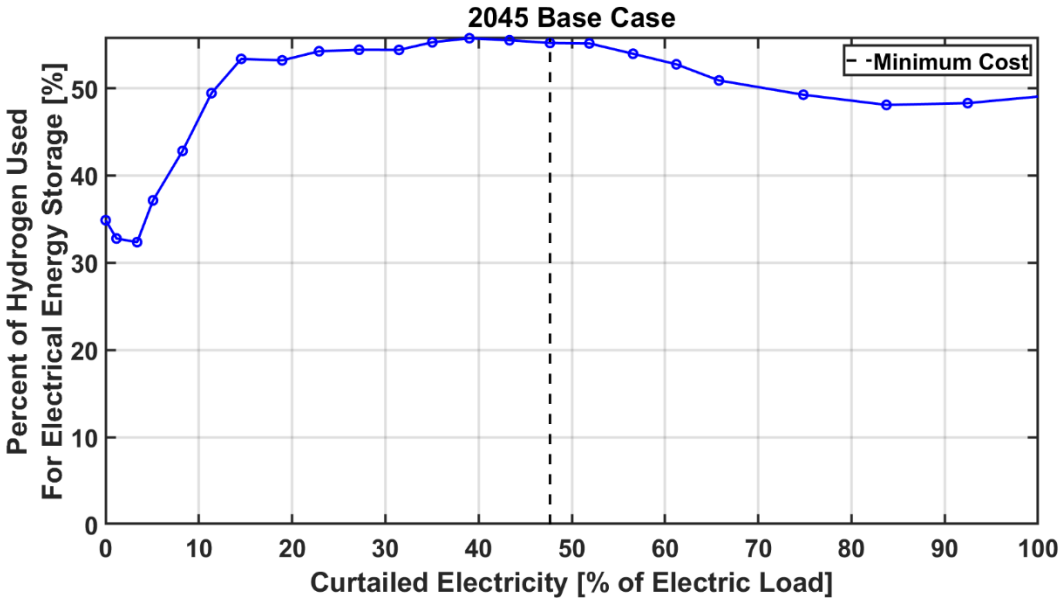

Figure 34: The percent of total hydrogen produced for P2G2P.

At the cost-minimal allowable curtailment level of 48%, approximately 55% of the hydrogen produced is used for grid energy storage rather than for FCEVs.

7.1.3 2045 Base Case - Lowest Cost (48% curtailment) Portfolio Mix Hourly Operation

The lowest cost portfolio mix, the minimum cost, case is with the curtailed electricity of 48%. To have a better understanding of this case, the hourly dispatch of the energy storage technologies is analyzed at a closer level. This will help determine the duration of storage of each energy storage technology.

The hourly profiles for the state of charge in each of the different energy storage systems for the entire year is presented for the case with the cost-minimal allowable curtailment level of 48% of annual electric load in Figure 35. An increase in state of charge correlate to the charging of the energy storage technology; and a decrease in state of charge correlates to the discharge

of the energy storage technology. For all energy storage technology types, there is minimal need for energy storage during the middle of the year, which is approximately during summer, when there is ample availability of renewable generation. The main need for energy storage is during the winter and fall, beginning and end of the year. There are interesting features to note between how the different energy storage types are dispatched. Lithium-ion batteries typically operate on diurnal cycles during the winter and fall hours, extending to cover somewhat longer timescales during the spring and summer when renewable generation is abundant. Pumped hydropower and hydrogen energy storage show distinct seasonal shifting behavior, where excess renewable generation is built-up throughout the year in the spring and summer, then discharged to cover the shortfall in excess renewable generation in the fall and end of the year.

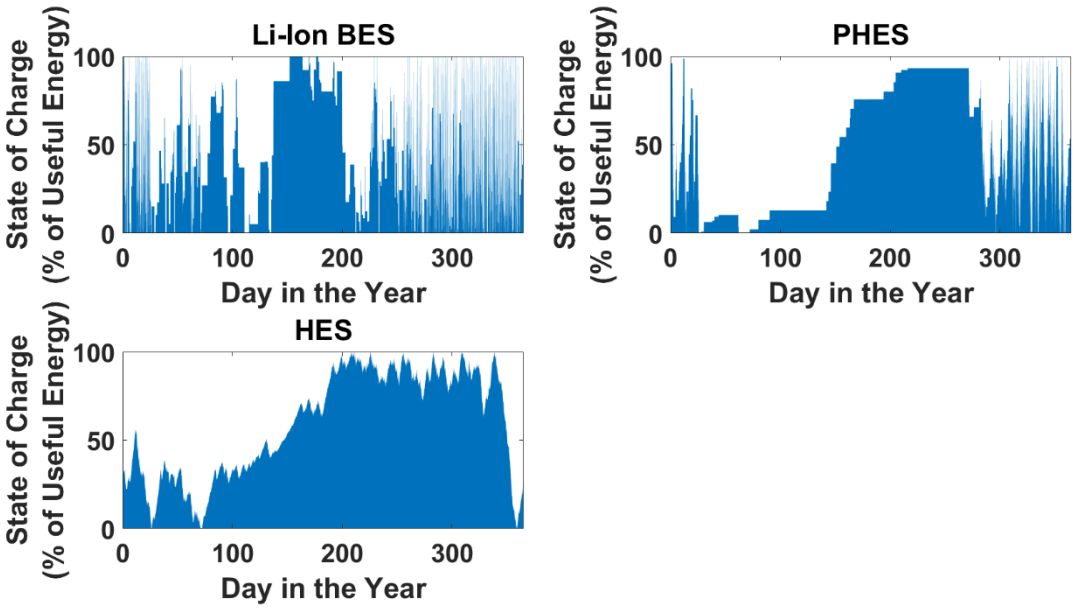

Figure 35: Amount of stored electricity throughout the year in different electrical energy storage types. BES = Battery Energy Storage, PHES = Pumped Hydropower, HES = Hydrogen Energy Storage

Figure 36 presents an inset of the profiles in Figure 35 focused on the last 1/3rd of the year. The primary use of Li-Ion BES is short duration storage. The Li-Ion BES stores energy to maximum capacity for the shortest periods of time, constantly charging and discharging throughout the timespan. Pumped hydro stores electricity for longer times than Li-Ion BES, seen by the relatively constant amount of stored electricity from days 250 to 310, but sees some charging and discharging during days 310 to 365. HES technologies maintain the stored energy for the longest periods of time, shown to respond to a multi-month timescale for charging and discharging, seen by the large discharge through the days 340 to 350. The HES shown in is primarily underground HES; and hydrogen for only P2G2P is shown, which is why it is represented as stored electricity. The energy content for HES is also significantly greater than either Li-Ion BES and Hydro, which can be seen by the different y-axis scale in Figure 36.

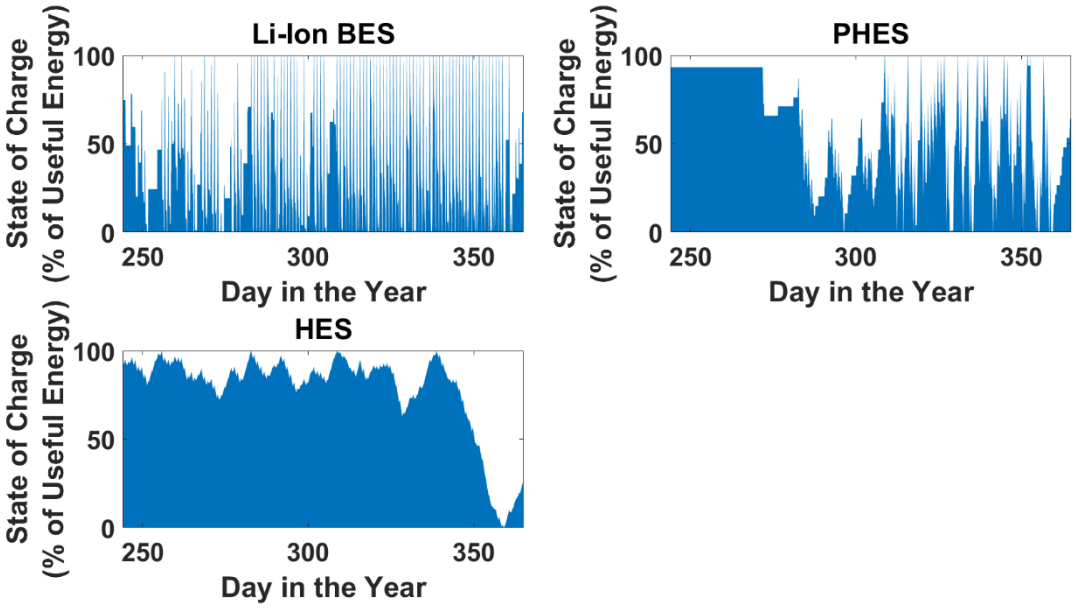

Figure 36: Amount of stored electricity throughout the end of year in different electrical energy storage types.

The hourly electricity generation of each equipment type can be seen in Figure 37. The figures are scaled such that they are comparable to one another. This shows the relative energy generation needs for times when renewable electricity cannot directly meet the electric demand. Li-Ion BES has the highest capacity for electricity generation, followed by SOFCS, and then PHES. The short duration Li-Ion BES has the highest capacity because it can most easily provide the daily energy storage that is necessary when the renewable generation is so highly dependent on solar, which cannot directly provide electricity at night. The SOFC has the second highest electricity generation due to providing most of the stored electricity generation. The PHES has the lowest electricity generation and the lowest electrical capacity due to having the lowest installation costs which is most cost-effective for the long duration energy storage, although it is limited on energy capacity.

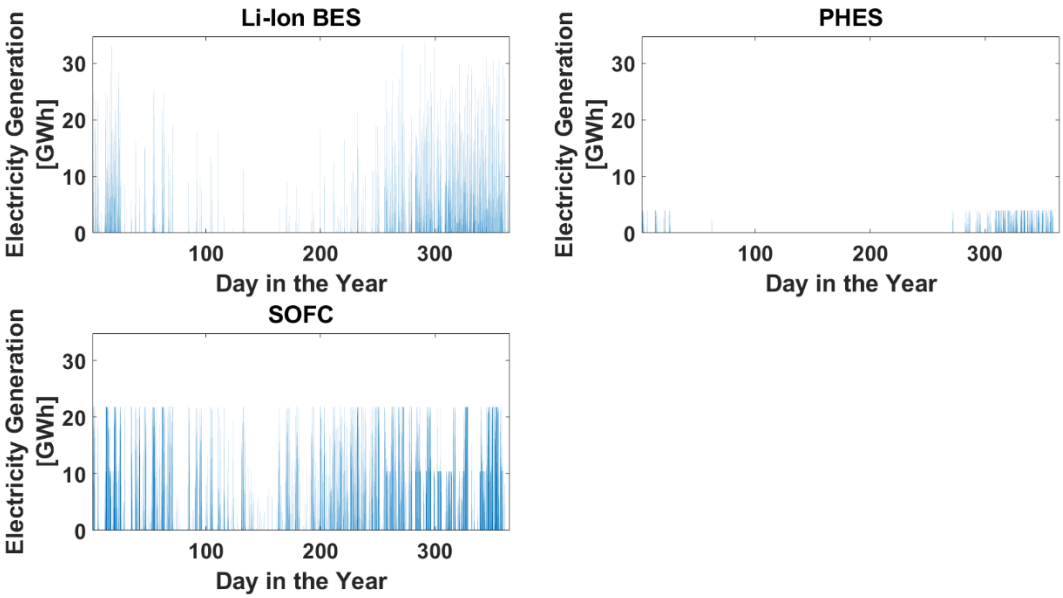

Figure 37: The hourly electricity generation of the different equipment types, scaled to be comparable to each other.

The hourly dispatch of the various electricity generation technologies can be seen in Figure 38. The figure shows how the different technology types operate to balance the electric demand, as well as how the excess renewable electricity is curtailed. The primary curtailed excess renewable electricity is from solar generation, seen by the solar peaks in the middle of each day. A large portion of the renewable generation can be used to directly meet the electric demand. However, during times where there is not enough renewable generation FCs and ES are able to meet the electric demand. The hydropower and geothermal electricity generation is constant throughout the entire year, acting as base load.

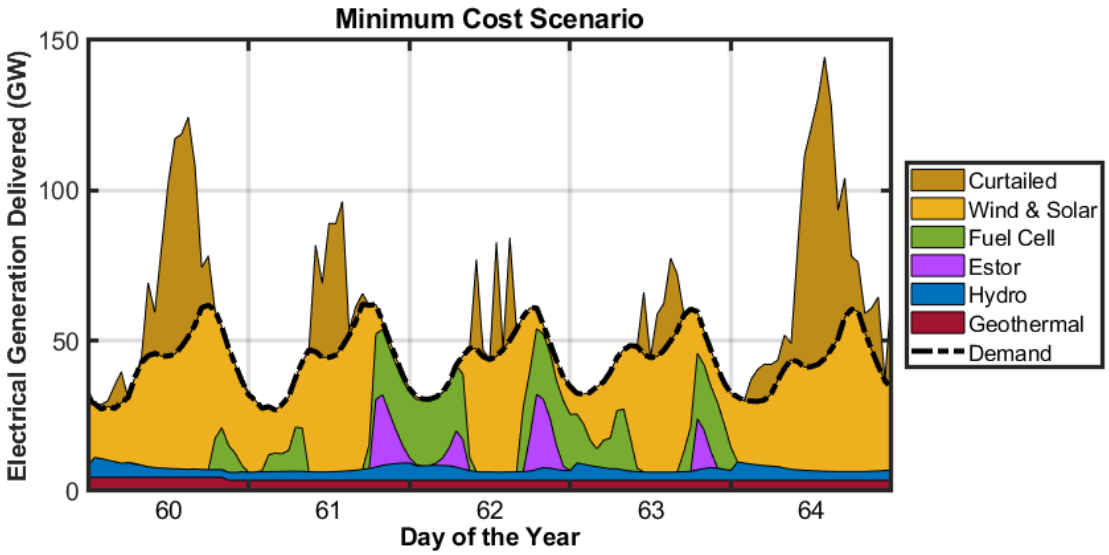

Figure 38: The hourly operation of discharging energy storage technologies, electrolyzers, wind & solar, fuel cells, hydropower, and geothermal relative to the demand and curtailment during days 60 to 65.

To better showcase the variability of renewable generation throughout the year, Figure 39 and Figure 40 showcase times of the year when there is excess curtailment of renewable generation and when there is little to no excess curtailment, days 160 to 165. These days show

that almost all of the electric demand is met directly through renewable generation of wind & solar, with some generation required from fuel cells and energy storage technologies.

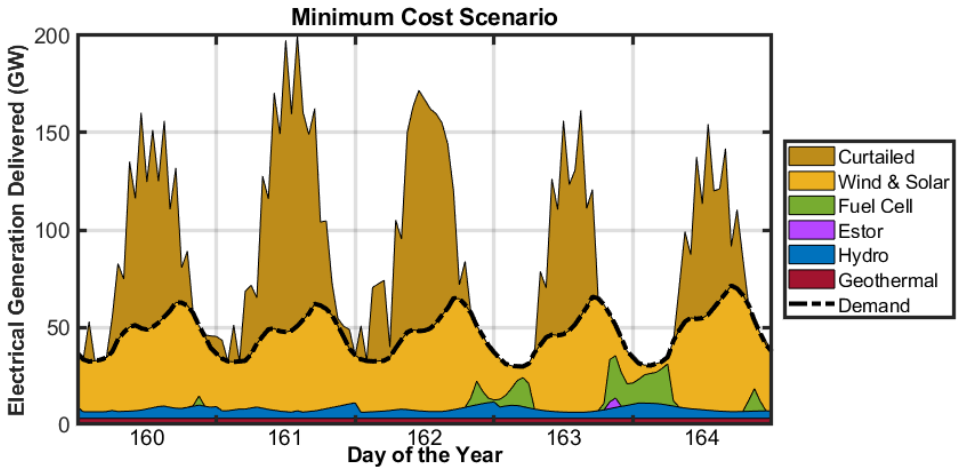

Figure 39: The hourly operation of discharging energy storage technologies, electrolyzers, wind & solar, fuel cells, hydropower, and geothermal relative to the demand and curtailment during days 160 to 165.

In contrast, Figure 40 shows the operation of technologies when there is less availability of renewable generation. The electric demand can be met primarily with renewable generation during the day. However, it seems that almost every night there needs to be dispatchable resources, in this case fuel cells and energy storage technologies, to meet the electric demand. This shows the significant variability of renewable generation as days 345 to 350 are starved of renewable generation as compared to days 160 to 165.

To better understand the use of ERE for days 345 to 350, Figure 41 shows the operation of energy storage charging and the electrolyzer demand that utilizes ERE. The ERE is being almost completely consumed, except for little curtailment on day 349, to meet the daily electricity and hydrogen demand. This is also representative of the operation of energy storage types, seen in

Figure 36, where there is a large discharge of hydrogen from HES with charging and discharging in Li-Ion BES and PHES.

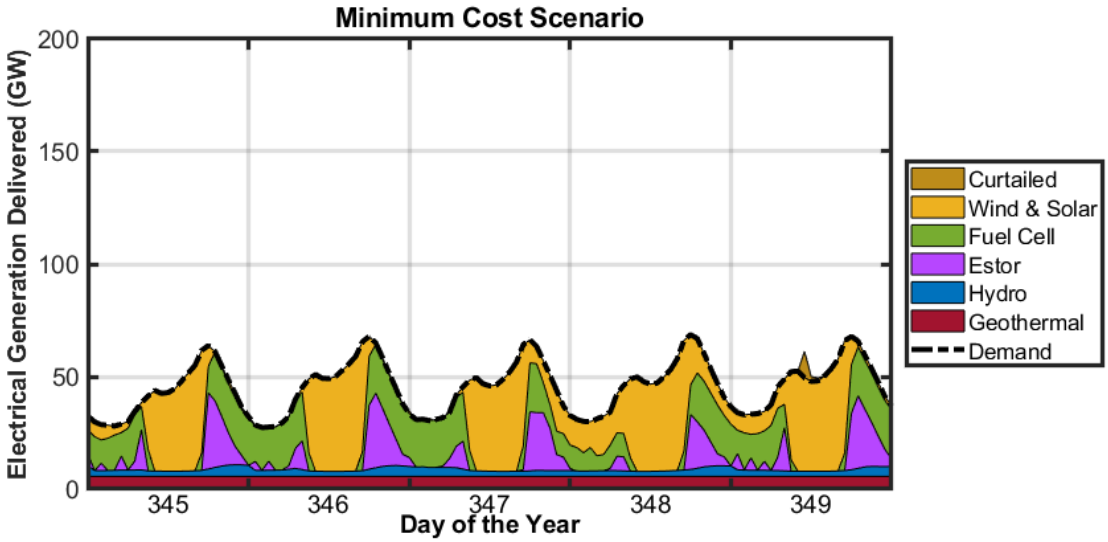

Figure 40: The hourly operation of discharging energy storage technologies, electrolyzers, wind & solar, fuel cells, hydropower, and geothermal relative to the demand and curtailment during days 345 to 350.

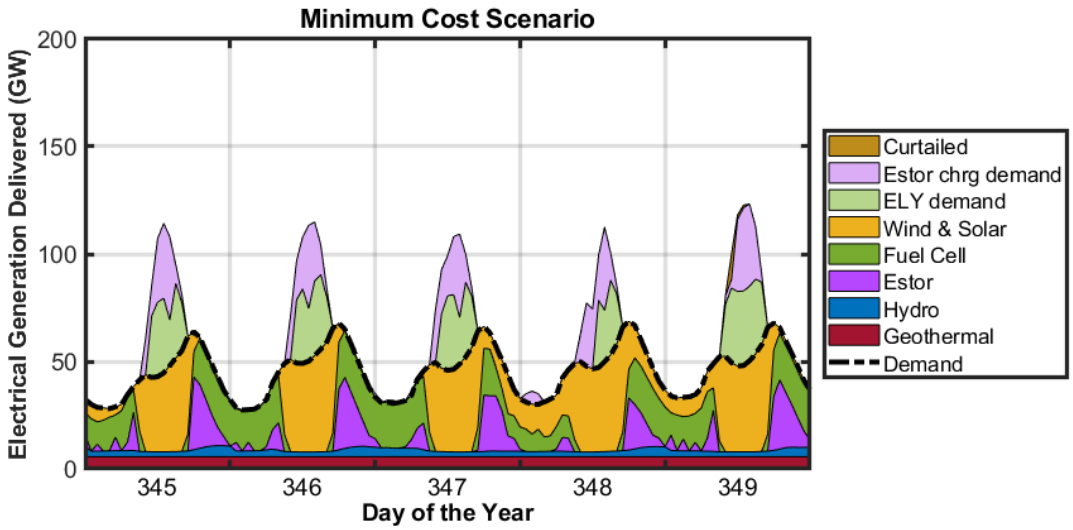

Figure 41: The hourly electrical generation delivered of the various technologies, time of low renewable generation with ERE use for energy storage charging (Estor chrg demand) and electrolyzer for hydrogen production (ELY demand).

The same days are plotted with the split between the solar and wind generation, seen in Figure 42. This shows the differentiation between the solar and wind generation. Solar generation is more consistent, being available every day, and primarily matches to the charging of energy storage technologies, the electrolyzer electricity demand, and curtailment. Wind is more variable and intermittent, with little generation between days 347 to 349. This is also indicative to the low renewable generation during this time of year. In comparison, days 160 to

165 have more wind generation which can directly meet the electric demand at night for most days, as seen in Figure 43.

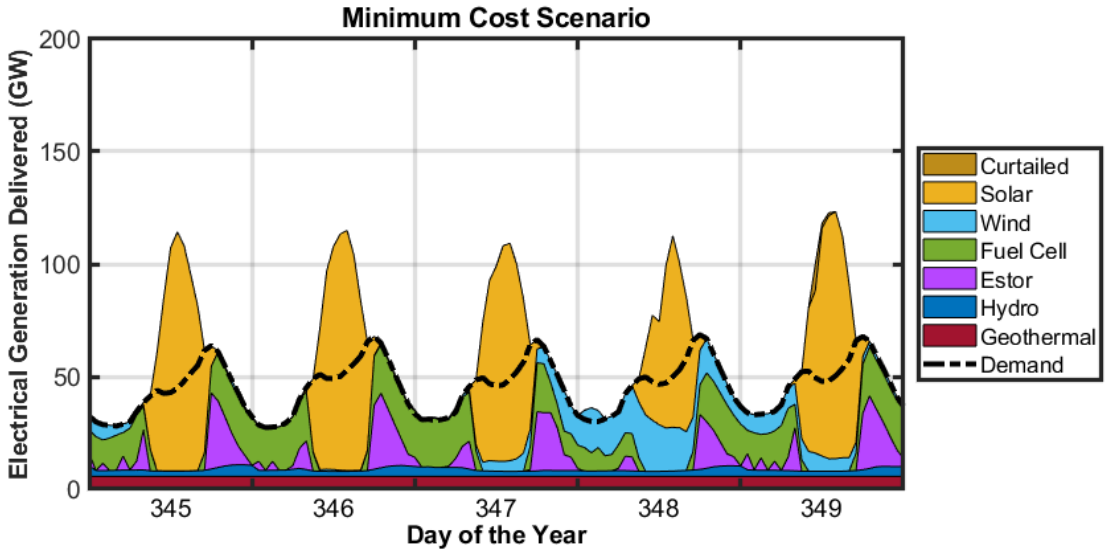

Figure 42: The hourly operation of charging and discharging energy storage technologies, electrolyzers, solar, wind, fuel cells, hydropower, and geothermal relative to the demand and curtailment during days 345 to 350.

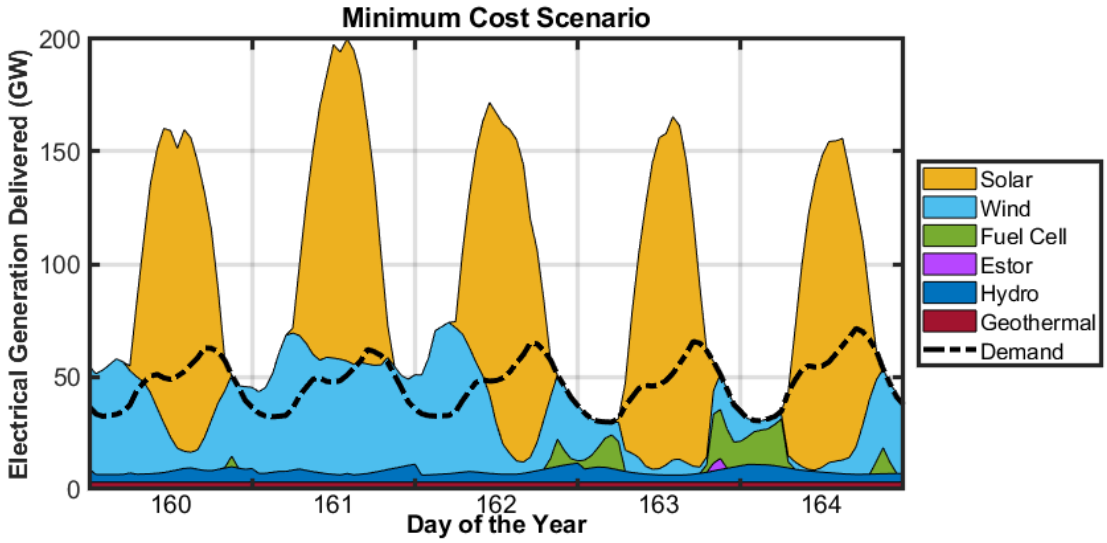

Figure 43: The hourly operation of discharging energy storage technologies, solar, wind, fuel cells, hydropower, and geothermal relative to the demand and curtailment during days 160 to 165.

7.1.4 2045 Base Case – Lower Renewable Generation (14% curtailment) Portfolio Mix Hourly Operation

For the case of lower curtailment levels, the operation of the technologies differ than those with higher curtailment. This lower curtailment level is most likely to be preferred and more likely than the lowest total system cost case of 48% curtailment, as the TSC for a 14% curtailment case is not significantly higher than the 48% curtailment case but has significantly higher curtailment. As compared to Figure 35, Figure 44 shows the hourly state of charge for the selected technologies. The main difference is the operation of the Li-Ion BES. With less availability of renewable generation, the daily storage is more prevalent as there is less renewable generation to directly meet the electric demand. The HES has a more prevalent long duration storage of primarily storing hydrogen in the middle of the year for dispatch during later in the year, when there is less renewable generation available.

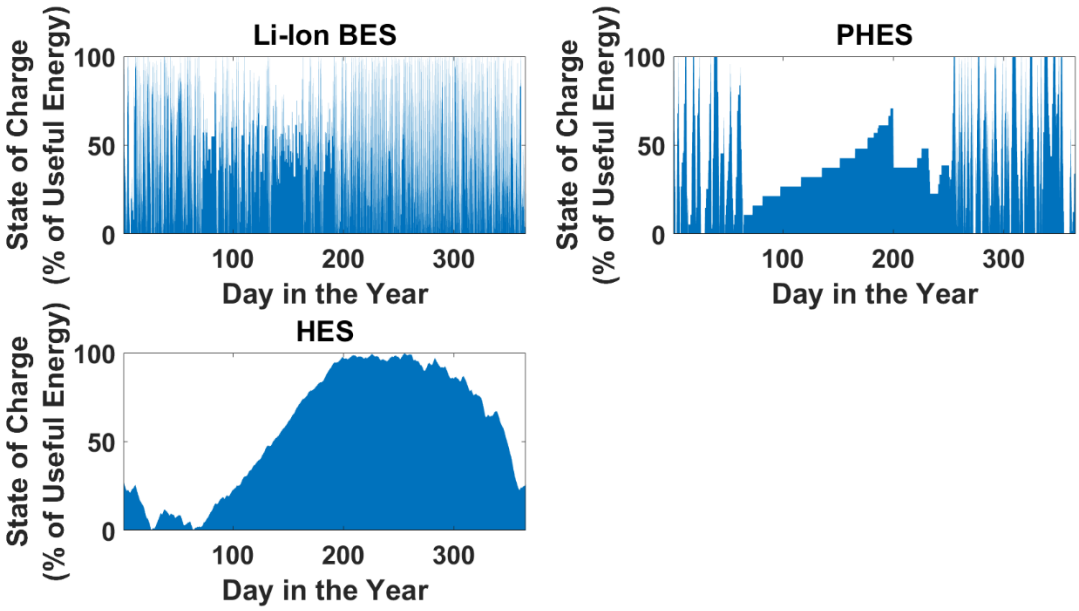

Figure 44: The hourly state of charge for Li-Ion BES, PHES, and HES.

This can also be seen in the hourly operation of the electricity generating and electricity consuming technologies, displayed in Figure 45 and Figure 46. There is overall less curtailment, and more use of energy storage technologies and fuel cells.

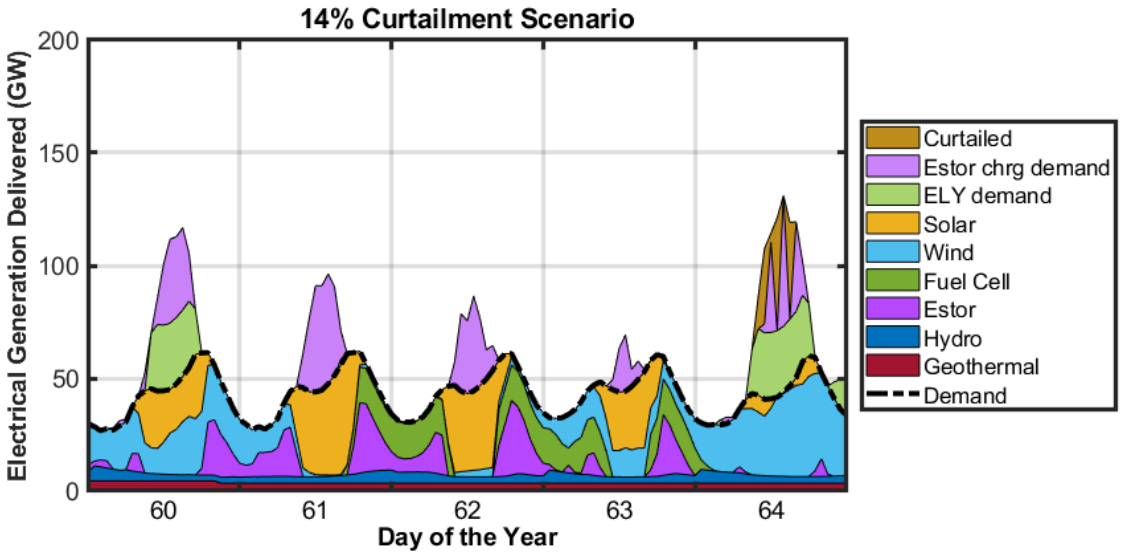

Figure 45: The hourly operation of charging (Estor chrg demand) and discharging (Estor) energy storage technologies, electrolyzers (ELY demand), solar, wind, fuel cells, hydropower, and geothermal relative to the demand and curtailment during days 60 to 65.

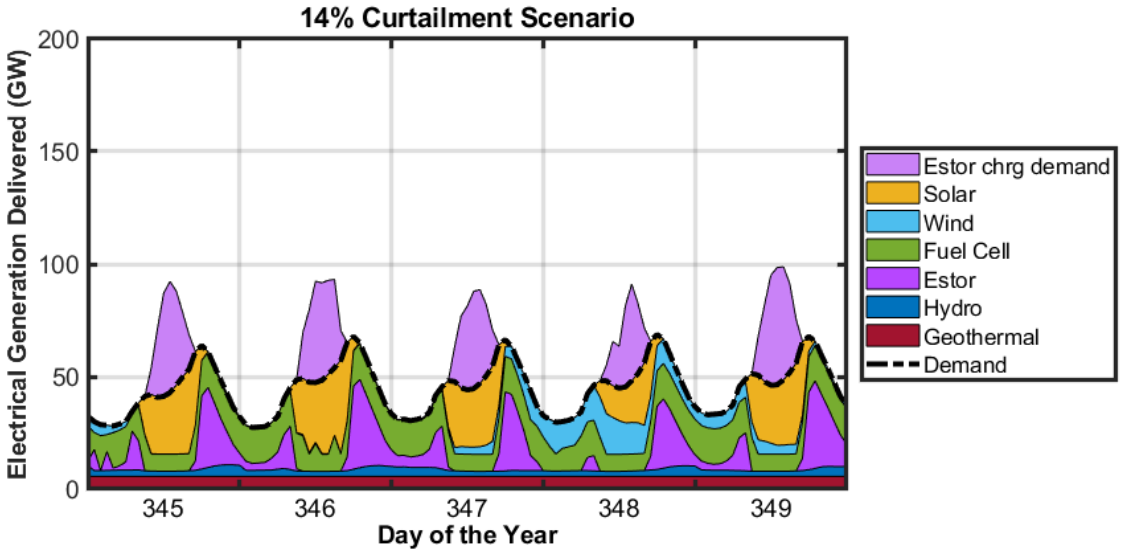

Figure 46: The hourly operation of charging (Estor chrg demand) and discharging (Estor) energy storage technologies, electrolyzers (ELY demand), solar, wind, fuel cells, hydropower, and geothermal relative to the demand and curtailment during days 345 to 350.

7.2 2045 Renewable Gas for NGPP Scenario

The purpose of this scenario is to consider the effects of using the already existing natural gas system for energy storage by producing renewable gas, maximum annual mixture of 10% by volume of renewable hydrogen with renewable methane, for NGPPs. The limitation of hydrogen mixture into the natural gas system is to ensure stability of the gas to be run through conventional combustion technologies. A 5%-20% by volume mixture of hydrogen is the range of acceptable mixture, therefore an average of 10% was taken for this study.

However, it should also be noted that the extent of availability of the currently existing natural gas structure is uncertain and there has been a large push against the use of natural gas system, even in the form of renewable gas, for the future [293], [294], [295]. This is an alternative scenario to consider the potential uses of the natural gas system, should it still be running according to E3 PATHWAY's projection of natural gas use which would affect the ability for 10% by volume hydrogen injection.

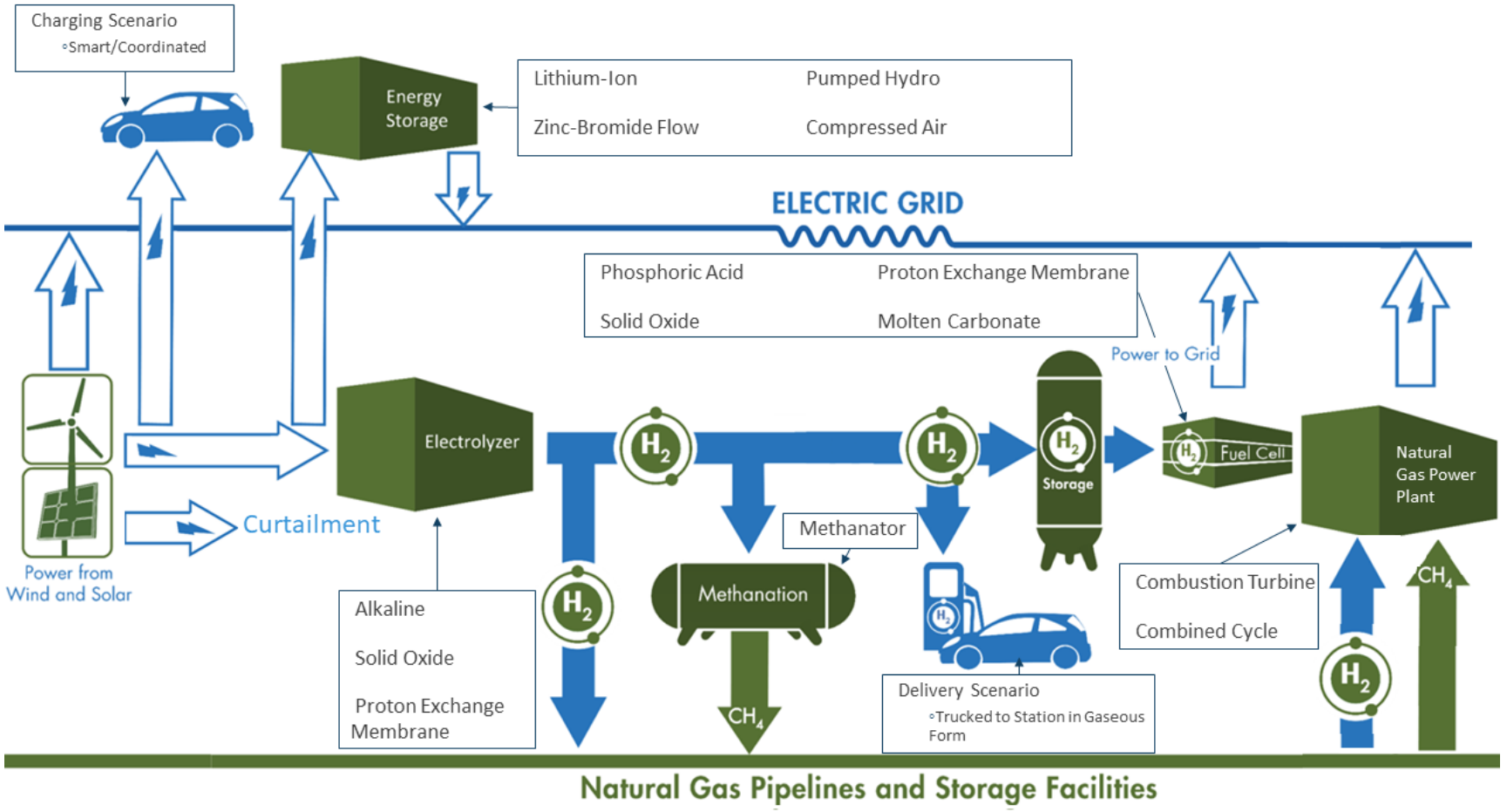

Figure 47: An overview of the technologies and technology pathways considered for the 2045 Scenario with Renewable Gas Power Plants.

7.2.1 NGPP Scenario Total System Cost as compared to the Base Case Scenario

The comparison between the TSC between the renewable gas for NGPP scenario versus the base case scenario, which is without the use of NGPP, can be seen in Figure 48. There are two main differences to note. First, the optimal curtailment level is lower in the scenario with NGPP, at around 17% curtailment, as compared to the 48% curtailment for the base case. This is a significant change, primarily due to the ability for renewable gas to store energy more cheaply using the natural gas system as compared to HES, ES, or curtailing renewable electricity. However, since the scope of these scenarios are only considering the electric grid, lower curtailment may not have enough renewable generation to produce renewable gas for non-electric demands. Therefore, the case for a larger curtailment of 48%, when considering other sectors, may be beneficial to produce renewable gas to offset non-electric demands.

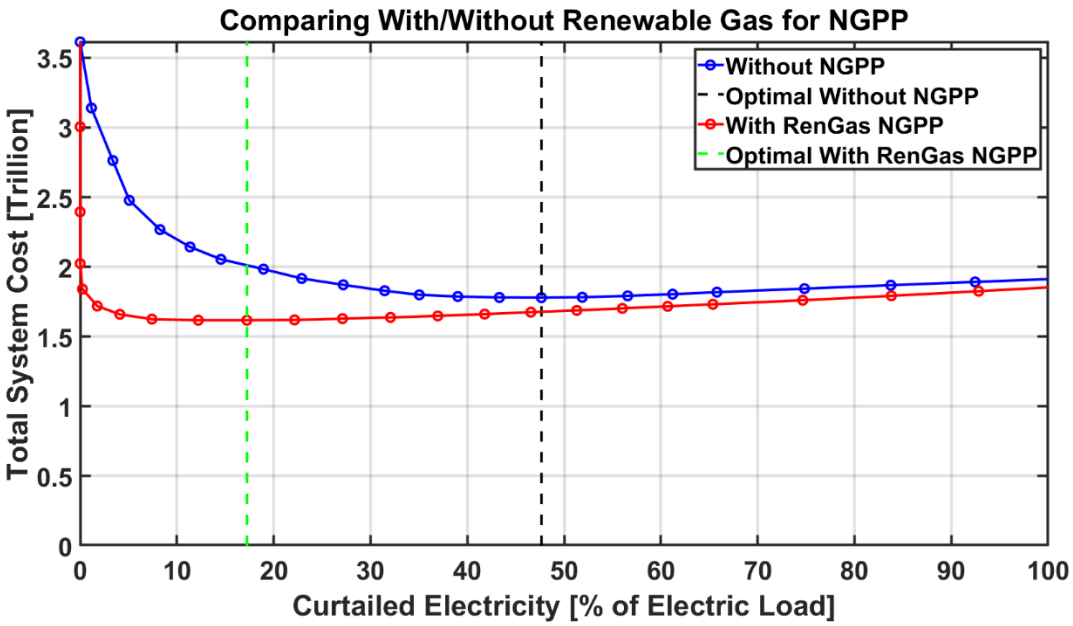

Figure 48: The comparison of total system cost between the scenarios with renewable gas powering NGPP versus the base case with no NGPP.

Second, the TSC is also lower in the case with renewable gas, at a minimum of $1.6 trillion. However, the difference in minimum TSC between the two scenarios is only around 10%, $1.6 trillion compared to $1.8 trillion, even though there is significantly more renewable generation in the base case which could be used for other non-electric uses. This relatively small difference is due to most of the electric demand met directly with renewable generation, which is cheaper than any of the energy storage technologies, therefore affecting only a small portion of the TSC. This can be further seen by the technology portfolios which is discussed in the next section.

7.2.2 NGPP Scenario - Technology Portfolio Mix

Overall, the technology portfolios did not change between the base case and the use of renewable gas for NGPP scenarios. This is apparent in the technology portfolio of ERE use, as

seen in Figure 49. Refer to Figure 31 for the 2045 base case scenario results. The technology portfolio is still the same, with main use of AEC to produce hydrogen and Li-Ion BES and PHES to capture and store electricity. However, there is a different share of ERE use between the technologies. It is clear to see there are some differences between the two plots, with no ZnBr BES used in the cases with renewable gas for NGPP, however it is difficult to see to what degree. Therefore, Figure 50 shows the differences between the two scenarios.

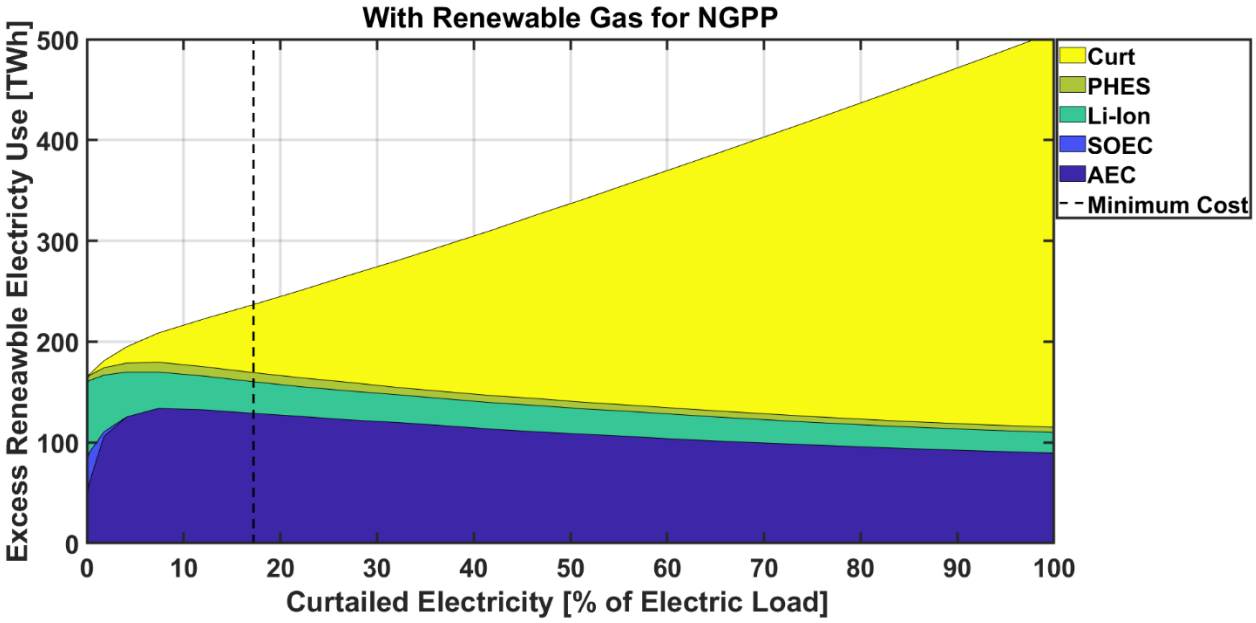

Figure 49: The portfolio of technologies which consume excess renewable electricity for 2045. Alkaline Electrolyzer – AEC, Solid Oxide Electrolyzer – SOEC, Lithium-Ion Battery Energy Storage – Li-Ion BES, Pumped Hydro-powered Energy Storage – PHES, Compressed Air Energy Storage – CAES, Curtailed Renewable Electricity – CURT

Figure 50 shows how the technology portfolio differs between the two scenarios with a positive value representing an increase of technology ERE use in the renewable gas for NGPP scenario as compared to the base case and a negative value representing a decrease of technology ERE use. The figure's data are an interpolation of the previous graphs due to the offset

between the x-axis of the two figures. The previous figures have percent curtailment on the x-axis, which correlate to different amounts of total ERE use. In other words, there is less curtailment in the renewable gas NGPP scenario than the base case scenario at the same amount of total ERE availability, seen by the consistently negative change in ERE use for curtailment (Curt). Therefore, the x-axis in Figure 50 is the amount of ERE in TWh, which is also the y-axis for Figure 49 and Figure 31.

The differences in curtailment between the scenarios is most negative at lower ERE availabilities, such as less than 250 TWh. This is due to higher use of ERE higher that is required to produce the less efficient renewable gas, hydrogen and methane, for use in NGPP as a form of energy storage. This is also seen by the positive change in ERE for almost all technologies at total available ERE less than 175, except for AEC which is in turn replaced with SOECs. Both PHES and Li-Ion BES are higher in the scenario with Renewable Gas NGPP than the base case across all total available ERE. This is due to the use of higher efficient Li-Ion BES and cheap PHES to optimally store electricity for short and medium duration storage while the electrolyzers produce hydrogen for renewable gas in fuel cells and NGPPs for long duration storage. In the base case scenario, fuel cells and HES is the only form of long duration storage. In the renewable gas with NGPP scenario, the production of renewable gas stored in the natural gas system is the only form of long duration storage. Since there are no costs associated with the energy storage capacity for renewable gas, due to the use of the existing natural gas system, it's able to cost effectively operate only during times when there is little to no renewable generation for short or medium duration storage. Therefore, allowing for more energy storage in BES and PHES to provide short

and medium duration storage. This is in comparison to the base case which utilizes HES which has costs associated with the energy storage capacity. Since there is a large amount of energy storage capacity, it becomes cost effective to use HES for both medium, long, and short duration storage therefore decreasing the storage in BES and PHES.

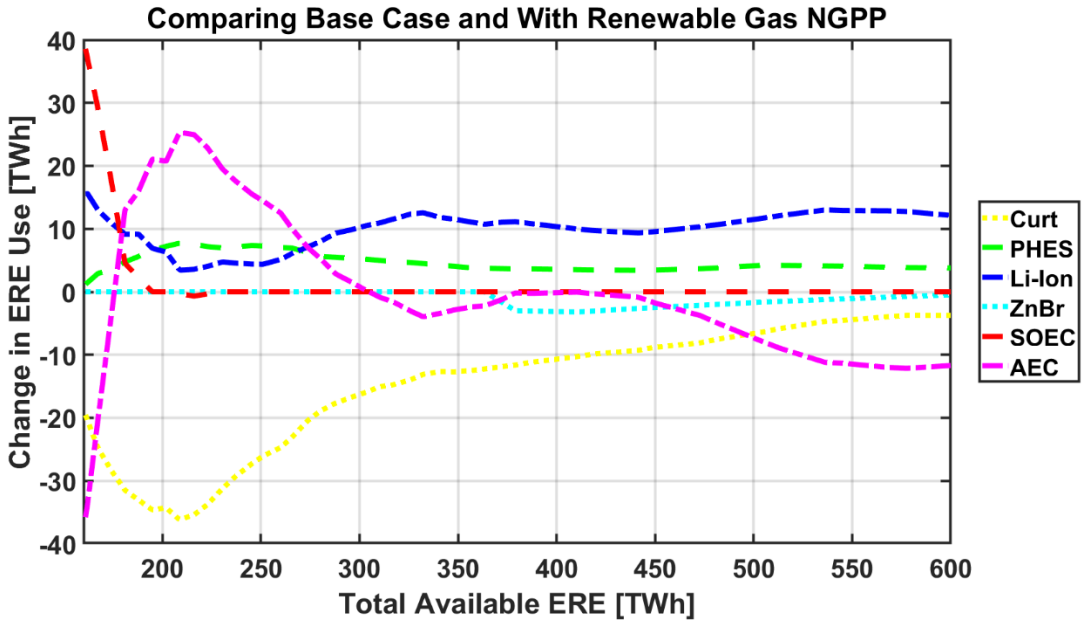

Figure 50: The change in ERE use for each technology types shown in Figure 31 and Figure 49, with a change in the x-axis of this figure to match the y-axis for the previous figures.

The technology portfolio for electricity generation for the renewable gas for NGPP scenario can be seen in Figure 51, which mimics the base case scenario Figure 32. The mix of technologies differ with the addition of natural gas power plants that take in renewable gas and the lack of ZnBr BES. Generally, the same trends apply with more energy storage required at lower curtailment, but as curtailment increases more of the renewable generation can be used to directly meet the electric demand which in turn decreases the need for energy storage. In the

scenario with renewable gas for NGPP, there is a smaller dependence on SOFC and a larger dependence on PHES, Li-Ion BES, and a new dependence on NGPPs.

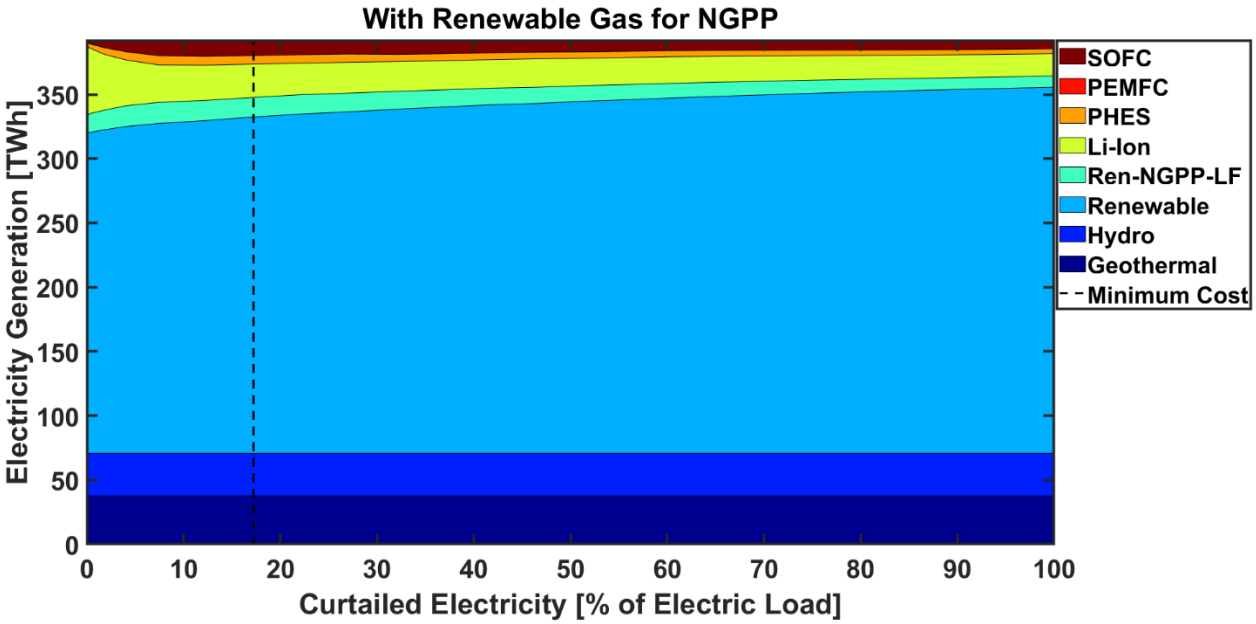

Figure 51: The portfolio of technologies which generate electricity to the electric load.

To better understand the differences between the scenarios, Figure 52 shows the change in electricity generation between the various technology types. Similarly to Figure 50, the data are interpolated from Figure 51 and Figure 32 with a positive value representing more electricity generation from that technology in the renewable gas NGPP scenario as compared to the base case scenario. The x-axis is also changed to represent the total amount of ERE availability.

The negative change in ZnBr BES represents the lack of ZnBr BES in the renewable gas for NGPP scenario as compared to the base case scenario. The positive changes with renewable gas powered NGPP, PHES, and Li-Ion BES correlate with the negative change with SOFCs. In other words, due to the ability for renewable gas to be stored into the natural gas system which can

handle long duration storage, there is a decrease in need for SOFCs to handle the long duration storage.

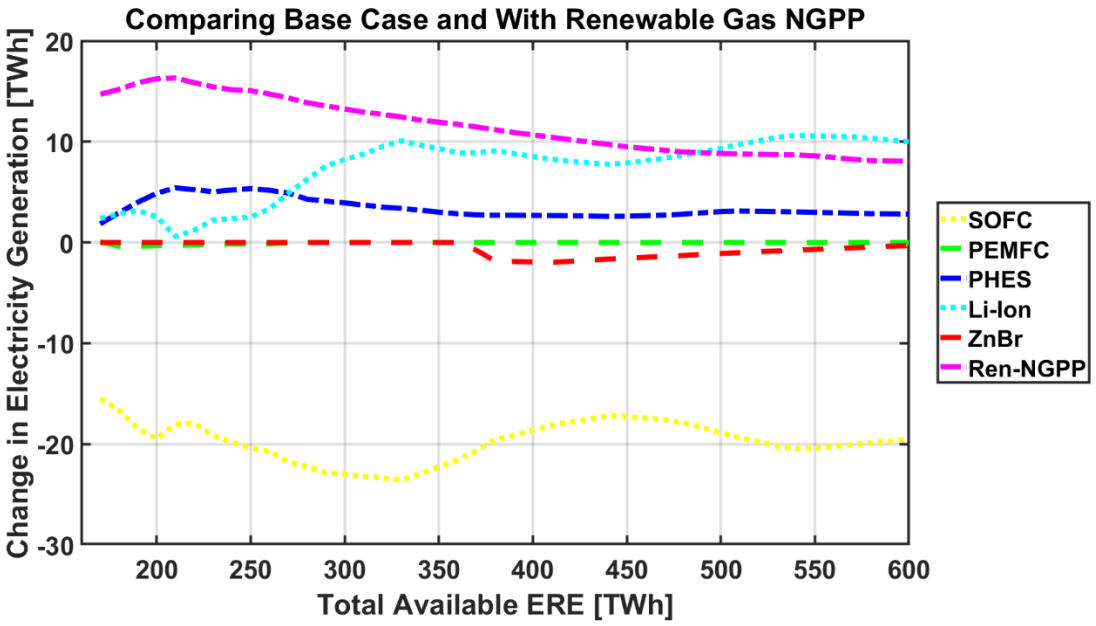

Figure 52: The change of electricity generation technologies, comparing data from Figure 51 and Figure 32

7.2.3 NGPP Scenario - Emissions from Combustion

The optimization does not account for the emission of air pollutants, such as NO_x, which is present in combustion of fuels regardless of the renewability of the fuel. In other words, even though the natural gas power plants are utilizing renewable gas, which results in net zero-carbon emissions, there are still emissions of air pollutants. The primary pollutant considered in this comparison analysis is NO_x, which uses an emission factor based on data from the Environmental Protection Agency, 0.08 tons NOx/ton of fuel [296]. This is much lower as compared to 2018 emissions of 67 thousand tonnes [297].

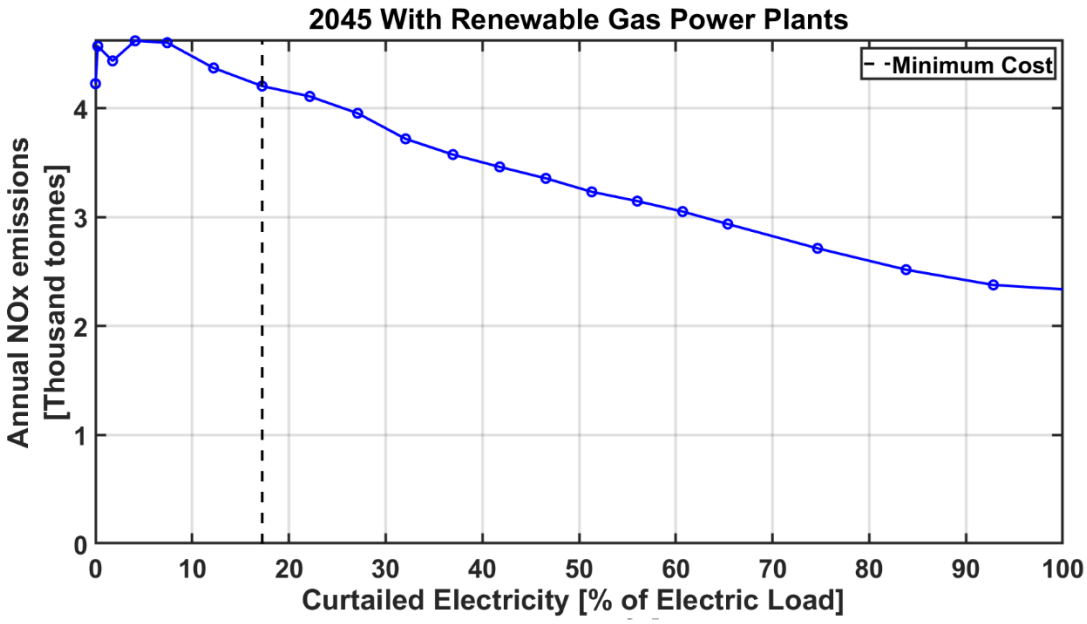

Figure 53: The display of NOx emissions which is directly correlated to the use of NGPPs, decreasing with increasing curtailment.

7.2.4 NGPP Scenario - Lowest Cost Portfolio Mix Hourly Operation

The hourly profiles for the state of charge in each of the different energy storage systems for the entire year is presented for the case with the cost-minimal allowable curtailment level of 17% of annual electric load in Figure 54. Since the curtailment level is lower, of only 17% as compared to 48% for the base case scenario, there is a larger need for storage than the base case due to less renewable electricity that directly meets the electric demand. This can also be seen by the frequent charging and discharging as compared to Figure 35. Renewable gas (mixture of hydrogen and methane) for use in NGPPs is the primary energy storage technology for long duration storage. The renewable gas is produced during the middle of the year, typically

summertime where there is excess availability of renewable generation for discharge at the end of the year where the renewable generation is low. PHES has longer storage duration than Li-Ion BES and HES, but less than renewable gas. PHES also stores a large amount of energy during the summer, but also provides some shorter duration storage by charging and discharging more frequently throughout the first quarter and the last half of the year. PHES also has an ability for long duration storage as there is the ability to utilize existing PHES resources, therefore negating investment costs. However, PHES is limited by the capacity of stored electricity. This limitation prevents further use for long duration storage, but the low costs prioritize its use for long duration storage. Both HES and Li-Ion BES provide shorter duration storage by storing for medium duration storage during the summer but charging and discharging frequently throughout the rest of the year, with Li-Ion BES primarily acting as short duration storage charging and discharging the most frequently.

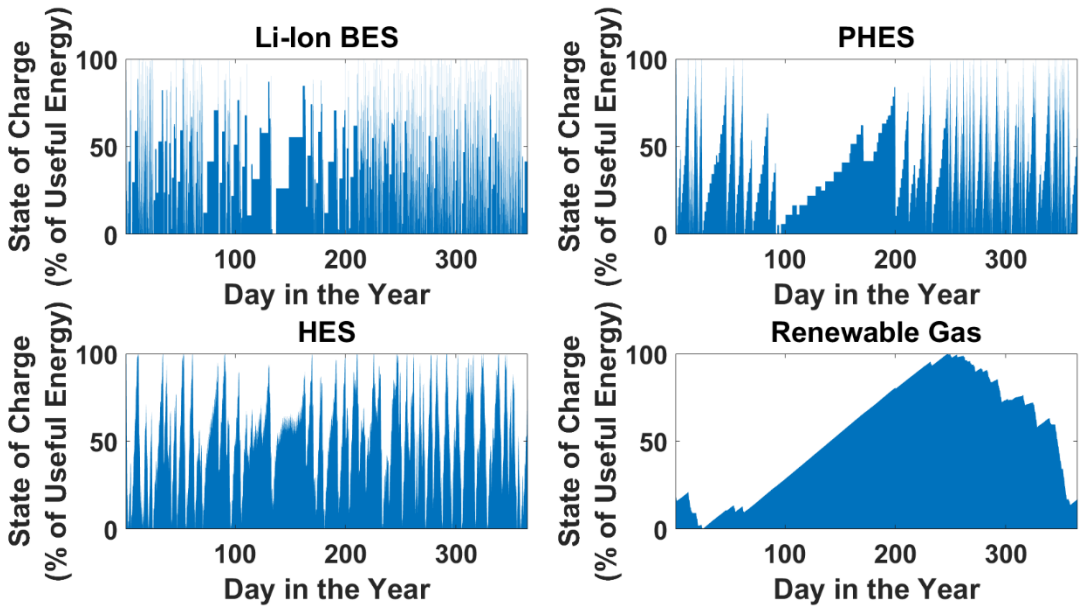

Figure 54: Amount of stored electricity throughout the year in different electrical energy storage types. BES = Battery Energy Storage, PHES = Pumped Hydropower, HES = Hydrogen Energy Storage, Renewable Gas = Hydrogen and Methane Mixture

The electricity generation of the technologies that correlate to the energy storage technologies, with SOFC correlating to HES, NGPP correlating to renewable gas storage, and Li-Ion BES and PHES correlating to itself, can be seen in Figure 55. It should be noted that the y-axis is scaled to match across each technology type, this is to ensure proper visual relative comparison of capacity. For example, Li-Ion BES has the highest capacity for electricity generation, followed by NGPP, FC, and last PHES. This also correlates to the annual electricity generation shown in Figure 51.

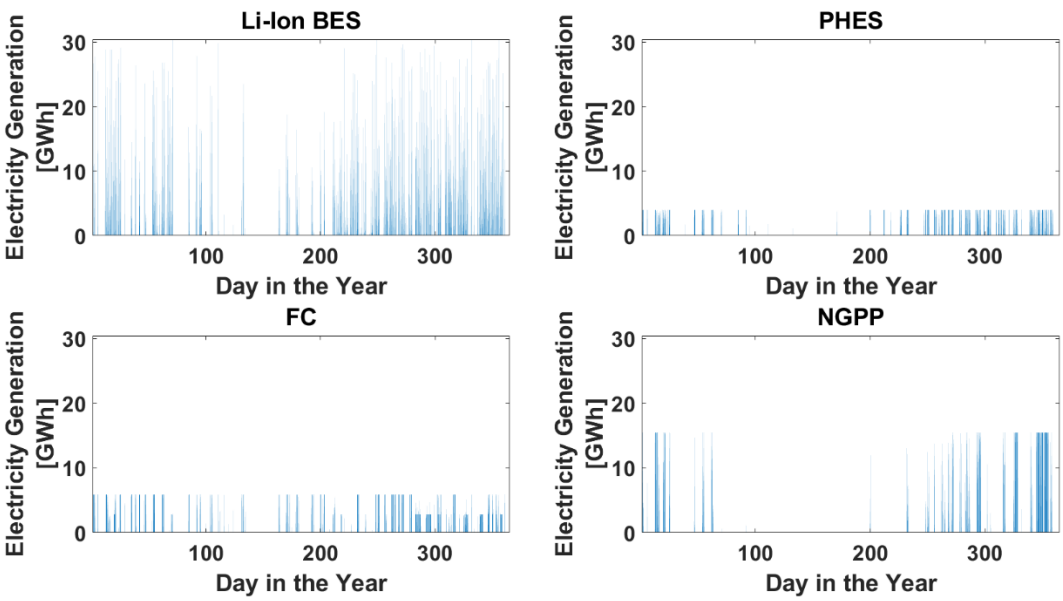

Figure 55: Amount of electricity generation throughout the year in different electrical generation types. Li-Ion BES = Lithium Ion Battery Energy Storage, PHES = Pumped Hydropower, FC = Fuel Cells, NGPP = Natural Gas Power Plant

The empty portion in the middle of the year for PHES and NGPP correlate to the long duration storage, as there is no electricity generation (discharging) during this time. The main purpose of the NGPP is to provide electricity generation during the few times of the year where there is not enough renewable generation to either directly meet the electric demand or to adequately store for short duration. The injection of renewable hydrogen and methane into the natural gas system is an optimal form of long duration energy storage due to its ability to utilize already existing infrastructure with little additional costs, as there are some costs associated with injection renewable gas into the natural gas pipelines. The annual percentage of hydrogen and methane is maintained to by 10% by volume of hydrogen, however this is only achievable due to the natural gas system being filled with natural gas that is used for other technologies. The constraints of annual percentage mixture of hydrogen and methane is only possible because the

hourly constraints of volume percent of hydrogen are based on the entire natural gas system, allowing for periods of more hydrogen injection. In other words, if the renewable gas production and injection into the natural gas pipeline must be hourly constrained to 10% by volume hydrogen and cannot be mixed with existing natural gas, this would no longer be an optimal solution as the constraint limits the ability to store energy into the natural gas pipeline. PHES also focuses on long duration storage mostly generating electricity towards the beginning and ends of the year. It also is the lowest in electricity generation capacity due to its limitations.

FC and Li-Ion BES generate electricity throughout the year with a focus towards the beginning and the ends of the year. These technologies focus on shorter duration storage. Li-Ion BES has the highest electricity generation capacity due to its high efficiencies to store electricity and is optimal to provide short duration storage as the costs for Li-Ion BES are highly dependent on the amount of storage. With longer duration storage, the costs of Li-Ion BES become much higher. FCs provide short duration storage by utilizing the HES that is also used for FCEVs. The FCs have a relatively low amount of electricity generation capacity due to the limitation of HES. If the HES is expanded to incorporate FCs, it increases the costs. But since there is HES for FCEVs the FCs can utilize a portion of the HES to store hydrogen without incurring additional costs.

For a closer look of the hourly operation for the electricity generating technologies, relative to curtailment, Figure 56 shows the operation of various technologies. The use of energy storage and fuel cell is still apparent, but the natural gas power plant seems to be dispatched during peak times when the need for dispatchable technologies is greater. For example, renewable generation can directly meet most of the electric demand on days 60 to 61, with some

dispatch from energy storage and fuel cells. But the night of day 61 to the end of day 63 there is less renewable generation and therefore fuel cells and energy storage technologies are dispatched with the assistance of NGPP that can utilize the large natural gas system for energy storage for those times of peak demand.

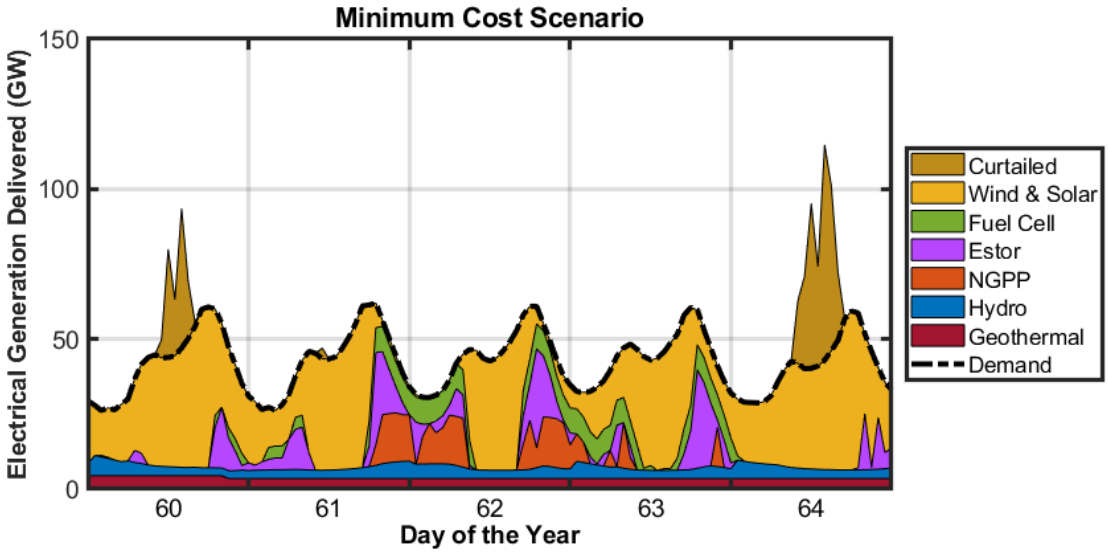

Figure 56: The hourly operation of discharging energy storage technologies, electrolyzers, wind & solar, fuel cells, natural gas power plants, hydropower, and geothermal relative to the demand and curtailment during days 60 to 65.

7.3 2030 Scenario

The 2030 scenario represents a less renewable electric grid with a constraint of a 60% RPS electric grid, as opposed to the 2045 scenario which considered a zero-carbon electric grid. There is also a limit for SMR production of hydrogen to be less than or equal to 40% for vehicle production. There is only one 2030 scenario considered, due to the limitations of renewable generation which does not allow for more flexibility of ERE use. The results here are shown based on the amount of total renewable generation relative to the electric demand. This differs from

the previous results for 2045 which show results based on the percent of curtailment. The purpose of this difference in graphical display is due to the 2030 scenario having little curtailment, due to less installed renewables and a lower penetration of renewables, which cannot properly capture the relevant trends based on curtailment. This also shows how much renewable generation is needed to ensure the 60% RPS. For example, if the total renewable generation is 64% of the total electric demand, that means there is an additional 4% of renewable generation that is needed to ensure a 60% RPS due to efficiency losses from energy storage or from mismatch of renewable generation with electric demand. In addition, since there is no zero-carbon technology restrictions, the use of fossil fuel natural gas power plants is permitted, as shown in Figure 57.

7.3.1 2030 Total System Cost

The TSC represents the cumulative cost (capital and operating) required (in year 2018 dollars) to build the 60% RPS compliant system over the 10-year span of 2020-2030, calculated by subtracting the installation costs of already existing technologies in 2020 based on PATHWAYS, and is presented as a function of total renewable generation, as a percentage of electric load, in Figure 58. The total renewable generation starts at around 61.3% due to the efficiency losses from energy storage that is necessary to achieve a 60% RPS since there are times when renewable generation does not match directly with electric load. Any renewable generation less than 61.3% cannot achieve a 60% RPS electric grid, therefore were not considered. Renewable generation at 61.3% of the electric load result in the highest TSC of $443.7 billion. Installing additional renewable generation resources, to 69.0% renewable generation, allows for a cost optimal TSC

of $414.4 billion, resulting in a 6.7% decrease in TSC from the highest case. Although, it should be noted that even at a lower 62.7% renewable generation, the TSC is $423.3 billion, which is only a 2.2% increase in TSC from the cost-optimal case despite a 9% decrease in renewable generation level. And, at higher renewable generation at 72. 7% of electric load the TSC is $426.9 billion, which is only an 3.0% increase in TSC and 5% increase in renewable generation level from the cost-optimal case. There is low variation of TSC across all cases of renewable generation, seen by the low difference percentages that do not exceed 10% in either renewable generation or TSC. The TSC is dependent on the technology portfolios that utilize ERE to ensure a 60% RPS electric

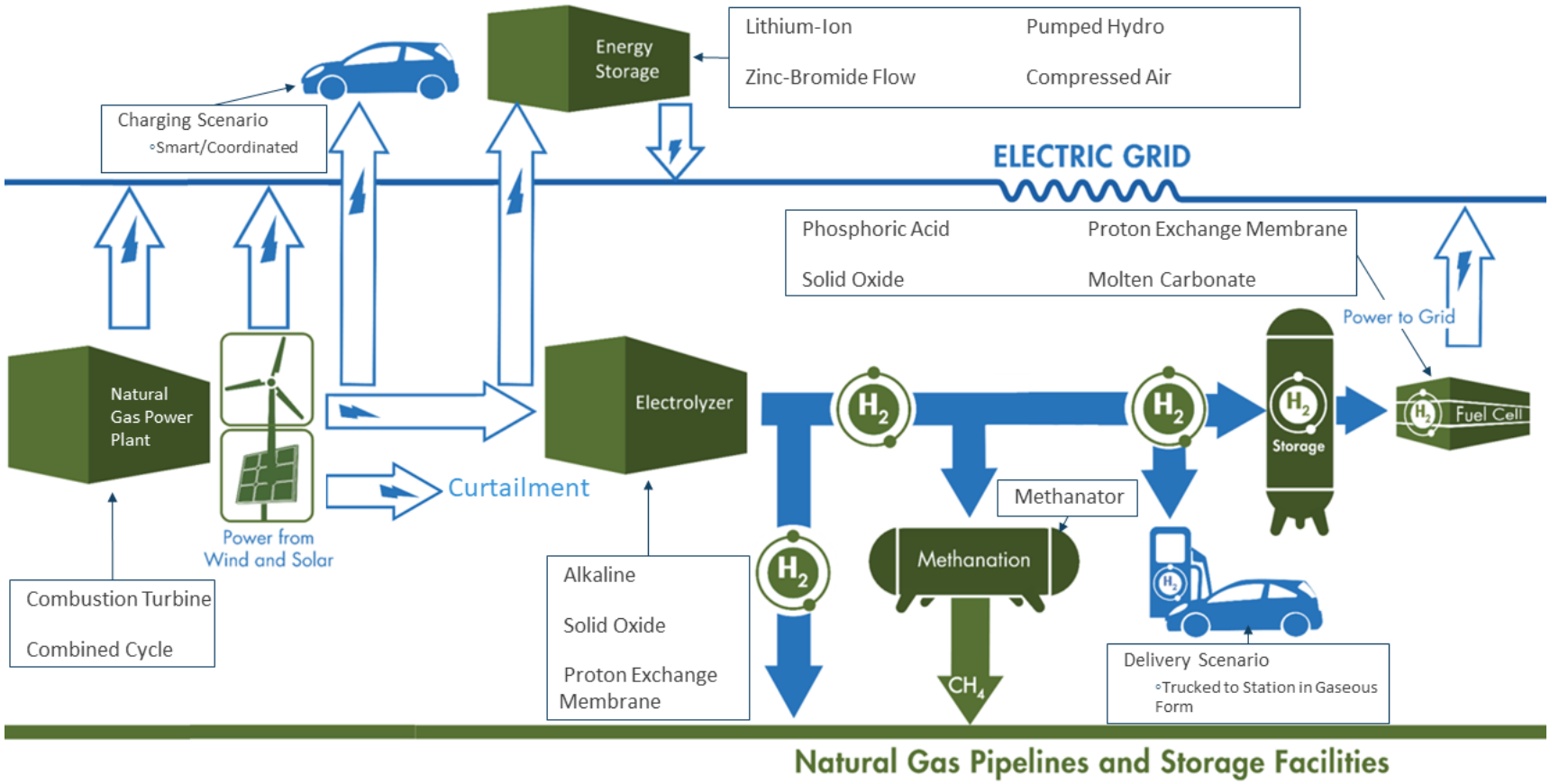

Figure 57: A diagram of the technologies considered for the 2030 scenario.

grid. Overall, there is a slight decrease in TSC from lower renewable generation to higher renewable generation until 69.0% renewable generation as compared to the electric load. For renewable generation higher than 69.0% the electric load, the TSC increases due to the overgeneration of renewables. This result is akin the 2045 case with a decrease in TSC due to the need for more efficient energy storage technologies at lower ERE generation levels and an increase in TSC due to over generation of renewables at higher ERE generation levels.

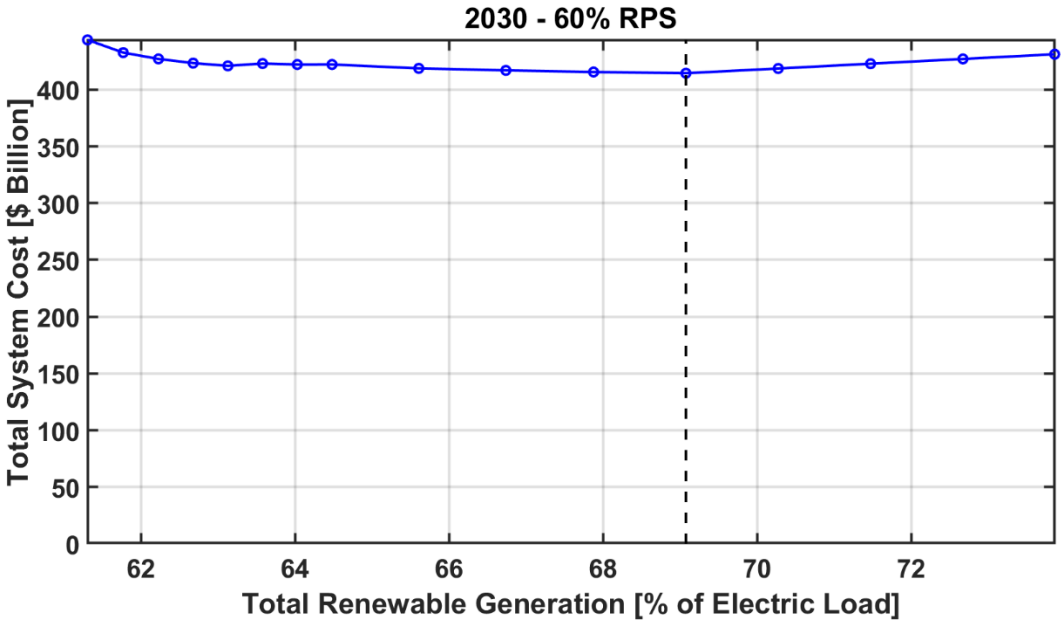

Figure 58: The total system cost vs the amount of excess renewable electricity generation, relative percent to the electric load, for the 2030 scenario.

7.3.2 2030 Technology Portfolio Mix ERE Use

The technology portfolio for closed-form energy storage technologies and curtailment as a mix of ERE use is seen in Figure 59. There is a large portion of ERE used in Li-Ion BES at lower renewable generation with a decrease of use that is replaced with PHES. The overall reduction of

ERE use for energy storage is due to the ability for renewable generation to directly meet the electric demand to meet the 60% RPS electric grid constraint. The transition from Li-Ion BES to PHES is due to more ERE which allows for the less efficient and cheaper PHES to store electricity as opposed to the higher efficient but more expensive Li-Ion BES, similar to the 2045 scenarios. There is a complete switch from Li-Ion BES to PHES at around 69% renewable generation, this is due to adequate renewable generation to store in less efficient PHES. At higher renewable generation, the usage of ERE for storage nears zero, which means that it is possible for renewable generation alone to achieve the 60% RPS. Although, the optimal case utilizes PHES.

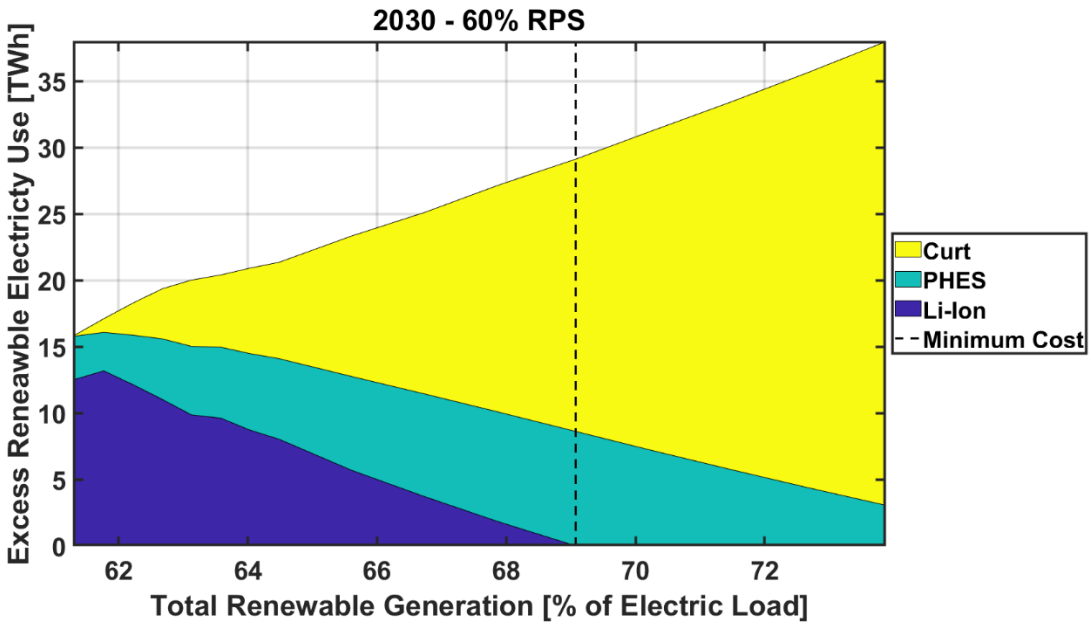

Figure 59: The portfolio of energy storage technologies which consume excess renewable electricity for 2030. Lithium-Ion Battery Energy Storage – Li-Ion BES, Pumped Hydro-powered Energy Storage – PHES, Curtailed Renewable Electricity – CURT

Hydrogen is produced through the use of renewable generation, but is not shown in Figure 59, as hydrogen has multiple methods of production. Most of the hydrogen produced is

used for FCEVs and no hydrogen is stored for use in fuel cells as energy storage. The hydrogen for FCEVs is produced from a variety of means, as seen in Figure 60. The figure shows the different technologies that produce hydrogen and is displayed as a percentage of total hydrogen production. The plot displays how much hydrogen is produced from SMR and electrolyzers. The primary electrolyzer technology is AEC, with use of SOEC at low renewable generation due to the higher efficiency of SOECs, similar to the 2045 results. The electrolyzers are split into the amount of hydrogen produced directly from renewables and those that are not directly from renewables. The electricity that is not directly from renewables can be either from energy storage technologies or natural gas power plants. The optimization choses to have a mixture of both directly and non-directly renewable electrolyzer hydrogen production. This allows the electrolyzers to operate at a higher capacity factor, which in turn optimizes the electrolyzer size.

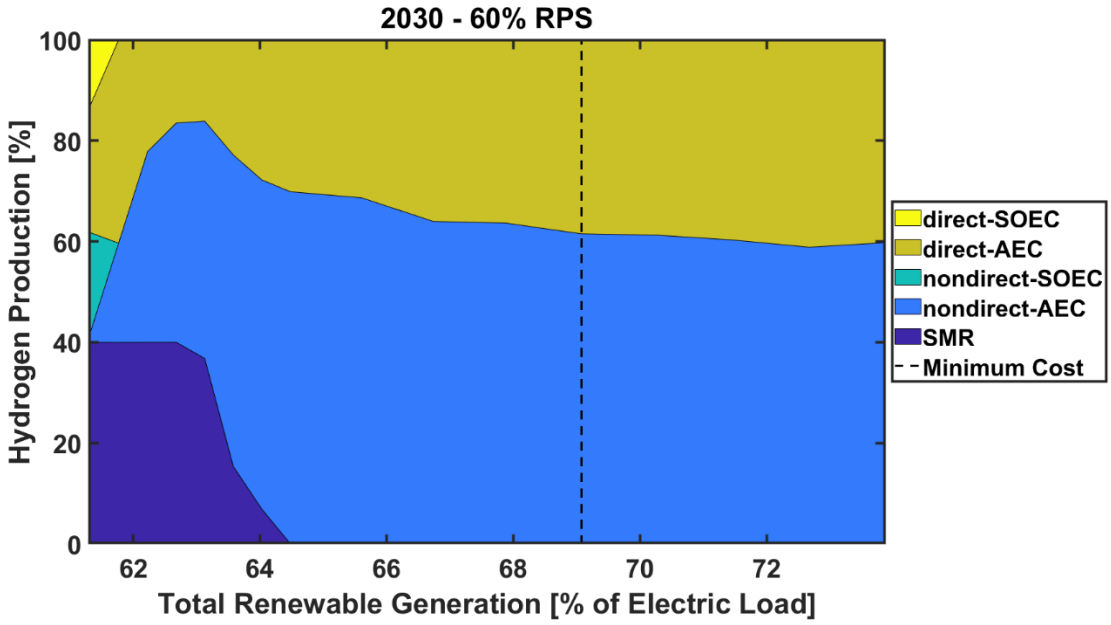

Figure 60: The technology portfolio for hydrogen production.

An example of the hourly operation of the electrolyzers in comparison to the availability of ERE and the electricity generation from NGPP can be seen in Figure 61. The top graph shows the electricity use of AEC, with a maximum capacity of 0.95 GWh. There is electricity used directly from ERE generation (labeled as Direct) and electricity from natural gas or stored electricity generation (labeled as Non-Direct). The Non-Direct label is due to the potential of the electrolyzers to take in renewable generation, using stored renewable electricity, or natural gas power plants. The bottom graph shows the electricity generation from NGPP, both NGPP-CC and NGPP-CT, stored electricity, such as from PHES, and the availability of ERE generation. Note the difference in capacity, the electricity use of AEC is approximately 3% of the capacity from the electricity generation technologies. The renewable electricity use matches the availability of ERE while the non-direct electricity use matches the electricity generation from NGPP and stored renewable electricity.

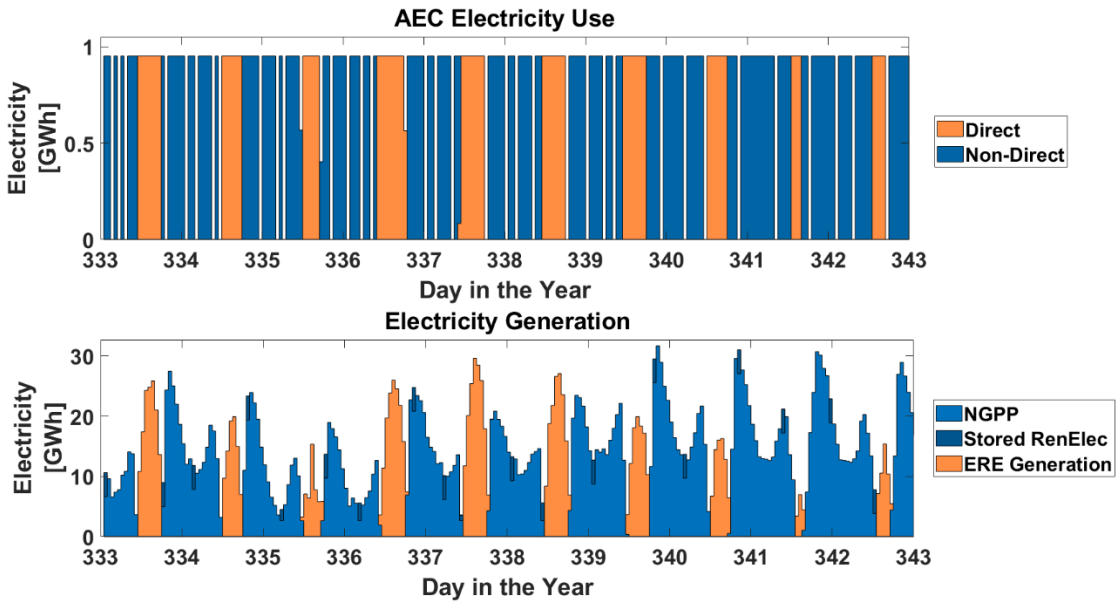

Figure 61: An example of the hourly directly renewable and non-directly renewable electricity use for AECs and the hourly electricity availability from ERE and NGPP generation.

7.3.3 2030 Technology Portfolio Mix Electricity Generation

Since the RPS goal is 60%, there can be use of fossil fuel natural gas power plants. This can be seen in Figure 62 which details the technology portfolio for the electric demand. In this case, a mixture of combustion turbines (CT) and combined cycle (CC) NGPPs were chosen due to the necessary operation of these NGPP-CT to act primarily as peaker power plants with frequent ramping to match the electric demand with renewable generation and NGPP-CC to act as load following, almost base load operation. A majority of the electric generation is from zero-carbon sources, wind and solar, hydropower and geothermal. However, when there is not enough renewable generation that can be used to directly meet the electric demand, energy storage is

required to ensure the 60% RPS. This can be seen at lower total renewable generation through the primary use of Li-Ion BES and PHES for electricity generation.

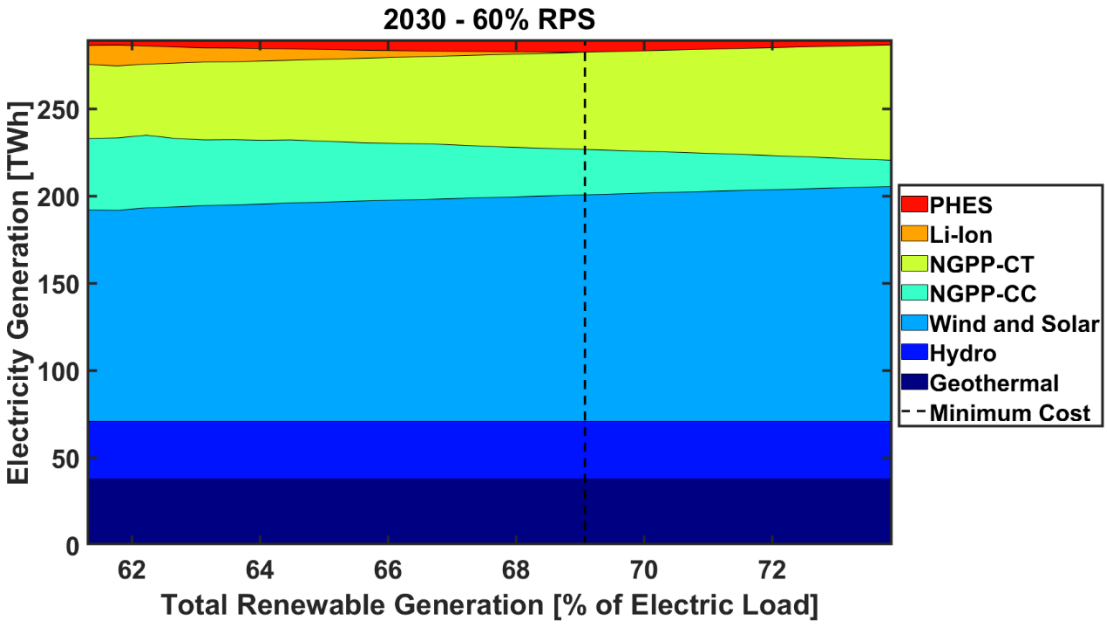

Figure 62: The portfolio of technologies which generate electricity to the electric load.

Some technologies add additional load to the electric demand that cannot be met directly with renewables, seen in Figure 63**Error! Reference source not found.**. A majority of the additional load is due to vehicles, primarily from BEV charging and electrolyzers which produce hydrogen for FCEVs. There is some additional load due to energy storage technologies, primarily at total renewable generation lower than 63.

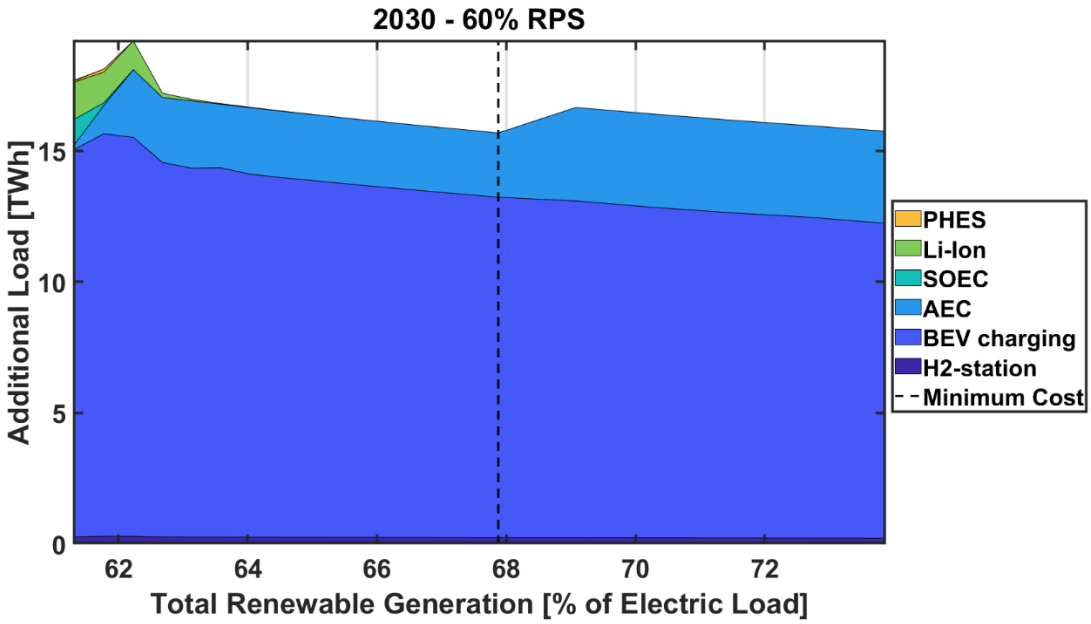

Figure 63: The portfolio of technologies that add additional demand to the electric load that cannot be directly met with renewable electricity.

A closer view of the energy storage technologies attributing to the additional load at lower renewable generation can be seen in Figure 64. It is important to note that overall, the relative amount of electricity used for these technologies is much less than 1% of the total electric demand. However, it is important to understand what is leading to the additional load from energy storage technologies. The charging of energy storage technologies is not limited to renewable generation. This is to allow for flexible operation of these energy storage technologies to charge from other sources, in this case from fossil fuel natural gas. This is the result of two main factors. First, there is a portion of the energy storage technologies that store ERE to ensure the 60% RPS constraint is met. Second, there are times when the energy storage technology stores fossil fuel natural gas electricity to reduce the overall system cost by reducing the natural gas power plant capacity.

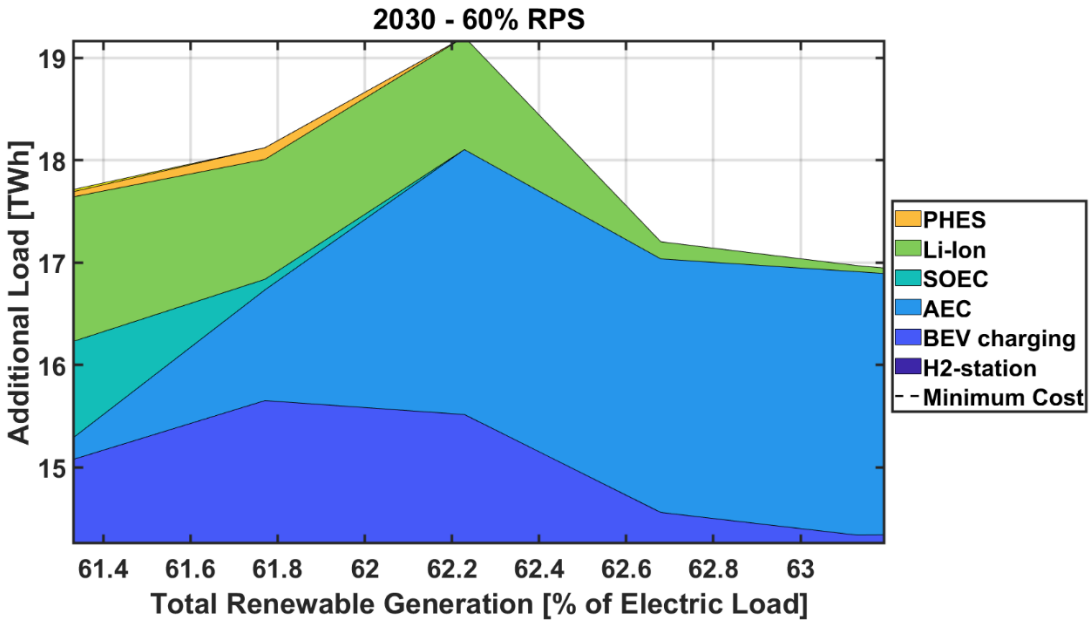

Figure 64: A close up look at the additional load technology, excluding BEV charging and H2-station electric demand, portfolio at lower renewable generation levels.

The hourly operation of the different technology types for the minimum total renewable generation case is shown in the following figures to further explain the optimization of natural gas power plant capacity with the use of energy storage. An example comparing the hourly operation of the Li-Ion BES and the NGPP-CT can be seen in Figure 65. The Li-Ion BES displays the discharge and charging. The charging is broken up into charging that can directly capture renewable electricity, displayed as RenCharge in the figure, and charging that does not directly capture renewable electricity and is primarily charged with fossil fuel natural gas, displayed as NonRenCharge in the figure. The discharge of the Li-Ion BES matches directly with the flat peaks of the NGPP-CT, which is the maximum capacity of the NGPP-CT. This shows that the Li-Ion BES is primarily used during the peaking electric demand which reduces the capacity of the NGPP-CT.

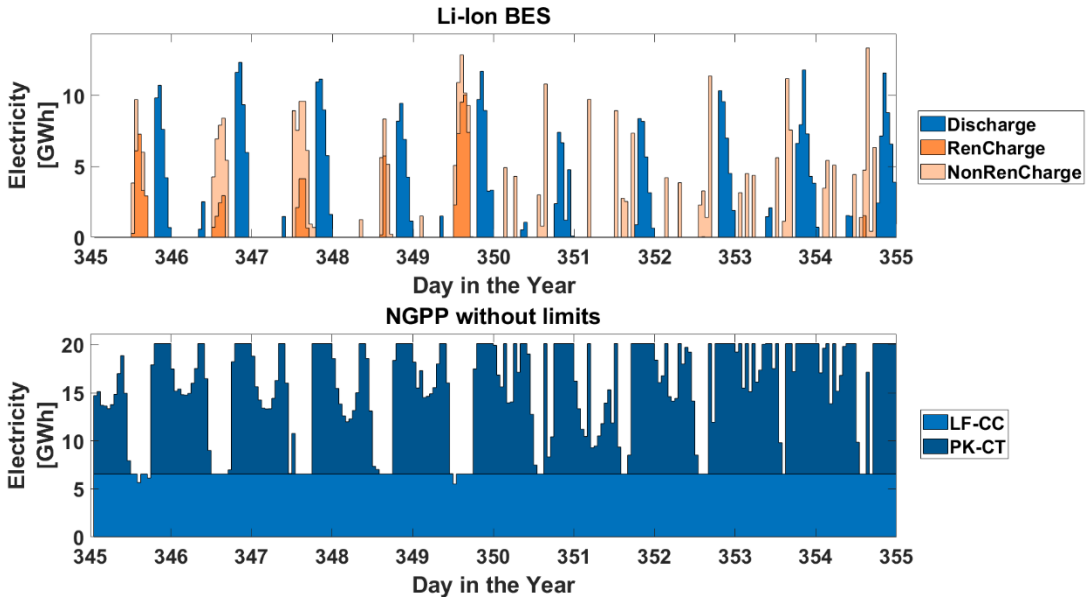

Figure 65: The hourly operation of Li-Ion BES as discharging and directly renewable (RenCharge) and non-directly renewable (NonRenCharge) charging in comparison of the NGPP-CT.

7.3.4 2030 Technology Portfolio Mix Electricity Dispatch Capacity

The technology portfolio for electricity dispatch capacity can be seen in Figure 66. The overall increasing total capacity is due to the increase of wind and solar. However, there is also a larger total capacity at lower renewable generation due to Li-Ion BES. This is like the 2045 scenario, the Li-Ion BES is highest in efficiency, but since the power and energy capacity are linked together the total Li-Ion BES capacity primarily reflects the energy storage required at lower renewable generation. Otherwise, at renewable generation greater than 61% the total capacity for all technologies, except solar and wind, remain constant. The main variations for dispatch capacity are from, Li-Ion, PHES, NGPP-CC, and NGPP-CT. The variation of energy storage technology capacity is similar to the variation seen in the use of ERE. The Li-Ion BES is present at

lower renewable generation, being completely replaced at around 69% renewable generation level. And the PHES is consistent in capacity across all renewable generation levels.

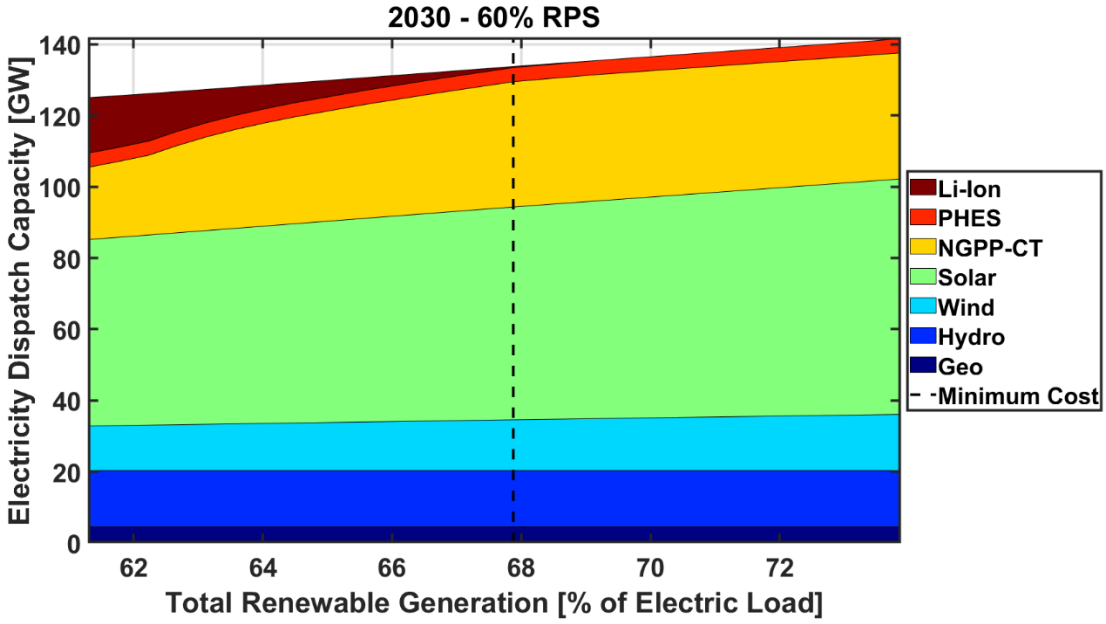

Figure 66: The distribution of installed capacity for technologies meeting the electric load demand

7.3.5 2030 Cost-Optimal Portfolio Mix Hourly Operation

At the cost-optimal case of 69% renewable generation, the only closed-form energy storage technology is PHES. There is no use of Li-Ion BES. Therefore, only the hourly state of charge for PHES is shown, amongst the closed-form energy storage technologies, as seen in Figure 67. The PHES is used for hourly charging and discharging. Since the RPS goal of 60% still allows for the use of fossil fuel natural gas power plants, there is not a significant need for seasonal storage. However, it should still be noted there is some short to medium duration storage towards the end of the year, which is more closely seen in Figure 68. The charge is held for slightly longer periods of time, as seen from days 336 to 357.

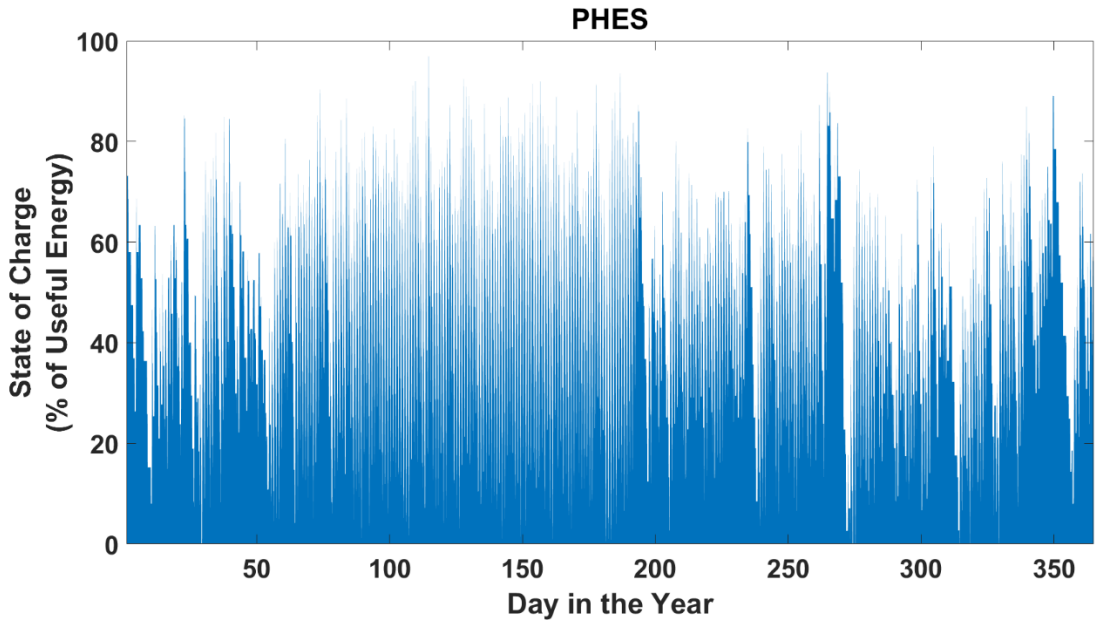

Figure 67: The hourly state of charge for PHES.

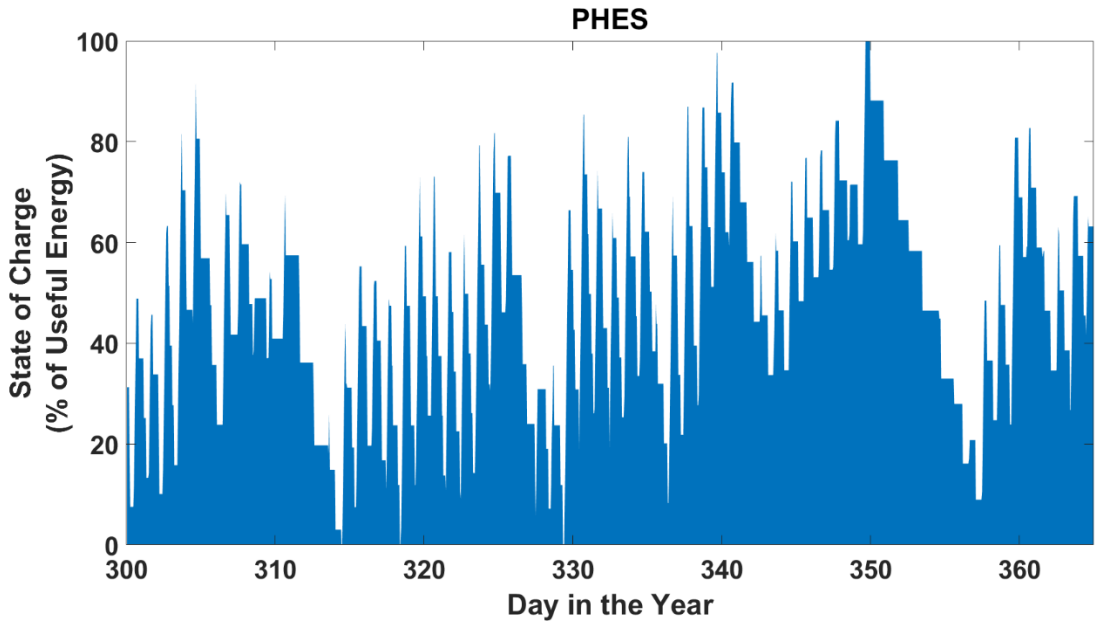

Figure 68: Closer look of the hourly state of charge for PHES, focusing on days 300 to 360.

The discharge of the PHES and the electricity production from NGPP-CC, and NGPP-CT can be seen in Figure 69. Each graph is scaled to the NGPP-CT, which has the highest capacity. This

figure shows how, although the PHES is charging and discharging quite frequently throughout the year, it is small as compared to the electricity production from either the NGPP-CC or NGPP-CT, noted by the scaled y-axis. The NGPP-CT produces electricity throughout the entire year, there is slightly less production during days 50-200 due to the most amount of renewable generation during this time. The NGPP-CC produces electricity consistently throughout the entire year. The time when the NGPP-CC is not operating matches with the renewable electricity generation.

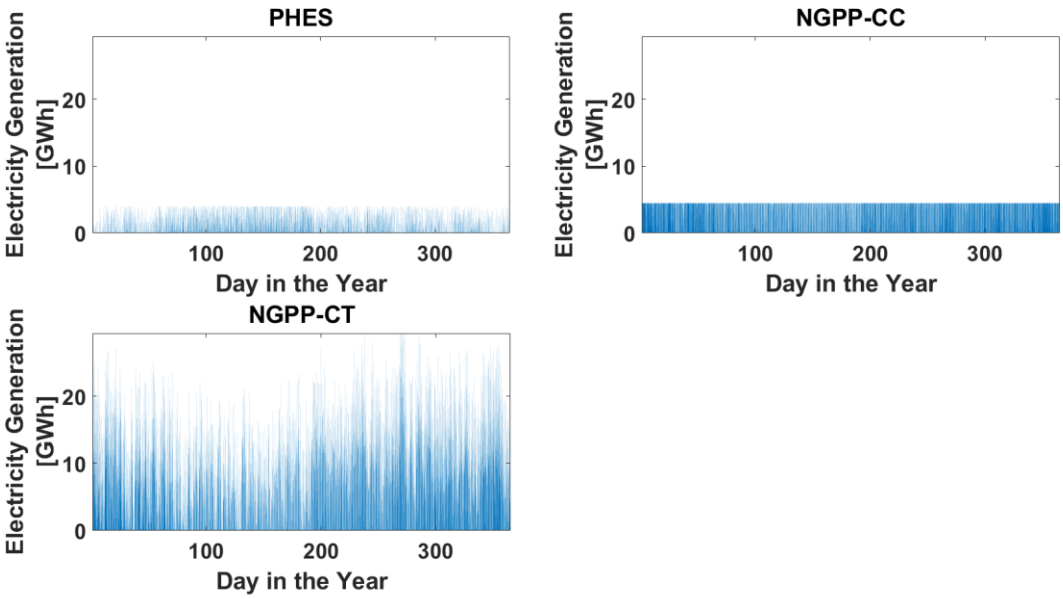

Figure 69: The hourly electricity generation of PHES and NGPP-CT.

An example hourly electrical generation delivered for all the different technology types for days 160 to 165 can be seen in Figure 70. There is little curtailment, and most of the electrical demand is met with renewable wind and solar, but there is a large portion of the electric demand that is met with NGPP. Although the NGPP are not clearly separated as NGPP-CC or NGPP-CT, refer to Figure 69 to see the differences in operation between the two NGPP types. There are small portions of the electric demand that is met with energy storage, which in this case is only

PHES. Hydro power and geothermal power act as baseload throughout the entire year, as the capacity for both does not exceed the electric demand and geothermal has severe ramping limitations that require it to run as baseload generation.

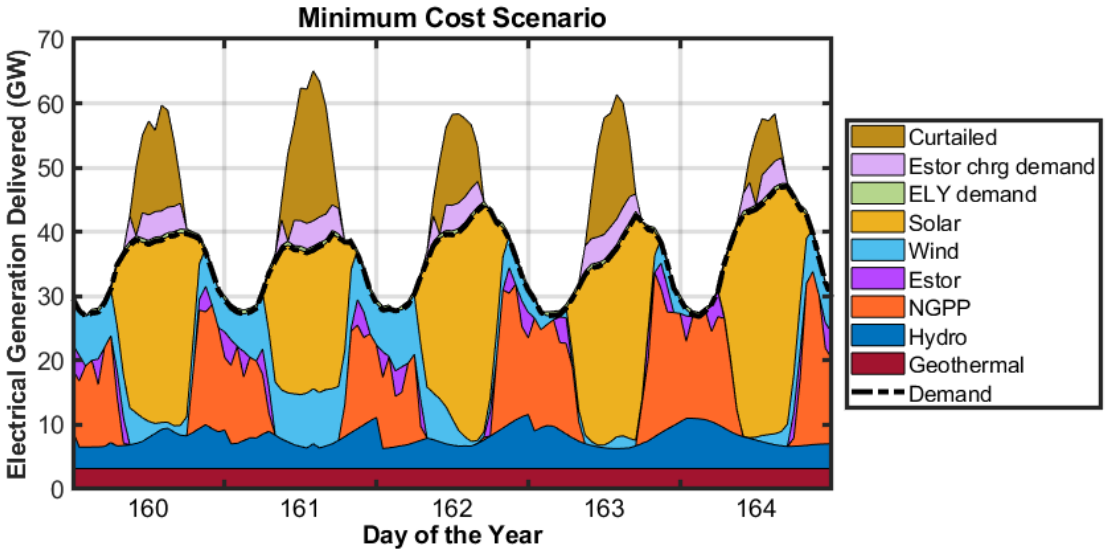

Figure 70: The hourly operation of charging and discharging energy storage technologies, electrolyzers, solar, wind, hydropower, and geothermal relative to the demand and curtailment during days 160 to 165.

7.4 2045 Cost of Carbon Influence

The previous results are constrained to meet California's 2045 zero-carbon electric grid. However, if left to optimize the electric grid without such a constraint, the use of natural gas power plants is lower cost than energy storage technologies and the main optimal electricity generating source. An analysis considering the reduction of carbon as the main objective constraint, using a cost of carbon, was considered to determine the optimal technology portfolios. There are different types of cost of carbon such as a social cost, detailed in section 2.6.5. However, these costs range well below \$500/tonne CO_2, which is less than the cost to reduce carbon emissions in the electricity sector as discussed in section 10.1. Therefore, an

analysis spanning the cost of carbon as an optimization driver in the objective function was conducted. The analysis was considered using the optimal renewable generation scenario from the base case scenario. The optimal case for the base case scenario which resulted in a 48% curtailment level has ample availability of renewable generation to be used for non-electric natural gas use. The purpose of this analysis is to determine how the renewable generation will be used in for the electric grid as compared to non-electrical demands, when considering an objective focused on carbon reduction. The results are plotted based on the cost of carbon, which is spanned from \$0/tonne CO_2 to \$5000/tonne CO_2.

7.4.1 Cost of Carbon Influence - Total System Cost

Unlike the previous results, the purpose of this analysis is not to find a minimum TSC as the TSC increases with increasing cost of carbon, as shown in Figure 71. The amount of renewable generation was set to that of the 48% curtailment lowest cost case from the 2045 Base Case scenario. The TSC increases slightly from \$0/tonne CO_2 to \$100/tonne CO_2, from \$1.6 trillion to \$1.7 trillion. This represents that there only is a slight change in technology portfolio. However, the TSC remains relatively constant from \$100/tonne CO_2 until \$500/tonne CO_2, which represents little to no change in the technology portfolio. Past the \$500 tonne CO_2, the TSC continues to increase representing a large shift in technology portfolio. The main cause for this shift is the use of renewable generation to produce renewable gas to offset fossil fuel natural gas. The TSC increases to more than \$2 trillion at \$1,000 tonne CO_2, which is less than a 20% increase in cost, but has a significant increase in ERE use. The specific technology portfolios are further explained in the following section.

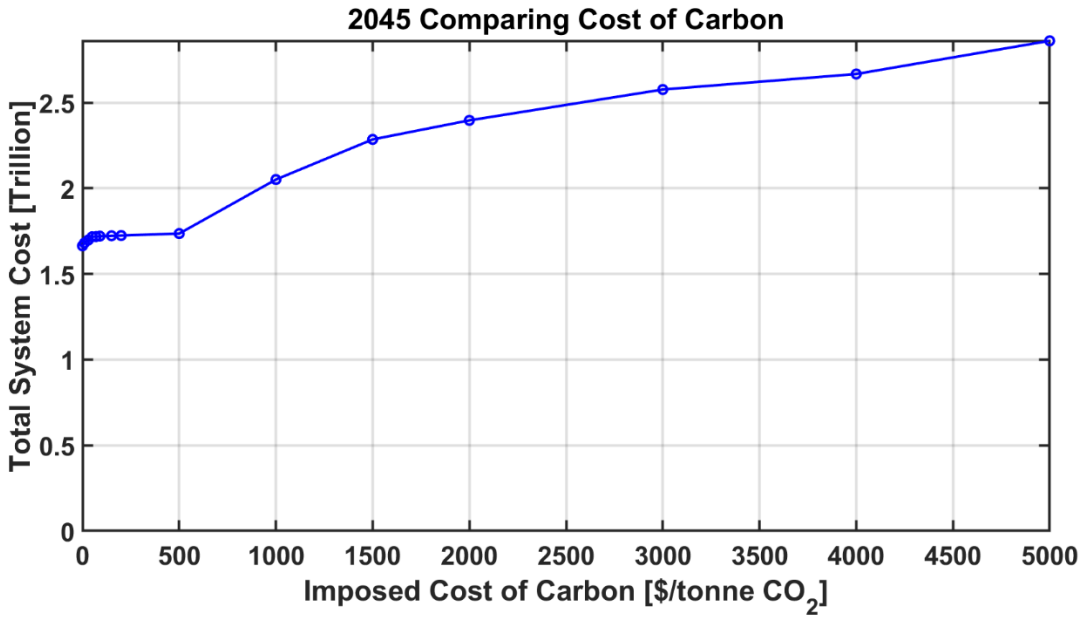

Figure 71: The total system cost with increasing cost of carbon.

7.4.2 Cost of Carbon Influence - Technology Portfolio Mix

The total amount of ERE is constant with each imposed cost of carbon as there isn't a change in installed renewable capacity unlike previous results, seen in Figure 72. The amount of curtailed ERE is high at lower costs of carbon but decreases as portions of ERE is used for energy storage, Li-Ion BES and PHES, and electrolyzers, SOEC and AEC, at higher costs of carbon. At \$0/tonne CO_2, the main use of ERE is for Other and AEC. The "Other" represents direct use of ERE for non-energy storage or hydrogen production such as vehicle charging or electric demand for hydrogen stations. The AEC use is due to the hydrogen production required for FCEVs. This \$0/tonne CO_2 case also represents the minimum TSC, the case where there is no energy storage and the ERE is used for necessary demand. As the cost of carbon increases, there is a larger portion of ERE used in energy storage technologies, such as Li-Ion BES and PHES, and hydrogen

production, such as SOEC and AEC. Most of the ERE use is for hydrogen production, seen by the large makeup of ERE use from AEC and SOEC. At lower costs of carbon, the main hydrogen production technology is AEC. However, as the cost of carbon increases, the general shift of technologies is to more efficient technologies. Therefore, SOECs start producing hydrogen at \$1000/tonne CO_2. What this represents is the incentive to reduce carbon, when the cost of carbon is high enough to incentivize hydrogen production by selecting the more efficient SOEC which can produce more hydrogen from the same amount of ERE as opposed to the lower cost and lower efficient AEC. This is also seen through the increased portion of ERE use for Li-Ion BES. The Li-Ion BES is the most efficient energy storage technology. As the cost of carbon becomes higher than \$1000/tonne CO_2 there is a clear shift to more efficient technologies to better utilize ERE as the curtailment decreases.

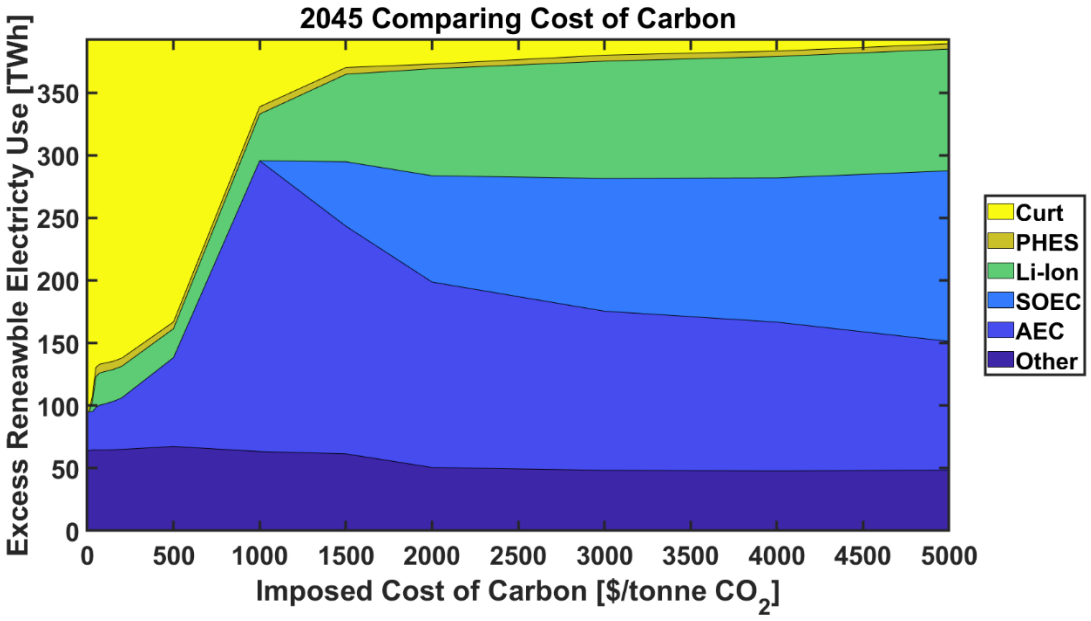

Figure 72: The technology portfolio which uses ERE with each imposed cost of carbon.

The electricity generation technology portfolio can be seen in Figure 73. At lower costs of carbon, less than \$50/tonne CO_2, there is little to no energy storage technologies. The dispatchable electricity generation, that is the electricity generation that cannot be met directly with renewable wind & solar, hydro, or geothermal, is primarily composed of natural gas power plants. A closer look of the dispatchable technologies can be seen in Figure 74. From \$0/tonne CO_2 to \$50/tonne CO_2 the primary dispatchable electricity generation technology are NGPPs. The NGPP-CC is more preferred over the NGPP-CT, as NGPP-CC are more efficient and therefore have less carbon emissions than NGPP-CT. Once the cost of carbon is greater than \$50/tonne CO_2 there is an incentive to invest in energy storage technologies to offset carbon as opposed to curtailing the ERE. At \$50/tonne CO_2 there is an almost equal generation from Li-Ion BES and NGPP-CC. Starting at \$150/tonne CO_2 to \$500/tonne CO_2 there is an increase in FC electricity generation, which can also be seen in Figure 75, which displays the percent of hydrogen used for FCs.

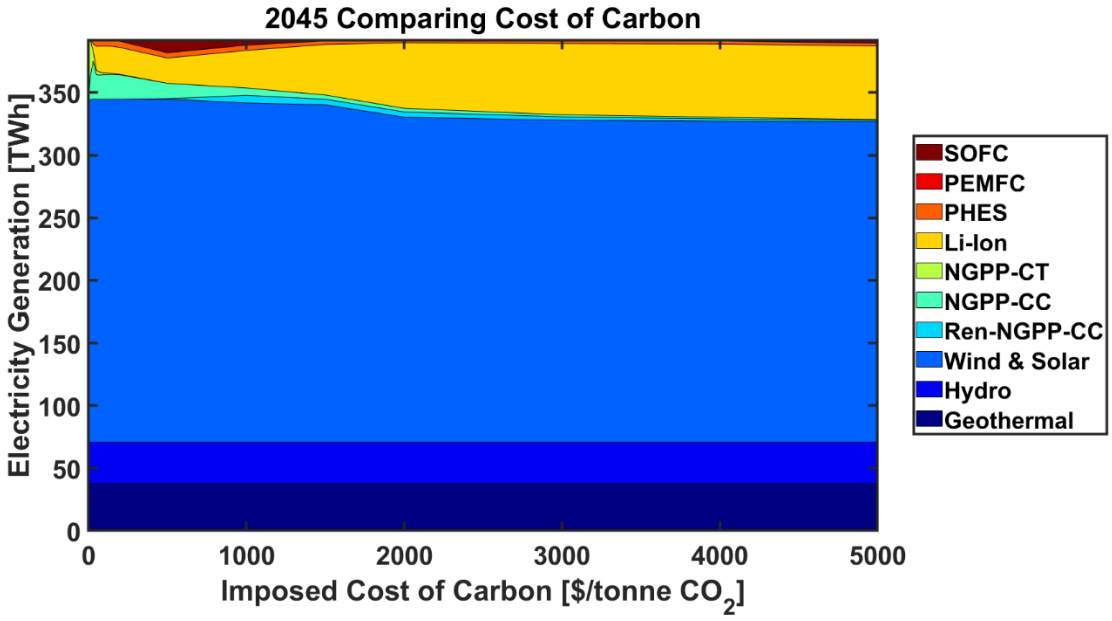

Figure 73: The electricity generation technology portfolio at each imposed cost of carbon.

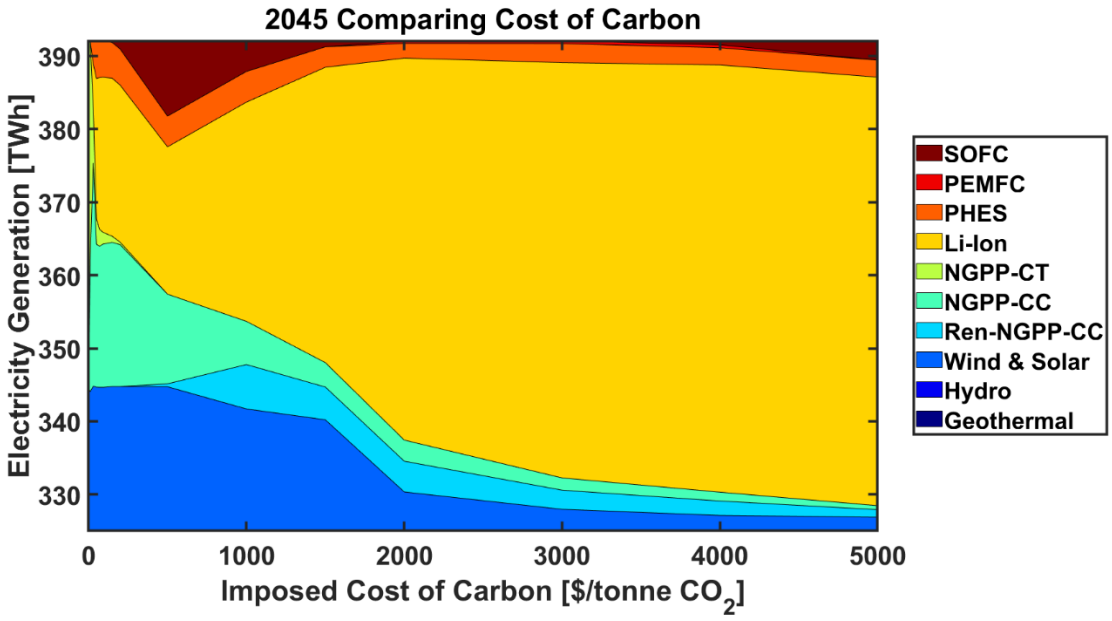

Figure 74: A zoomed in view of the dispatchable technologies, which are displayed at the top of Figure 73.

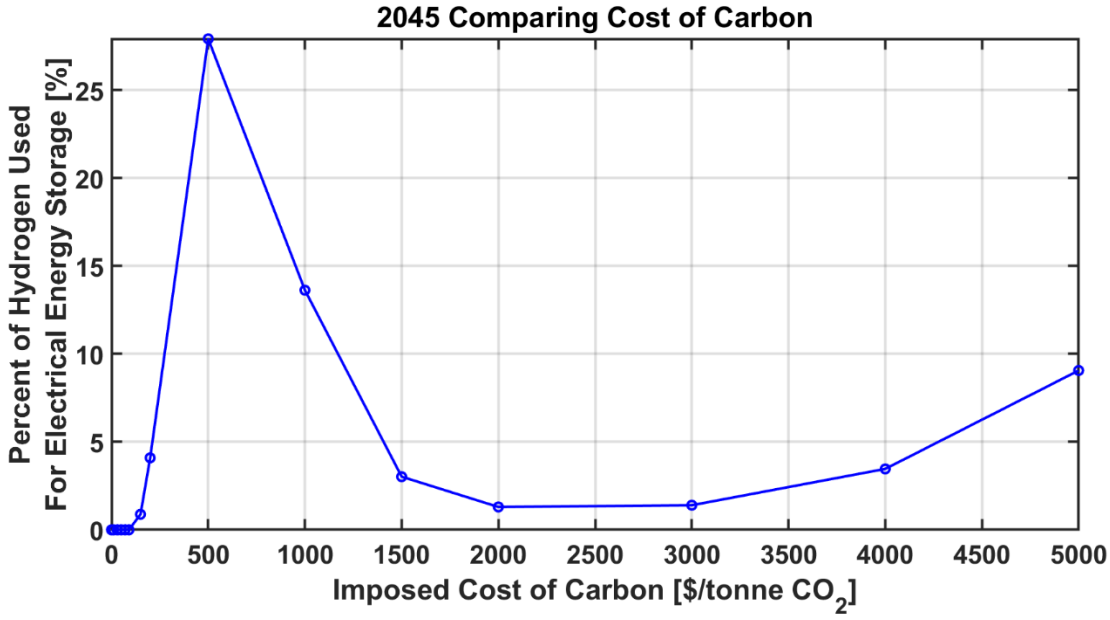

Figure 75: The percent of hydrogen production used for fuel cells.

The technology portfolio presented at \$500/tonne CO_2 is the closest in representing the optimal technology portfolio for the 2045 renewable gas for NGPP scenario, almost the entire

electric grid demand is met with zero carbon electricity. Only 3% of the electricity generation is met with fossil fuel NGPP-CC. The fossil fuel electricity generation further decreases at carbon costs higher than \$500/tonne CO_2 with an increasing portion of the NGPP-CC electricity generation fueled with renewable gas. The transition from \$500/tonne CO_2 to \$1000/tonne CO_2 sees an increase in Li-Ion BES electricity generation and ERE use which replaces SOFCs, however there is a significant use of ERE increase in electrolyzers. The hydrogen produced from the electrolyzers are not primarily used for FCs, but rather for renewable gas.

Figure 76 displays the distribution of gas, either renewable or fossil fuel, that meets the non-electric gas demand. The maximum mix of hydrogen with renewable methane is assumed to be 10% by volume, which equates to around 2% by energy content, as seen by the relatively flat mix of renewable hydrogen past \$500/tonne CO_2. Hydrogen is first introduced and saturated into the non-electric natural gas demand at \$500/tonne CO_2. Then, as the cost or carbon increases, the production of renewable methane offsets the fossil fuel natural gas demand. This causes the increased ERE use for electrolyzers at carbon costs greater than \$1000/tonne CO_2. However, even as the cost of carbon increases, the penetration of renewable gas into the non-electric natural gas demand increases only slightly, with a maximum of 63% renewable gas at \$5000/tonne CO_2. Compared to the 40% renewable gas at \$1000/tonne CO_2 or 52% renewable gas at \$1500/tonne CO_2, the increase of percent renewable gas with the increase in carbon cost is very minimal. This is due to the limitation of ERE availability to produce the renewable gas, seen by the decrease of curtailment in Figure 72. This shows that to reduce our dependence on fossil fuels to reduce carbon emissions more renewable generation is needed.

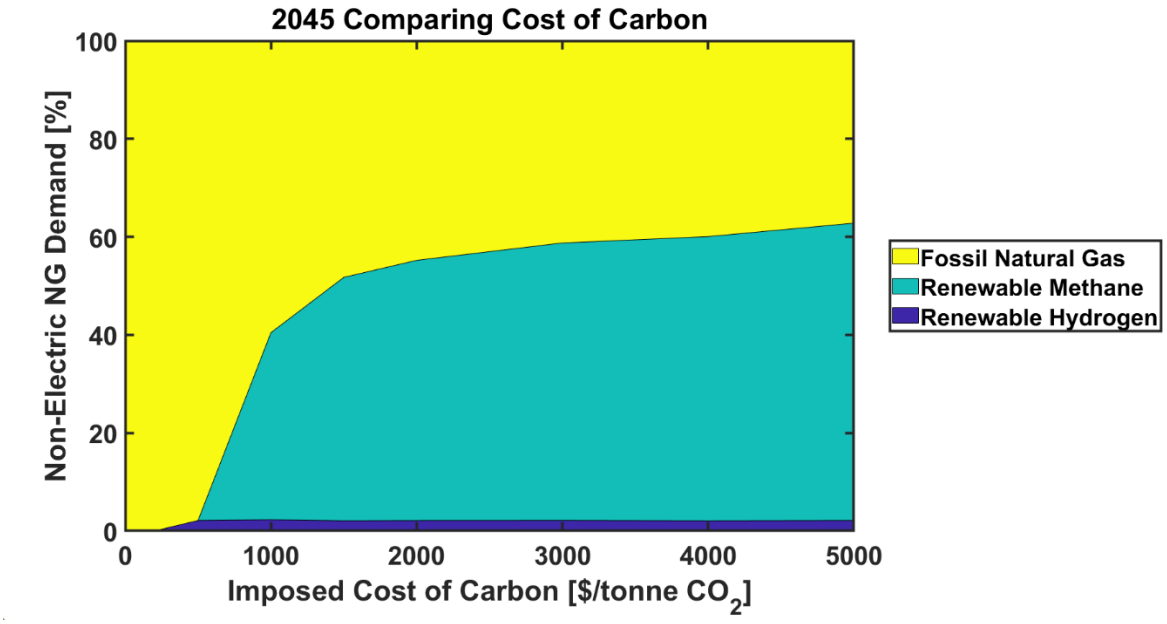

Figure 76: The distribution of non-electric natural gas demand that's met by either fossil fuel natural gas, renewable methane, or renewable hydrogen.

Although not considered in this analysis, portions of fossil fuel demand can be met with biomass. Biomass can be used to offset the fossil fuel use, however there is limited availability [168], [298]. California is estimated to have about 1,100 thousand tonnes of renewable methane per year, which amounts to approximately 8% of the non-electric NG demand [299]. Currently, less than 6TWh of electricity generation, or less than 2% of the 2045 electric demand, comes from biomass [300]. The limited availability of biomass is better suited for direct use in transportation as opposed to produce electricity, the future electric grid will be highly integrated with renewable resources and natural gas generally burns cleaner and more efficient than transportation fuels [301]. The purpose of this study is to consider the interactions of the electric grid and therefore biofuels and biogas are not included in this study. There are also other sectors that were not considered, for example fuels for other transportation such as aviation or freight

rail. These other sectors will most likely have a larger need for direct biofuel use as biofuels are more energy dense than hydrogen.

7.4.3 Cost of Carbon Influence – $500/tonne CO_2 Portfolio Mix Hourly Operation

Figure 77 shows how the electricity generating and ERE consuming technologies operate relative to one another. This figure is similar to those presented in the Base Case, with a direct comparison with Figure 38, except for the addition of natural gas power plants. As this analysis allowed for the use of fossil fuel NGPP, this section will focus on the operation of the NGPP, as the operation of the various other technologies are relatively the same. The NGPP are seen to be operating during times of low renewable generation and offset the generation that would otherwise be met with energy storage and fuel cell technologies. This shows that there is an optimal mix of utilizing the NGPPs to generate electricity to better optimize the installation of fuel cell and energy storage technologies.

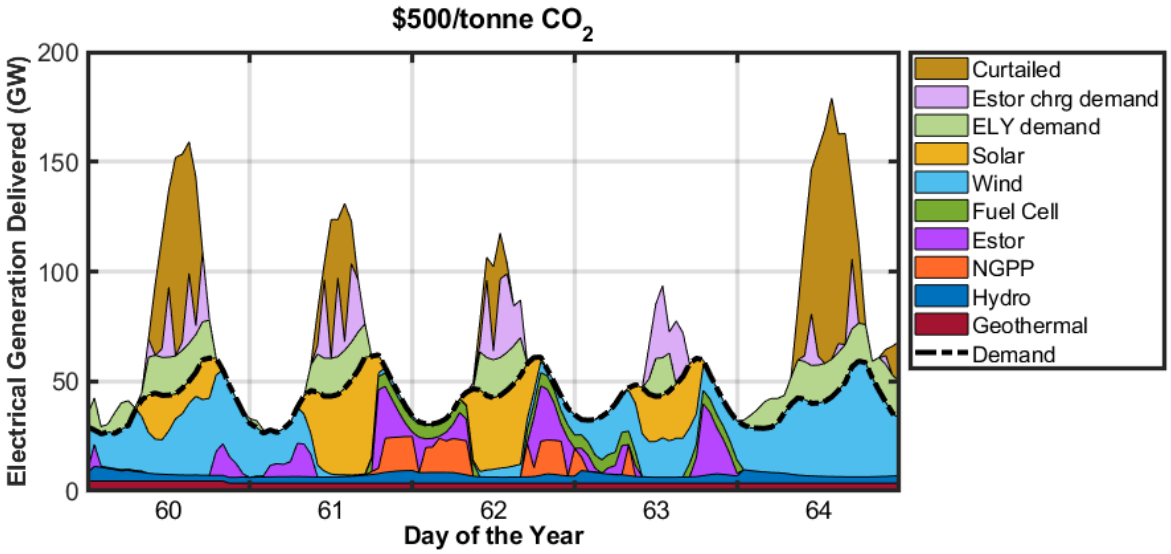

Figure 77: The hourly operation of charging and discharging energy storage technologies, electrolyzers, solar, wind, fuel cells, natural gas power plants, hydropower, and geothermal relative to the demand and curtailment during days 60 to 65.

8 TASK 5 – Evaluate various scenarios for the optimized portfolio of technologies

8.1 Shadow Price

The Shadow Price is used to consider which parameters and constraints will have the largest influence on the optimization results, also known as the lambda or the Lagragian multiplier [302], [303]. The Shadow Price represents the sensitivity of the constraints on reaching the optimum solution. The Shadow Price represents how much the objective value changes with each unit of the constraint. If the Shadow Price is negative it represents that a unit increase in the constraint will result in a decrease of the objective value by the Shadow Price, vice versa for a positive Shadow Price. If the Shadow Price is 0 there is no correlation between the constraint and the objective value. In other words, the Shadow Price is the gradient, or slope, of the variable's effect on the objective value. For example: if the constraint has a positive Shadow Price it means that a higher variable value would equal to a higher objective value, the Shadow Price also determines how much the objective function would rise with each variable unit increase. Also, this would mean that if the constraint were smaller then the objective function would be lower. This evaluation will focus on the 2045 base scenario. The purpose of looking at the analysis is to order the technologies on highest Shadow Price, having the largest effect on the objective function, to lowest Shadow Price, having the smallest effect on the objective.

The relevant constraints are listed from highest to lowest shadow price in Table 22. The constraints are those that are directly connected to economic costs, such as capacity and

operation which relate to instant cost and O&M costs, respectively. Constraints that are not based on economic inputs (such as maximum capacity for PHES or operational constraints) are not shown in the table. The Shadow Price shown is the maximum shadow price found for that technology, therefore repeats of different Shadow Prices for the same technology are not shown.

The Shadow Prices were found by searching through the lambda from highest to lowest Shadow Price. It is infeasible to look through all the Shadow Prices so only the top 20 Shadow Prices were taken. The AEC and Li-Ion BES did not show up when spanning through the Shadow Prices. This means that the Shadow Price for these technologies are lower than the shown Shadow Prices for the previous technologies, therefore the exact Shadow Price is undetermined. Therefore, the order for AEC and Li-Ion BES are not ordered by Shadow Price.

Table 22: Table of Shadow price and the related constraints.

Considered Technology	**Constraint**	**Shadow Price**
PAFC	Capacity and Operation	8.86e+04
MCFC	Capacity and Operation	6.38e+04
CAES	Capacity and Operation	3.59e+04
SOEC	Capacity and Operation	3.13e+04
PEMFC	Capacity and Operation	7.73e+03
PEMEC	Capacity and Operation	7.63e+03
ZnBr BES	Capacity and Operation	6.23e+03
PHES	Capacity and Operation	3.03e+03
SOFC	Capacity and Operation	2.93e+03

AEC	Capacity and Operation	Undetermined
Li-Ion BES	Capacity and Operation	Undetermined

8.2 Sensitivity Analysis – 2045 Costs

A sensitivity analysis was conducted for the optimal 2045 Base Case result by running the optimization assuming a change in the technology costs of a single technology. Both a reduction and increase in costs, spanning from 20% to 200% of the original technology cost, were assumed to determine how it changes the results, with 100% resulting in the same economic assumption as the previous 2045 Base Case results. The cases considered are represented in Table 23. Each case only considers the change of one single technology's costs. The purpose of this analysis is to determine the sensitivity of the results due to costs and the main comparisons are not only between the different technologies for each end-use, such as Li-Ion compared with PHES, ZnBr, and CAES, but also for the difference in technology selection between different end-uses, such as AEC compared with PHES.

The factor used to compare the different scenarios is the annual cost. The annual cost is the optimization objective function value, which relates to the operational and technology costs for one year. The change in annual cost is shown in Figure 78 to Figure 79, all figures show the same data but from a different angle as the figure is a three-dimensional plot. The technology axis represents the technology that is singled out to change in technology cost, the relative change in technology cost is represented by the percent of the original technology cost, with 100% being the technology cost assumed for the 2045 Base Case, therefore there is no change across all technologies at 100% of original technology cost.

This sensitivity analysis shows how significant of an effect the technologies have on the total cost. For example, the cost of Li-Ion BES has a large effect on the costs, seen by both the positive and negative heights of the bar graph for Li-Ion. If Li-Ion BES were 20% of the original costs, there would a $4.8 billion decrease in annual cost. With each percent less than 100% of the technology cost, there results in a decrease in annual cost, more clearly seen in Figure 79. This is also true for AEC and SOFC. These technologies are the three with the lowest Shadow Price. These technologies most effect the annual cost when varying its own technology cost. The Shadow Price was determined based on the original technology cost. Since these Shadow Prices were the lowest as compared to the other technologies, any costs lower than the original technology cost would result in a decrease in annual cost and any costs higher than the original technology cost would result in an increase in annual cost.

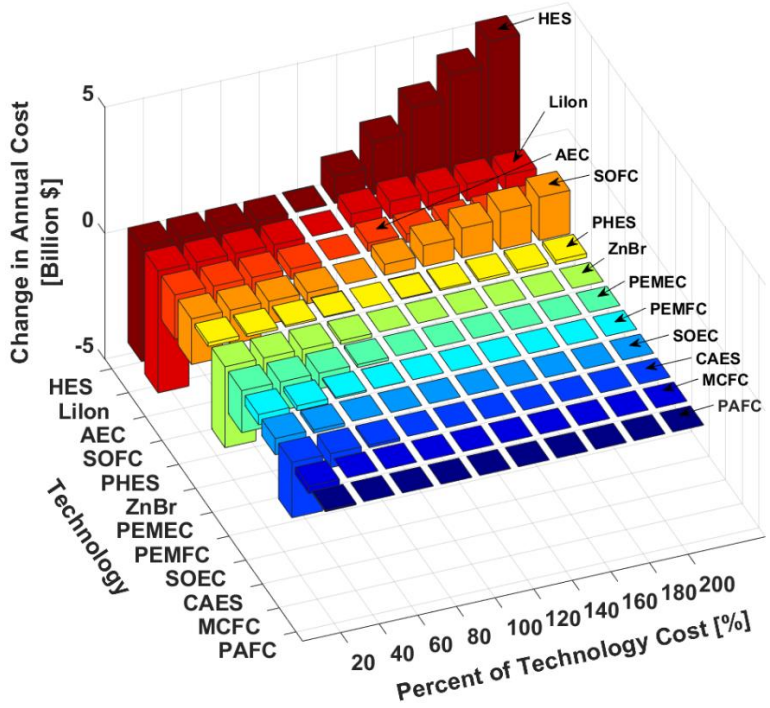

Figure 78: A three-dimensional representation of the change in annual cost with the different economic assumptions of each of the technologies listed.

Table 23: A table representing each of the cases that result in the three-dimensional plots presented in this sensitivity analysis. The percentage represents the percentage of the original technology cost, the technology listed is the single technology that has its costs changed.

	Single Technology Cost Changed											
	PAFC	**MCFC**	**CAES**	**SOEC**	**PEMFC**	**PEMEC**	**ZnBr BES**	**PHES**	**SOFC**	**AEC**	**LiIon BES**	**HES**
Percent of Original Technology Cost	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%
	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%
	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	120%	120%	120%	120%	120%	120%	120%	120%	120%	120%	120%	120%
	140%	140%	140%	140%	140%	140%	140%	140%	140%	140%	140%	140%
	160%	160%	160%	160%	160%	160%	160%	160%	160%	160%	160%	160%
	180%	180%	180%	180%	180%	180%	180%	180%	180%	180%	180%	180%
	200%	200%	200%	200%	200%	200%	200%	200%	200%	200%	200%	200%

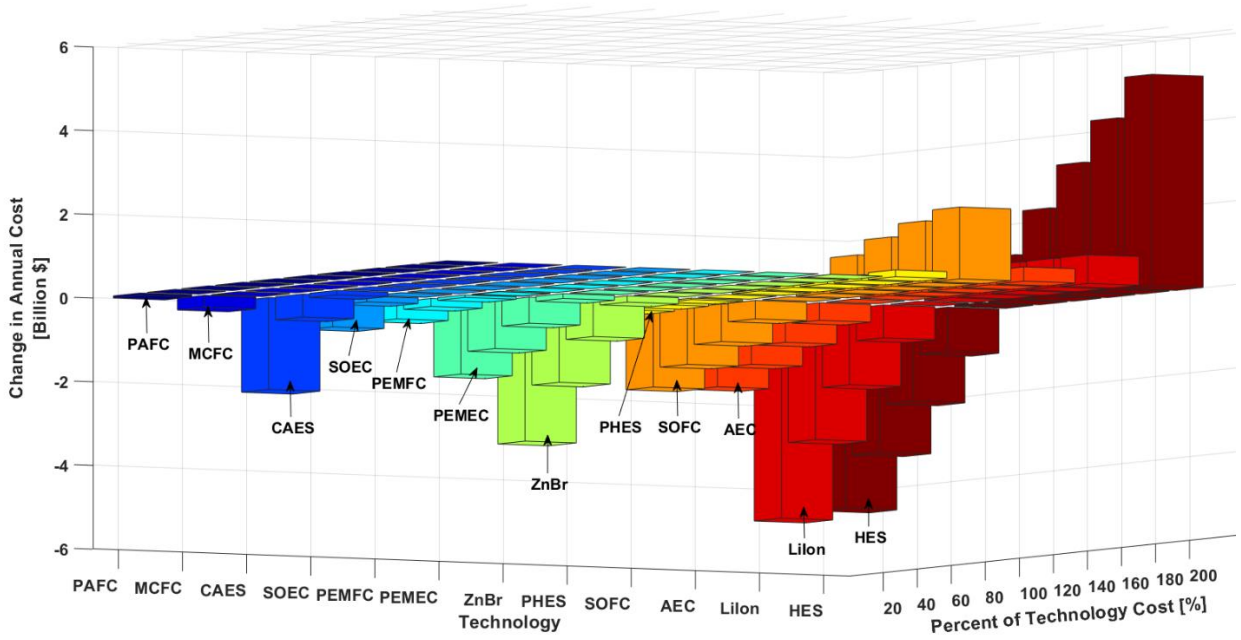

Figure 79: An underside view of the three-dimensional representation of the change in annual cost with the different economic assumptions of each of the technologies listed.

All other technologies only see a decrease in annual cost at technology costs lower than the original technology cost. This means that these technologies are either not selected, or only makeup a small portion of the technology portfolio, in the 2045 Base Case scenario. Some technologies have a greater change in annual cost with a decrease in technology cost, as seen by the $2.2 billion decrease in annual cost at 20% of original technology cost for CAES. This represents the sensitivity of the technology on costs as compared to its alternative options, such as other energy storage technologies with CAES. However, there are some other technologies that change very little, such as PAFC. There is little change even with a technology cost 20% of the original. This represents that the PAFC technology is not competitive with other technologies, even with such a significant decrease in cost which means the other fuel cell technologies are just more competitive and preferred.

With the changes in the technology costs, there is also a change in technology portfolio. Most apparent is an increase in the technologies that result in a lower annual cost. However, this will offset the use of other technologies. The relevant technology portfolios that utilize ERE are shown in Figure 80. Not all the technology cases are shown, as some have none to little change in the ERE use. There are three general trends seen here. First, at lower costs than the original, the considered technology takes up a larger portion of the ERE, as seen specifically by the CAES case. Second, at costs higher than the original the considered technology either takes up less portion of the ERE or is replaced with another technology, as seen by the AEC case. Third, although the technology does not directly capture ERE, such as PEMFC and SOFC, it directly effects the hydrogen produced. More clearly seen in the SOFC case, the use of AEC decreases at costs greater than the original and replaced with Li-Ion BES. In this case, the overall ERE use decreases as well. This is due to the Li-Ion BES being more efficient than the AEC to store electricity, which requires less ERE.

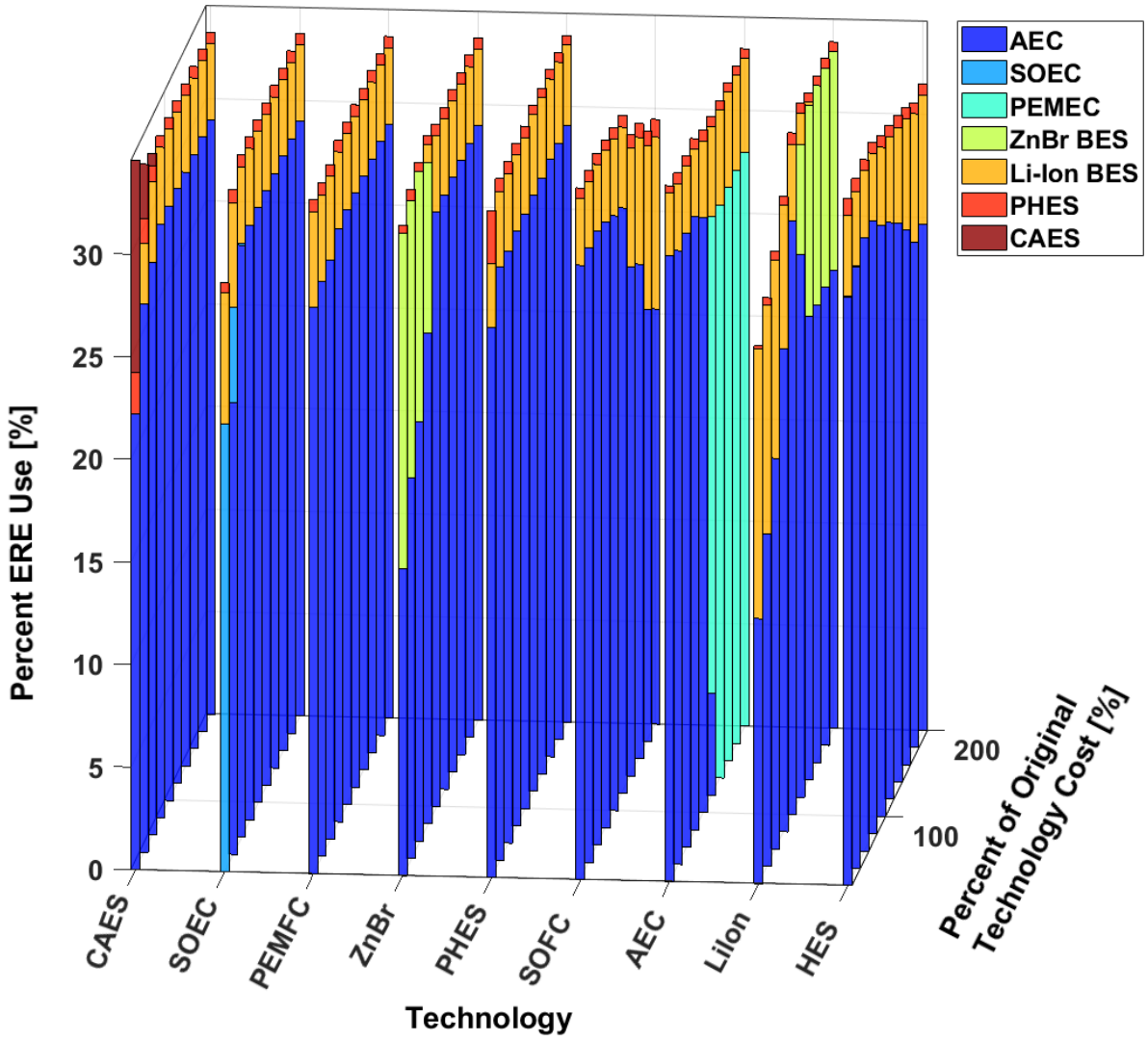

Figure 80: The technology portfolio that utilizes ERE, each bar represents a single scenario.

There is also changes in the electricity generation, as seen by the SOFC case with a decrease in hydrogen production and a higher reliance on Li-Ion BES. This can be further seen in Figure 81 which displays the technology portfolio for electricity generation. As previously noted, the PAFC has a very insignificant change despite a technology cost 20% of the original. Even at slightly higher percentages, such as 40% of the original there is no selection of PAFC. In

comparison, the MCFC has a significant increase in technology portfolio mix at 20% of the original technology cost. However, once the technology cost increases to 40% of the original cost, the selection mix significantly decreases. This is also seen by the PEMFC technology. The main fuel cell technology selected is the SOFC. In the case where the SOFC increase in cost there is a reduction of hydrogen production for energy storage, an increase dependence on Li-Ion BES for energy storage, and a slight increase in PEMFC selection. This means that PEMFC is the second choice for fuel cell technology after the SOFC.

CAES is like the fuel cell technologies, with a significant technology selection at lower technology costs, however instead of replacing the generation from fuel cells, primarily replacing Li-Ion generation. This represents the need for long duration and shorter duration storage. The CAES, despite a 20% decrease in original technology cost, is still not cost effective to use for long duration storage, as seen by the still significant technology portfolio mix of the SOFC. On the other hand, both ZnBr and Li-Ion BES, at lower technology costs, replace the technology portfolio mix that was otherwise satisfied with SOFCs. This represents the ability for ZnBr and Li-Ion BES to fulfill long duration storage. However, there is still portfolio mix of SOFC which represents that even at 20% of the original technology cost for the energy storage technologies hydrogen and fuel cells are better able to fulfill long duration storage. The Li-Ion BES is replaced by ZnBr at higher technology costs for the Li-Ion BES cases. This represents that ZnBr is the preferred energy storage technology second to Li-Ion BES, similar to how PEMFC is second choice to SOFC.

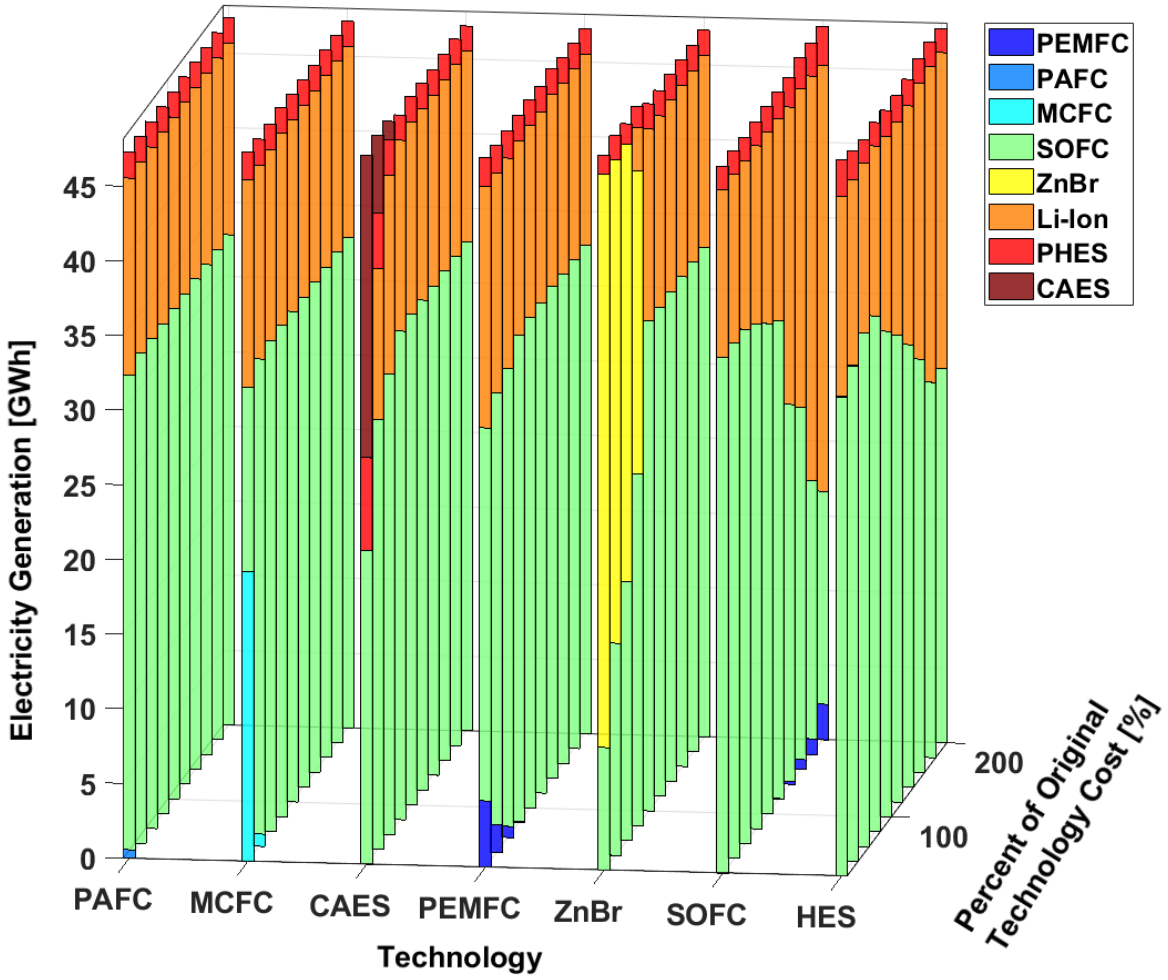

Figure 81: The technology portfolio that generates electricity, each bar represents a single case.

8.3 Sensitivity Analysis – 2045 Efficiency

A similar sensitivity analysis with costs was conducted with efficiency. However, the HES case was not considered as the efficiency for storage was not considered. Only 5 cases of varying efficiency were considered. And, as the efficiency cannot realistically be greater than 100% or lower than 0% and the efficiency of each technology differs, the efficiency between the original efficiency and the tail ends (0% or 100%) was considered. In other words, the original efficiency

is set at 100%. Any efficiency difference percent below 100% is the percent between 0% efficiency to the original efficiency. Any efficiency difference percent above 100% is the percent difference subtracted from 100% of the original efficiency. An example with original efficiency of 60% is detailed in Table 24. This ensures that the efficiency does not exceed 100%.

Table 24: Table of how the percent efficiency difference correlates to the considered efficiency.

Efficiency Difference [%]	**Efficiency [%]**
50%	40%
100%	60%*
150%	80%

*original efficiency

Figure 82 and Figure 83 are different viewpoints of the same three dimensional plot which shows the change in annual costs by the varying assumptions of efficiency. The only technologies that have an effect on the annual costs are: Li-Ion BES, AEC, SOEC, PHES, ZnBr BES, PEMEC, and PEMFC. The costs increase if there is a decrease in efficiency for Li-Ion BES, AEC, SOFC, and PHES. This is due to the selection of these technologies in the original run and a decrease in efficiency would result in either a change in technology choice or an increase in necessary capacity for the same energy content. For all technologies that effect annual cost, an increase in efficiency result in a decrease in annual cost. This represents the increase in efficiency for these technologies exceeds the efficiencies than their counterparts. This is further detailed in Figure 84 and Figure 85.

Table 25: A table representing each of the cases that result in the three-dimensional plots presented in this sensitivity analysis. The percentage represents assumed efficiency for that technology.

	Single Technology Cost Changed										
	PAFC	**MCFC**	**CAES**	**SOEC**	**PEMFC**	**PEMEC**	**ZnBr BES**	**PHES**	**SOFC**	**AEC**	**LiIon BES**
Efficiency	22.5%	30%	26%	41%	28%	32%	32%	40%	36%	32%	42%
	45%	60%	52%	81%	55%	65%	65%	80%	72%	65%	85%
	72.5%	80%	76%	91%	78%	82%	82%	90%	86%	82%	93%

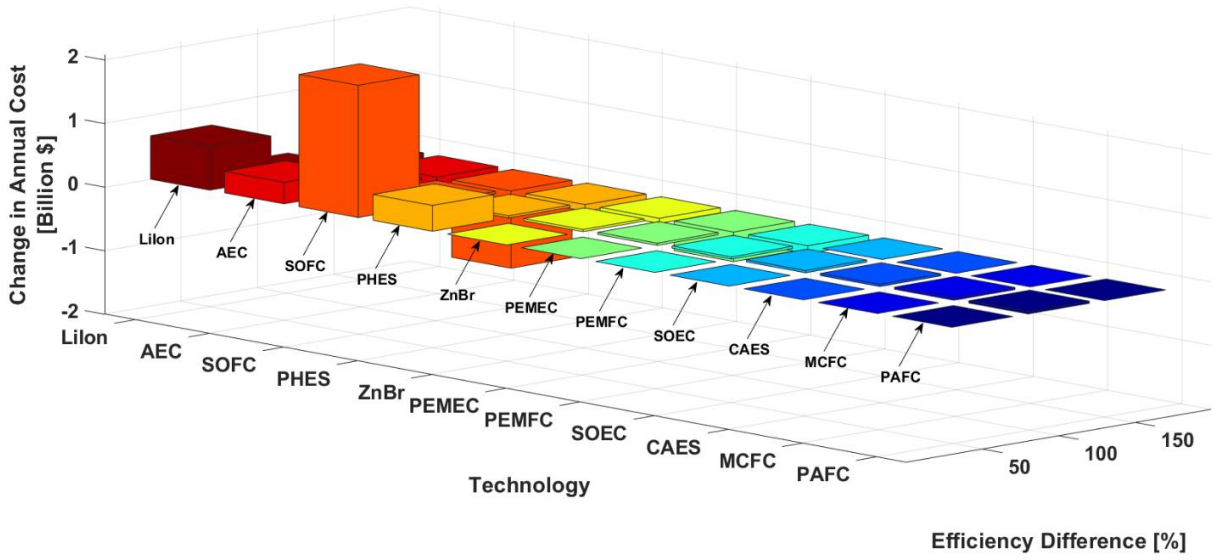

Figure 82: A three-dimensional representation of the change in annual cost with the different efficiency assumptions of each of the technologies listed.

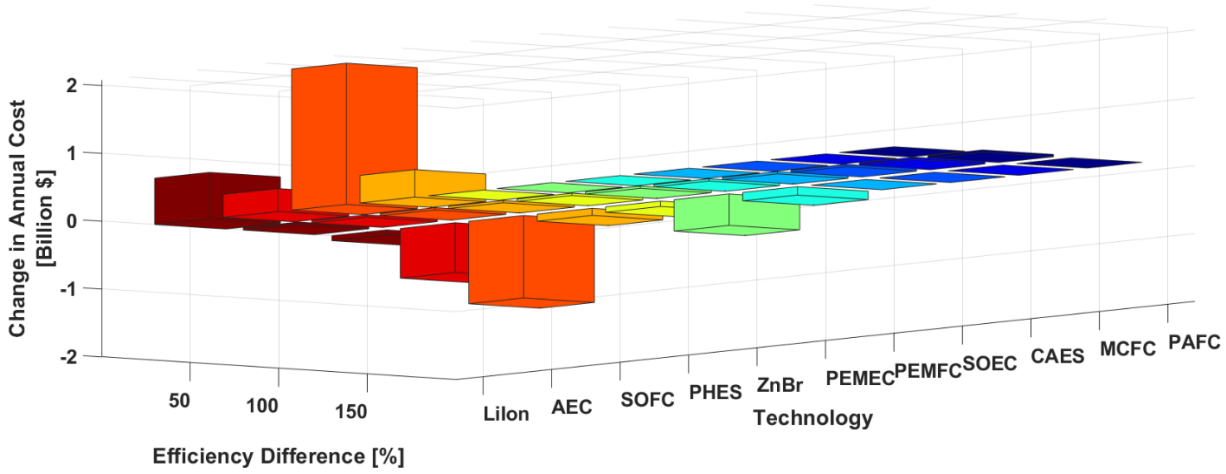

Figure 83: A different view of the three-dimensional representation of the change in annual cost with the different efficiency assumptions of each of the technologies listed.

The technologies that utilize ERE are displayed in Figure 84 and the technologies that generate electricity are displayed in Figure 85.

Overall, there is a decrease in ERE when there is an increase in efficiency this is due to the higher efficiency which allows the technologies to utilize less ERE to produce/store the same energy content. Specifically, for PEMECs, when there is an increase in efficiency PEMECs replace AECs. This shows that a higher efficient technology is preferable, which is intuitive. This is also seen when the AEC decreases in efficiency, the main electrolyzer type is switched from AEC to PEMEC. This shows that amongst AEC and PEMEC there is a fine line between efficiency and cost, either technology could be chosen depending on which is more efficient. SOECs are not chosen since they are already the highest efficient technology, increasing the efficiency has little effect on the technology selection as its costs are higher.

This trend is also seen between ZnBr BES and Li-Ion BES. With higher efficient ZnBr BES, there is a larger selection of ZnBr BES as compared to the Li-Ion BES. However, there is still a

slight selection of Li-Ion BES, this is due to Li-Ion BES still having higher efficiency even at its original efficiency assumption. On the other hand, if Li-Ion decreases in efficiency, a larger portion of the ERE use is dedicated to ZnBr BES. ZnBr BES also takes in portions of the ERE used in AECs as its able to store electricity for longer period times of Li-Ion BES and therefore can also provide some long duration storage that is met with HES, through the production of hydrogen from AECs.

Since the use of AECs is to produce hydrogen for both FCEVs and FCs, the change in FC efficiency can influence the ERE use of electrolyzers. In the case for SOFCs, if the efficiency decreases there is less ERE used in AECs and instead an increase used in Li-Ion BES with an overall decrease in ERE use. This is due to two main factors: 1. the lower efficiency of the SOFC reduces the benefits of HES and 2. the Li-Ion BES is more efficient that the AEC to store electricity and therefore less ERE is required.

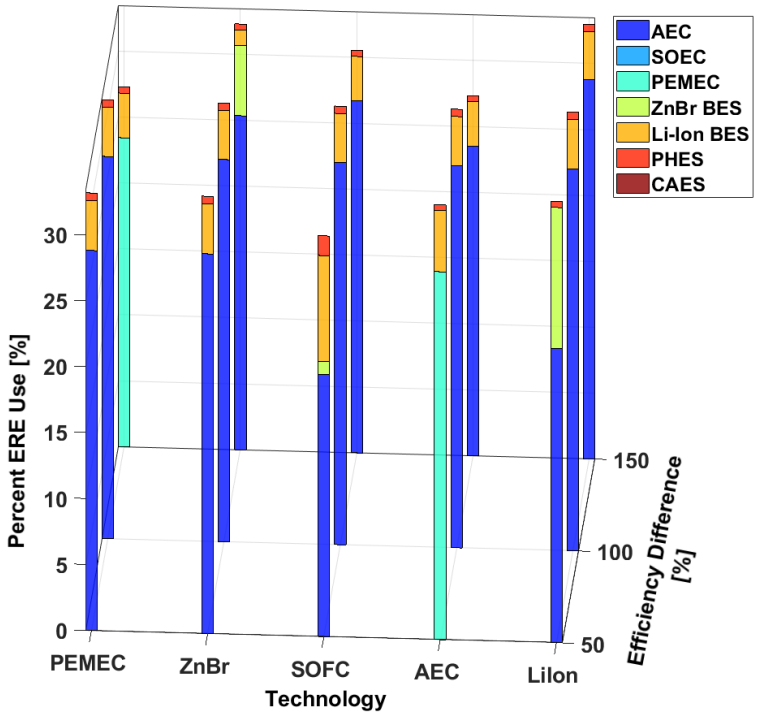

Figure 84: The change in assumed efficiency from the listed technologies result in changes in ERE use.

The decrease in SOFC efficiency saw not only a change in ERE but also a change in fuel cell technology. The decrease in efficiency results in a switch of primary fuel cell technology from SOFC to PEMFC. This shows that between the fuel cell technologies, efficiency is an important factor in determining which technology is chosen over the other. There is also an increase in Li-Ion BES used for electricity generation. An increase in SOFC efficiency has no visible difference. For the case of ZnBr BES and Li-Ion BES, the results from the ERE figure is similar to the electricity generation. With higher efficiency in ZnBr BES or lower efficiency in Li-Ion BES, there is an increase in ZnBr BES used for electricity generation. The ZnBr BES in both cases reduces the use of SOFCs. This is due to ZnBr BES having a slightly longer duration of storage than Li-Ion and therefore being able to provide longer duration storage which replaces the use of SOFCs which are primarily for long duration storage while also providing the short duration storage that Li-Ion BES provided.

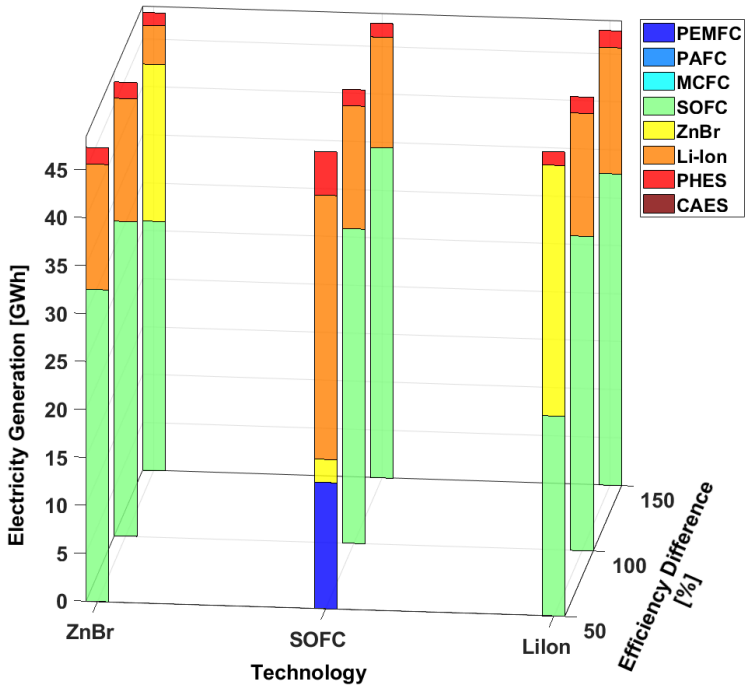

Figure 85:The change in assumed efficiency result in changes in technology portfolio for electricity generation.

8.4 Updated Economic Results

As an alternative to the 2045 Base Case Scenario, the following results will showcase updated figures with updated technology parameters and costs. There are just a few updated economic parameters from the ATB data for 2020, as opposed to the previous results which used ATB data for 2019 [259], the technical parameters are detailed in the APPENDIX C Task 5 Technology Parameters – 2045 Updated. There is very little difference in costs, but the main difference is a change in assumed Li-Ion BES efficiency going from 90% to 85%.

The main difference is a shift in optimal curtailment from 48% to 54%, seen in Figure 86 which shows the TSC with curtailment percentage for both the original base case results and the updated technology parameters. For reference, the stand alone TSC figure for the original base case is Figure 29. The TSC for the optimal of both the original 2045 base case and the updated

economic is $1.8 trillion and the TSC is similar across curtailment levels greater than 14%. This shows that the updated technology parameters and costs do not have a large change in the overall system.

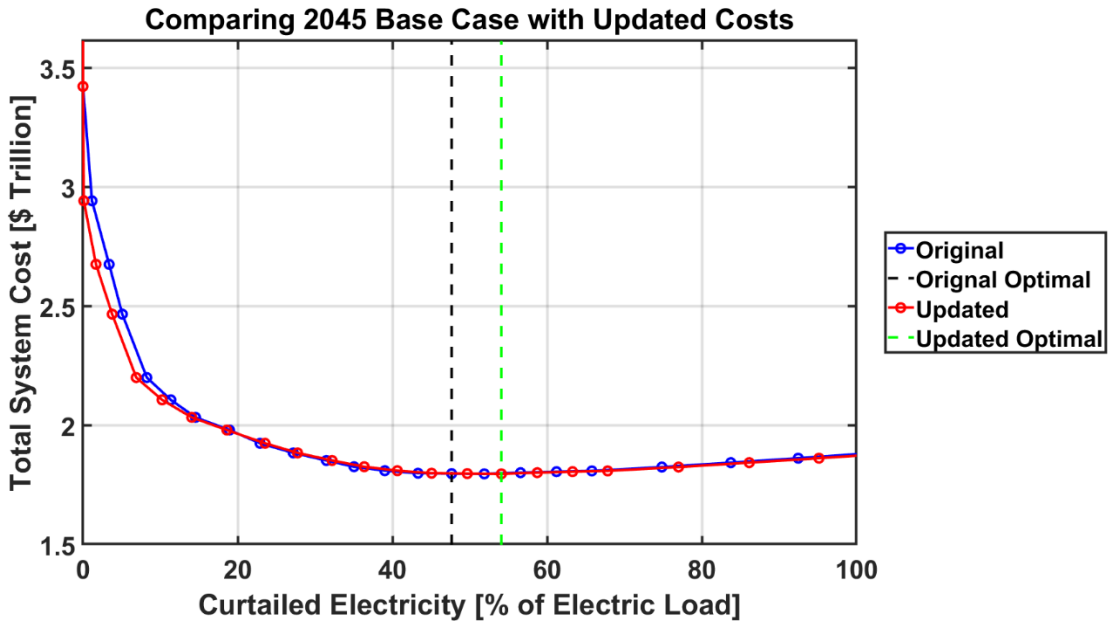

Figure 86: The total system cost using updated economics for the 2045.

However, the change in curtailment is primarily due to the shift of technology portfolio from Li-Ion to ZnBr, as seen by Figure 87 and Figure 88. Figure 87 is a direct comparison with Figure 31, and Figure 88 is a direct comparison with Figure 32. The main difference between the original 2045 base case results and the updated results is the switch from Li-Ion to ZnBr at higher curtailment levels. The original results did not select any ZnBr BES until at curtailments higher than the least-cost scenario. There is also an overall decrease in P2G2P: electrolyzer, HES, and fuel cell use for electricity production. There is a decrease in ERE in AEC and decrease in electricity production form SOFCs as compared to the base case. This is due to the ZnBr having slightly higher storage duration than Li-Ion BES and being more efficient than P2G2P. The lack of Li-Ion

BES requires ZnBr BES to satisfy the short duration storage but since it has slightly longer duration storage the ZnBr BES is also able to meet longer duration storage that is supplied by P2G2P and what Li-Ion could not supply.

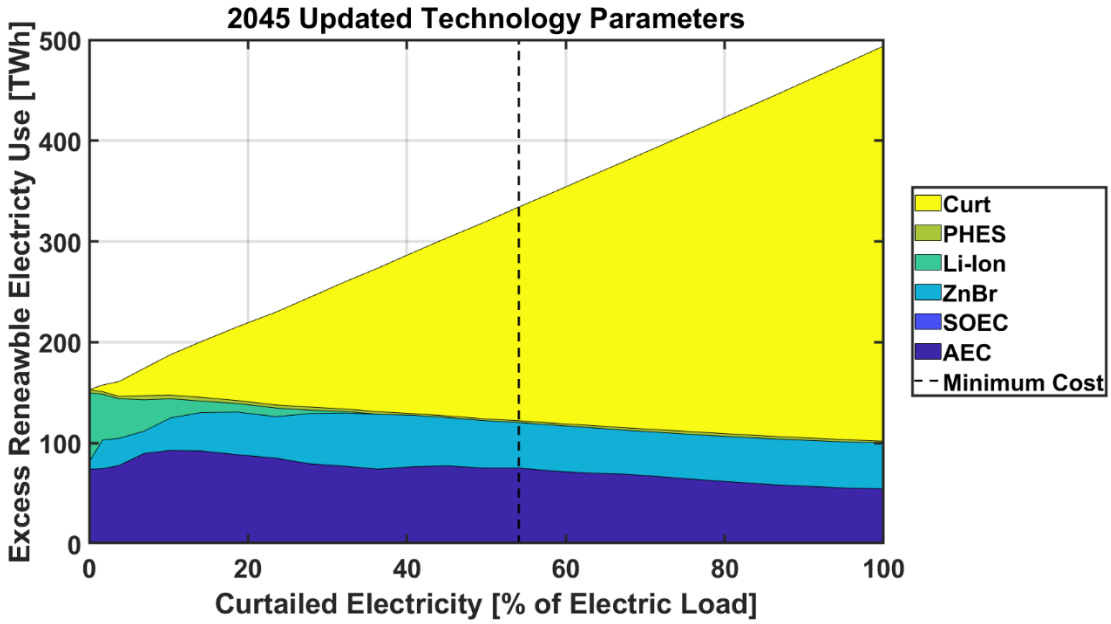

Figure 87: The technology portfolio of ERE use for the updated 2045 technology parameters.

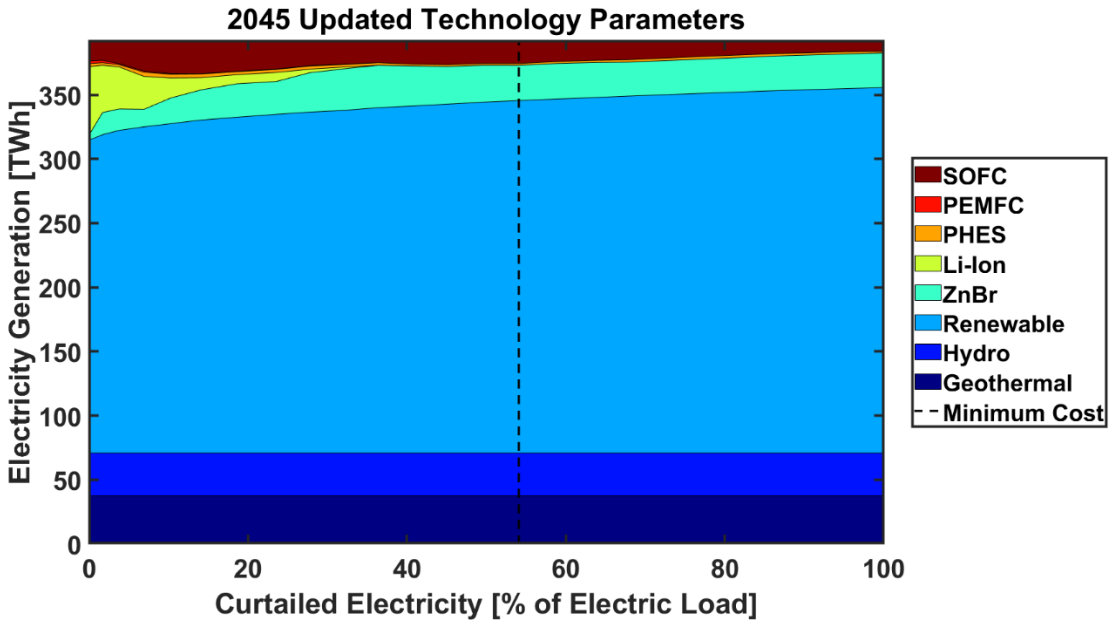

Figure 88: The technology portfolio for electricity generation for the updated 2045 technology parameters.

8.5 Ramping Limitations

The operation limitations of NGPP were not considered. The ramping up and down limitations were not considered, as the ramping timescale is smaller than the hourly resolution of the model [304]. Although within the hourly resolution of the model, the minimum limitations of NGPP operation were not considered. These limitations include the minimum part load operation and minimum up and down times. The integration of these limitations would require the optimization constraint to become a non-linear constraint, as the power capacity variable would have to be multiplied be an integer variable to incorporate the minimum operation constraints [305]. A post optimization analysis considering these minimal operation constraints were considered. The constraints are seen in Table 26.

Table 26: Operational constraints to determine the NGPP operation within minimum operation limitations.

Technology	**Minimum Part Load (%)**	**Minimum Up-Time (hours)**	**Minimum Down-Time (hours)**	**Maximum Power Capacity – determined from optimization (GW)**
NGPP-CC	40%	8	1	6.5
NGPP-CT	30%	2	1	13.6

This post optimization analysis removes the nonlinearity of having power capacity multiplied by an integer by setting the power capacity to what the optimization found. This analysis uses the NGPP capacities determined from the optimal 2030 case. The operation of the NGPP-CC and NGPP-CT in the original optimization results can be seen in the top portion of Figure 89. The bottom portion of the figure represents the operation of the NGPP-CC and NGPP-CT considering the minimum operation limitations. Overall, the NGPPs operate similarly, with NGPP-CC providing more consistent operation while the NGPP-CT handles most of the peaking and load following operation. However, in the case with the minimum operation limits, the NGPP-CC reduces operation at times. These times are to ensure that the NGPP-CT can operate above the minimum part load. As this analysis was limited to the power capacities of the original optimization results, the ramping down of the NGPP-CC is the only way for both power plants to remain within the operating constraints. However, if the ramping limitations were considered in the original optimization, the optimization may choose to have a slightly higher power capacity for the NGPP-CC as opposed to ramping it down. Although, this is only speculation and it is undeterminable based on the limitations of the original optimization and the constraint of maximum power capacity for the post optimization with NGPP operational limitation analysis.

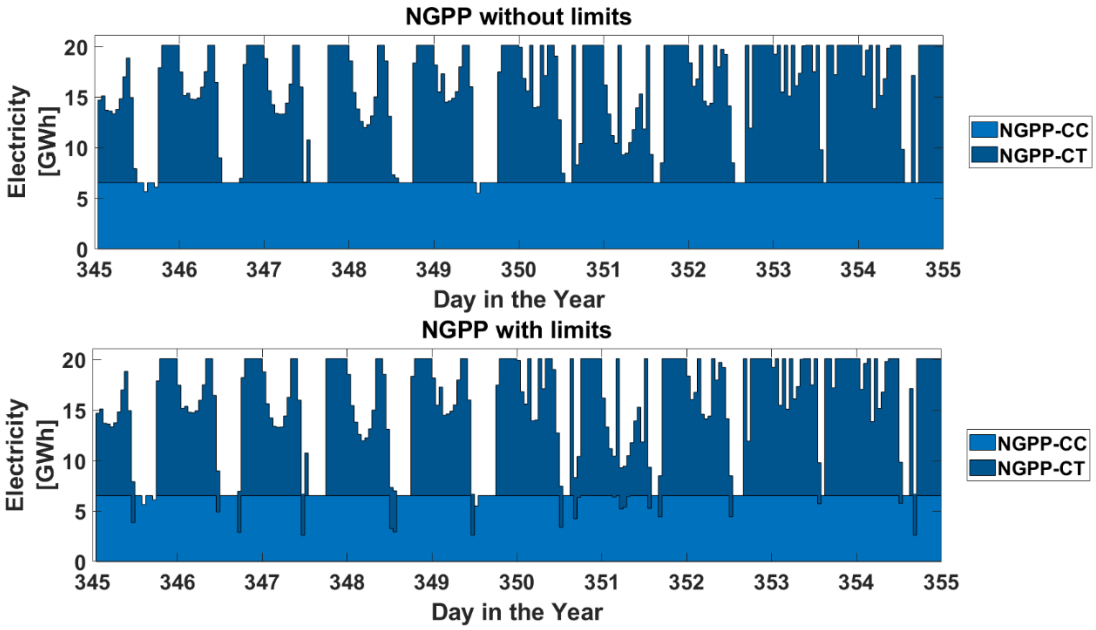

Figure 89: The hourly operation of NGPP. The top figure represents the operation of the original optimization results, the bottom figure represents the results considering the minimum operation limitations.

8.6 Fuel Cell Operation Limitations

Currently, industry standard is for SOFCs to operate as a based load. However, the previous results have showed them to operate dynamically, with the use of an electric heater to ensure thermal stability. The next results will show the 2045 Base Case with the restriction of fuel cell operation to operate with minimum loads, as a percent of capacity. The minimum operation percent can be seen in Table 27. Although a minimum for the MCFC was considered, it is still not selected, as seen in the 2045 Base Case, and the focus of this section will be on SOFCs.

Table 27: The minimum operation of fuel cell technologies, as a percent of total capacity.

Fuel Cell	**Percent minimum operation of the total capacity**
SOFC	30%

MCFC	50%

The input parameters for this analysis is based on the 2045 Base Case, with the addition of the fuel cell operation limitations. Overall, there is a slight change in TSC, as seen in Figure 90 which shows the plotted comparison between the TSC for the 2045 base case and results from the case considering the fuel cell operation limitations. There is only a slight increase in TSC in the FC limit case due to the need for complementing technologies to assist the SOFC which is limited in minimum operation, such as the implementation of PEMFCs. This can be seen in Figure 91 which when compared to Figure 32, there is a clear increase in selection of PEMFC for electricity generation. The PEMFC, which does not have the operational limitations that the SOFC has, is able to complement the SOFC to produce electricity during peak times by utilizing the long-duration HES.

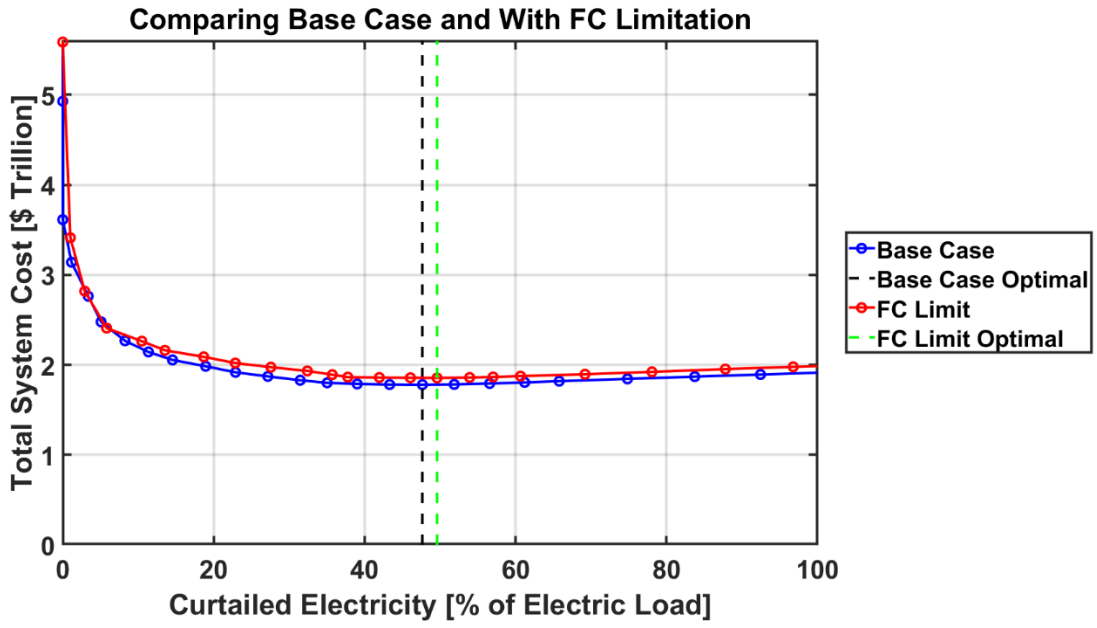

Figure 90:A comparison between the TSC of the 2045 base case with updated FC operational limitations.

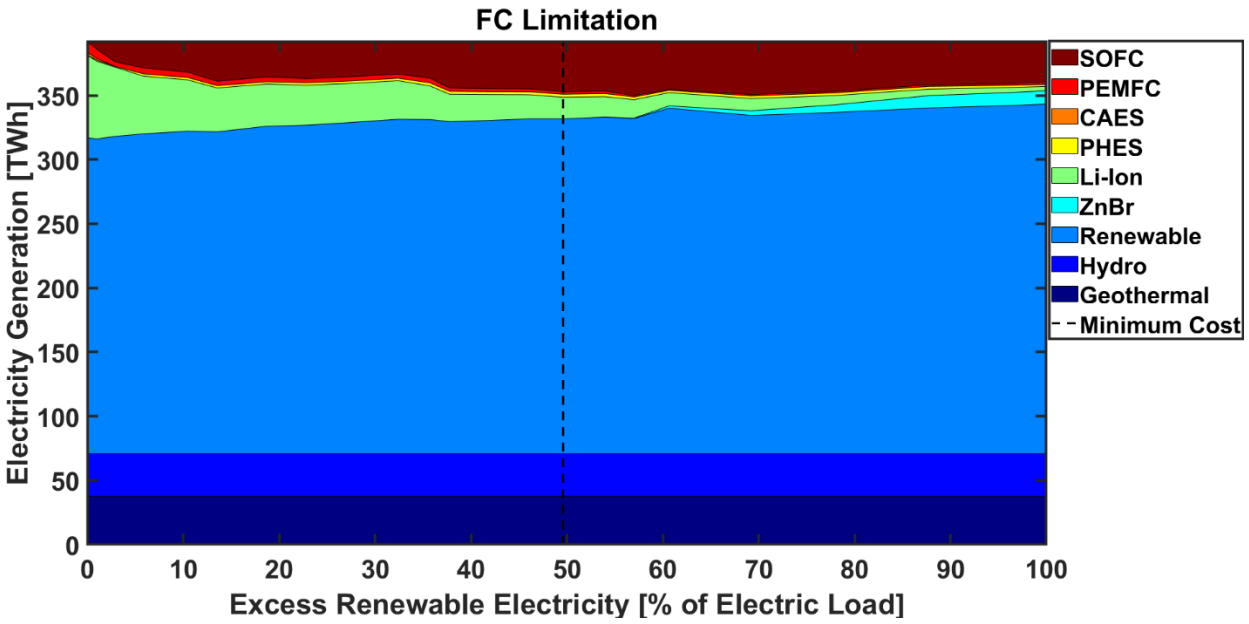

Figure 91: The technology portfolio of electricity generating technologies for the 2045 case considering FC operational limitations.

The hourly operation of the electricity generation technologies can be seen in Figure 92. This figure shows how the fuel cell, in this case the combination of the SOFC and the PEMFC, provide consistent electricity generation throughout each day while ramping up during times of low renewable generation.

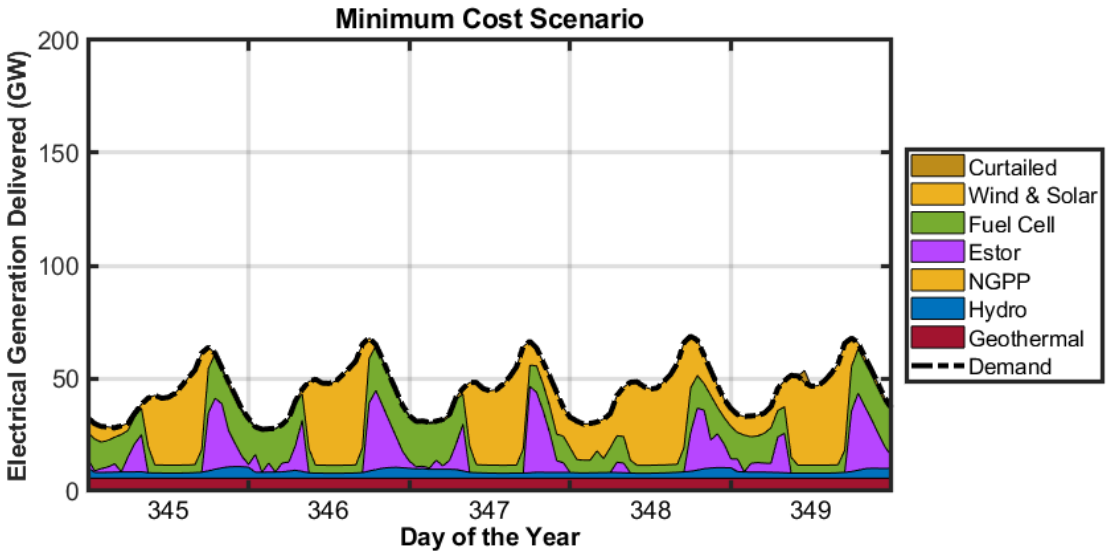

Figure 92: The hourly operation from days 345 to 350 showcase how the electricity generation technologies operate in tandem to match the electric demand.

8.7 Storage End Effects

A main constraint for the energy storage technologies, both hydrogen and closed-form, is that the beginning of the year must be equal to the end of year storage, as seen in Equation 32. This constraint is to ensure there is not an over assumption of energy storage at the beginning of the year, to ensure the total hydrogen consumed and produced are consistent throughout the year. In other words, this is to ensure that there is not more hydrogen consumed than produced and to ensure there is enough hydrogen stored to ensure the following year's operation. An analysis was conducted without the use of this end effect constraint and instead optimized for three consecutive years, with each year's demands and technology parameters equal to the 2045 year. The middle, second, year would represent the optimal storage that is necessary at the beginning of the year and the end of the year to ensure the proper operation for the previous and following year, a HES representation can be seen in Figure 93. The beginning of the first year

is assumed to have a full storage, to ensure there is proper HES for the beginning of the year. There are no constraints for the end of the third year. The years are separated by the dotted lines. The HES with the original constraint can be seen in Figure 94. The middle year of Figure 93 matches exactly to Figure 94. This shows that the end effect constraint assumption is effective to ensure proper storage at the beginning and end of the year to allow for consecutive operation.

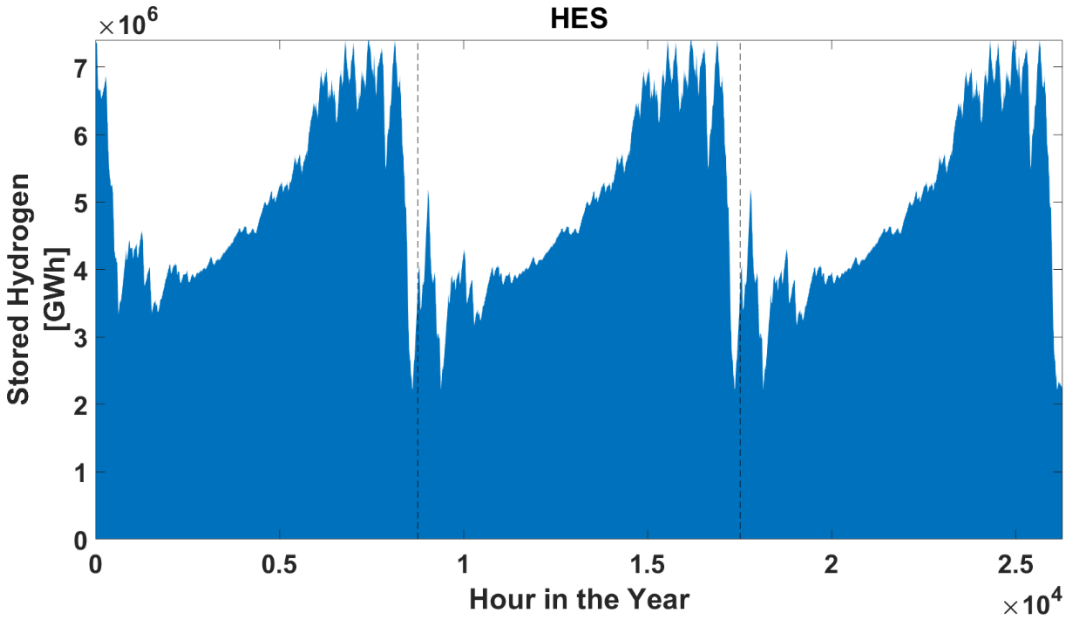

Figure 93: A three year optimization case, without the energy storage beginning and end of year constraints, to determine the storage end effects. The dashed vertical lines represent the separation of the different years.

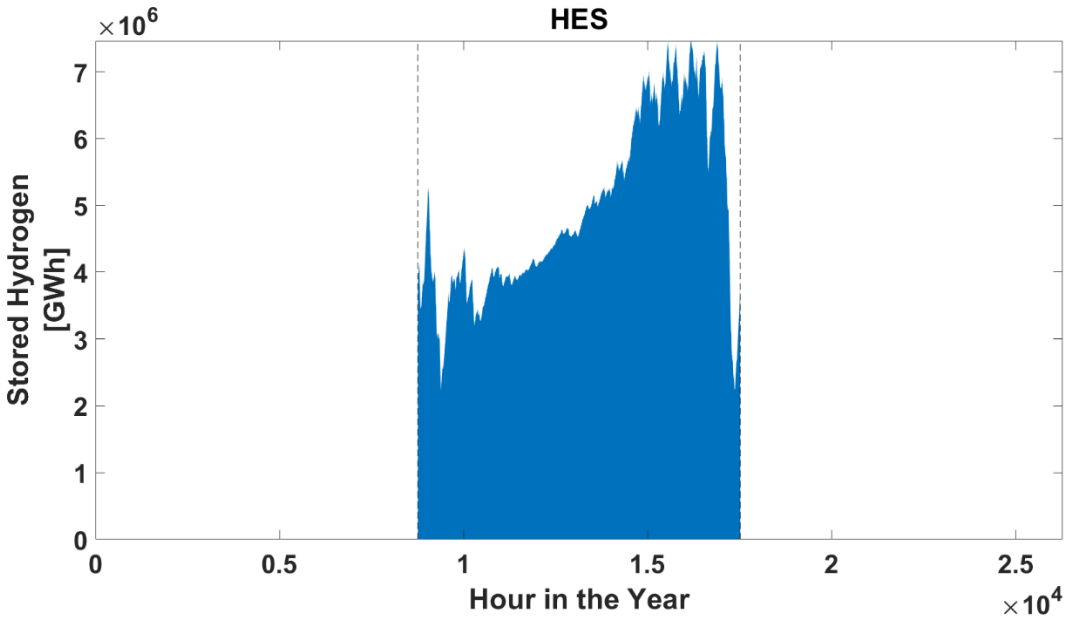

Figure 94: The original optimization with the end effect constraints. The dashed vertical lines represent the separation of the different years, since this is a single year it's plotted in the middle to be a direct comparison with the three-year end effects case.

9 TASK 6 – Multi-year optimization analysis to reach an 80% reduction in GHG emissions by 2045

The purpose of a multi-year run is to see how past technologies will influence the installation of new technologies as California transitions to more aggressive GHG emission goals. For example, in 2030 technologies will be installed to meet California's goals for 60% RPS which mean there will be natural gas power plants that have to be installed to meet the electric demand when renewable cannot. However, in 2045 as California reaches a zero-carbon grid those natural gas powerplants cannot use natural gas as a fuel but the capital investment to install the technologies have already occurred. The research question determines whether it is more economical to completely decommission those natural gas powerplant technologies or to install energy storage technologies which can utilize the variable renewable generation. The technology parameters and costs assumed for this analysis are from the updated 2020 ATB analysis, each year's technology parameters and demands are described in the APPENDIX C Task 6 Technology Parameters – 2035 & 2040.

9.1 Description of multi-year optimization

The optimization is the same as the methods described in Task 3 with an added ability to run for multiple years. The optimization objective function and constraints for year 1 (hours 1 to 8760) is the same. The year 3 (hours 8761 to 17520) is set to allow the year 1 technologies to run for the second year since they were previously installed. An example of the multi-year analysis using the ERE balance are such (Equation 46 to Equation 49):

Table 28: Example equations illustrating how to incorporate multiple consecutive years for technology installation and operation.

Year 1

$$1 \leq t \leq 8760$$

$$\sum_k P_{ELY_{1k},t} + \sum_k P_{FCVEren_{1k},t} + \sum_k P_{ESch_{1k},t} + \sum_k P_{EVren_{1k},t} + P_{CURT_1,t} = P_{ERE,t} \quad \text{Equation 46}$$

Year 2

$$8761 \leq t \leq 17520$$

$$\sum_k P_{ELY_{1k},t} + \sum_k P_{FCVEren_{1k},t} + \sum_k P_{ESch_{1k},t} + \sum_k P_{EVren_{1k},t} + \sum_k P_{ELY_{2k},t} + \sum_k P_{FCVEren_{2k},t} + P_{CUR_2,t} + \sum_k P_{ESch_{2k},t} + \sum_k P_{EVren_{2k},t} + P_{CURT_2,t} = P_{ERE,t} \quad \text{Equation 47}$$

Year 3

$$17521 \leq t \leq 26280$$

$$\sum_k P_{ELY_{1k},t} + \sum_k P_{FCVEren_{1k},t} + \sum_k P_{ESch_{1k},t} + \sum_k P_{EVren_{1k},t} + \sum_k P_{ELY_{2k},t} + \sum_k P_{FCVEren_{2k},t} + \sum_k P_{ESch_{2k},t} + \sum_k P_{EVren_{2k},t} + \sum_k P_{ELY_{3k},t} + \sum_k P_{FCVEren_{3k},t} + P_{CUR_3,t} + \sum_k P_{ESch_{3k},t} + \sum_k P_{EVren_{3k},t} + P_{CURT_3,t} = P_{ERE,t} \quad \text{Equation 48}$$

Year 4

$$26281 \leq t \leq 35040$$

$$\sum_k P_{ELY_{1k},t} + \sum_k P_{FCVEren_{1k},t} + \sum_k P_{ESch_{1k},t} + \sum_k P_{EVren_{1k},t} + \sum_k P_{ELY_{2k},t} + \sum_k P_{FCVEren_{2k},t} + \sum_k P_{ESch_{2k},t} + \sum_k P_{EVren_{2k},t} + \sum_k P_{ELY_{3k},t} + \sum_k P_{FCVEren_{3k},t} + \sum_k P_{FCVEren_{3k},t} + \sum_k P_{ESch_{3k},t} + \sum_k P_{EVren_{3k},t} + \sum_k P_{ELY_{4k},t} + \sum_k P_{FCVEren_{4k},t} + \sum_k P_{ESch_{4k},t} + \sum_k P_{EVren_{4k},t} + P_{CURT_4,t} = P_{ERE,t} \quad \text{Equation 49}$$

All other balance constraints follow this year 2 balance with the use of year 1 technologies. The objective function remains the same except with the added multiple of multiple years for the instant cost for year 1 technologies due to operating it for more than one year. The year multiplier is dependent on how many years the technology is simulated. For example, if the analysis is a two-year analysis, year 1 technologies run for 2 years and the instant cost is multiplied by two. Since year 2 technologies only run for 1 year, the instant cost is multiplied by one.

9.2 Results from 2030 to 2045 – Meeting California's goals

Since this analysis considers the operation and installation technologies across multiple years, the results will show the hourly annual operation from 2030 to 2045. This scenario considered the transition from a 60% RPS in 2030 to a zero-carbon electric grid in 2045 in 5-year increments. The technologies installed in previous years can be utilized for following years, therefore the state of charge is normalized across all years for the energy storage technologies shown in Figure 95. The absence of state of charge in previous years represents a lack of technology installation. For example, in the year 2030 only PHES and HES is utilized all other technologies are used in later years. ZnBr BES begins to be utilized in 2040 with a larger installation in 2045, as seen by the increase in state of charge. Li-Ion BES is only utilized in 2045. The installation of these energy storage technologies is promoted by both the increase in renewable generation and the constraint for a zero-carbon electric grid in 2045. The PHES and HES maintains state of charge throughout all years. The max state of charge for PHES, although normalized, is consistent throughout each year. This is due to the maximum limitation of PHES

capacity that is due to the availability of the resource. However, despite the same capacity for each of the years, there is a clear shift of state of charge from short duration in 2030 to longer and longer duration from 2035 to 2045. This shows that the increase in renewable generation equate to an increase in the need for long duration storage. The HES, since there is not a hard constraint for maximum capacity as there is for PHES, increases in state of charge over the years. As this plot is normalized, the state of charge for HES is normalized to the 2045 levels, which is significantly higher than the previous years. A closer look at the HES state of charge can be seen in Figure 96. The state of charge slightly fluctuates, but primarily stores the hydrogen throughout the year for long duration storage and stores hydrogen from year to year for use in 2045, with 2045 having the most significant changes in state of charge. The 2045 hourly state of charge for HES matches that of the 2045 Base Case, with storage primarily throughout the year with a significant use at the end of the year to match the variability of renewable generation.

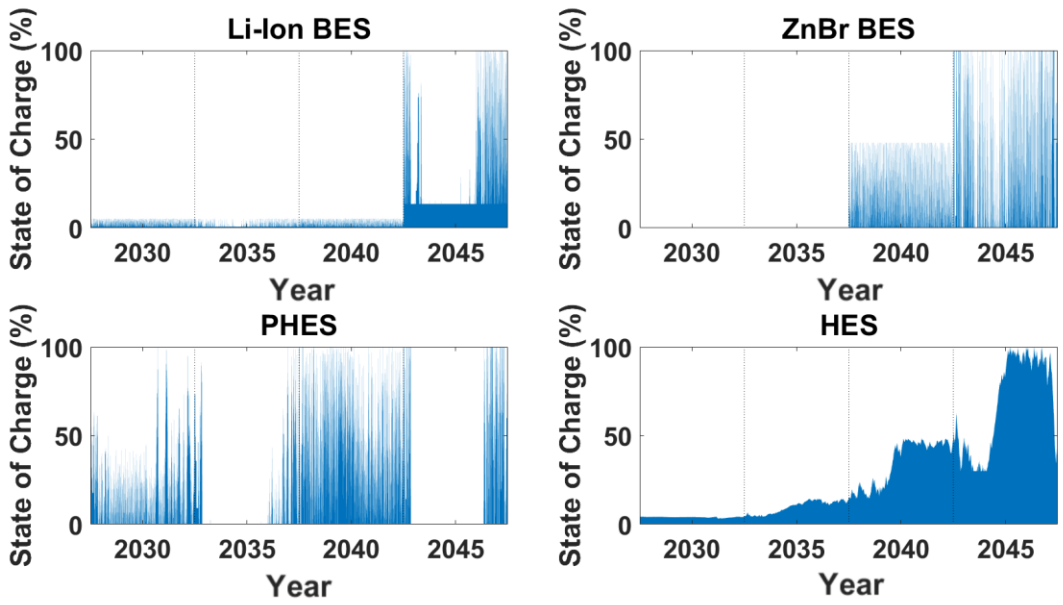

Figure 95: The hourly state of charge of various energy storage technologies. The dashed lines represent the sections of each year.

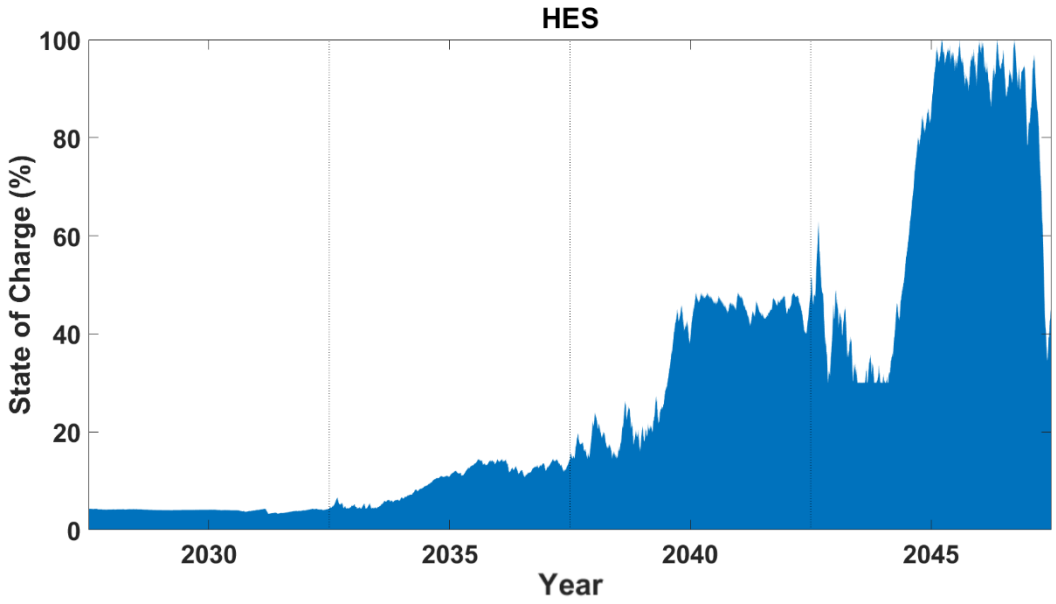

Figure 96: The hourly state of charge for HES, a closer look at the HES plotted in Figure 95.

The hourly electricity generation for the various technologies are shown in Figure 97. The Li-Ion BES, ZnBr BES, and PHES directly represents the discharge (the decrease in state of charge) in Figure 95. The SOFC represents the discharge of HES, shown in Figure 96, however does not represent all of the HES discharge as FCEVs also share the same HES system. The Li-Ion BES, ZnBr BES, SOFC, and NGPP are scaled to the maximum discharge from the Li-Ion BES which has the highest power capacity. This is to allow for proper comparison between the technologies. The PHES is not scaled as the capacity is significantly less than the other generation technologies. The renewable generation from wind and solar is also not scaled due to the significantly greater power capacity. Hydropower and geothermal is not shown as it is mostly base load and do not have much variation throughout the year.

Much like the state of charge, the Li-Ion BES and ZnBr BES are only utilized in later years. The Li-Ion is primarily used in the beginning and end of the year, while holding its state of charge throughout the middle of the year. This may be due to renewable generation able to meet the electric demand for most portions of the year. Li-Ion is primarily used as a peaking energy storage technology, as it has the highest capacity amongst the energy storage technologies. The ZnBr BES represents a more load following operation by the relatively consistent discharge throughout the year in 2040 and even in 2045 there is consistent discharge throughout the entire year with some peaks throughout the year to meet the peak demand. Consistent with the state of charge figure, the PHES shows a switch from short duration storage to long duration storage throughout the years by the discharge concentrated at the beginning and end of the years for 2035 to 2045 with almost no generation in the middle of the year in 2045.

The SOFC is used throughout all years, showcasing long duration storage through the lean discharge throughout the year. The SOFC has slightly more use throughout the year as compared to Li-Ion BES but has a more significant gap in the middle of the year than ZnBr BES. It seems that the SOFC and the ZnBr BES operate similarly with SOFC having more significant electricity generation at the end of 2045, which is also indicative by the hold of state of charge for HES until the end of 2045.

The NGPP shows high discharge throughout the years before 2045 and then a complete drop in 2045. This is due to the optimization constraint for no use of NGPP in 2045. The operation of the natural gas power plants throughout the early years are also indicative to the availability of renewable generation. There is more renewable generation throughout the middle of the year, therefore a decrease in NGPP operation; there is less renewable generation at the beginning and end of the year, therefore an increase in NGPP operation.

The renewable generation increases throughout the years; however, the annual profile remains the same. This shows that as renewable generation increases, the times of peak solar don't change and therefore the ERE generation during times of curtailment in the previous years will still be the same in later years and therefore the increase of renewable generation does not directly increase the penetration of renewable generation without use of ES technologies.

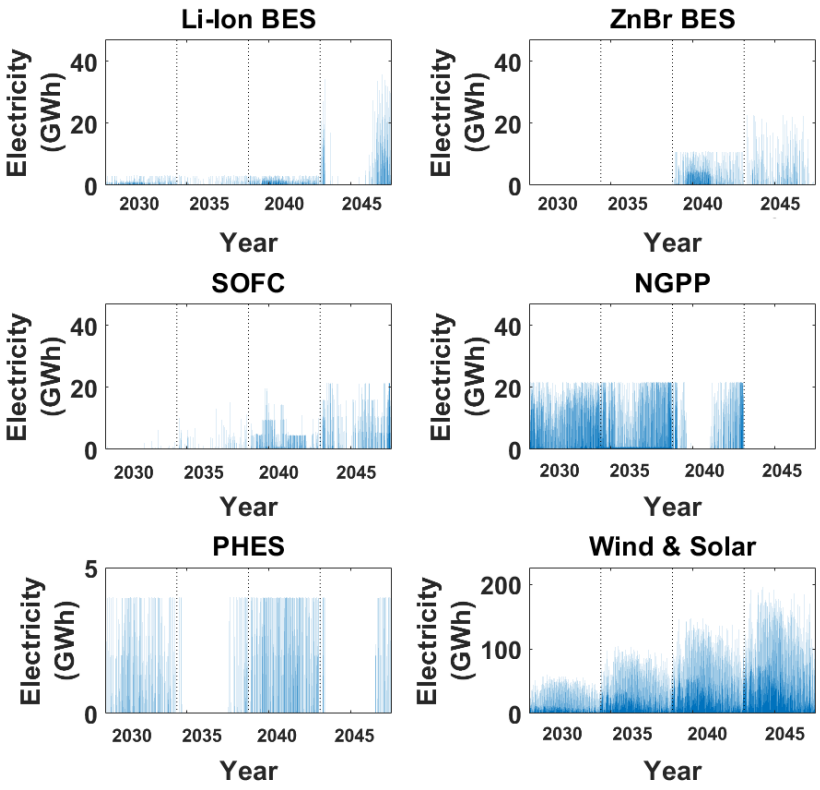

Figure 97: The hourly electricity generation of various technology types. The dashed lines represent the sections of each year.

10 SUMMARY AND CONCLUSIONS

10.1 Summary

The goal of this dissertation was to develop an optimization model which could consider the least-cost technology portfolio for technologies which utilize ERE to meet a stated system goal for California, such as a zero carbon electric grid for 2045 or a 60% RPS electric grid for 2030. This was accomplished reviewing current state of projections of technology pathways for the future energy system and formulating this methodology to fill the gaps. The literature review exposed three gaps: 1) cost and the comparison between energy storage technologies have been conducted, but the extent of comparison has not fully utilized optimization or modeling to understand the operational differences between the energy storage technologies, 2) the different uses of renewable electricity for the electricity, transportation, and natural gas sector have been explored, but separate from each other, and 3) the studies in literature explore curtailment of renewable generation but have not considered the optimal amount of curtailment. These research gaps are the primary focus of this dissertation which led to the projection of least-cost technology portfolios to meet the stated system goals.

Various scenarios were considered with the primary goals to achieve a 60% RPS electric grid by 2030 and a zero-carbon electric grid by 2045. The scenarios include considering or not considering the use of natural gas power plants that can utilize renewable gas produced from ERE and the effects of cost of carbon on the technology portfolio for a single representative year

analysis. A multi-year analysis was considered to determine the rollout of technologies from 2030 to 2045 by being able to utilize the technologies installed in the previous years.

10.2 Conclusions

10.2.1 Individual Technology Pathway Analysis

The main conclusions of this section, which consider the potentials of individual pathways to utilize ERE are as follows:

1. **Using excess renewable generation for supporting zero-emission transportation through battery electric or fuel cell electric vehicles provides the most cost-effective greenhouse gas emissions reductions.**

   Of the three different end uses for excess renewable generation considered in this study, excess renewable generation to produce hydrogen fuel or charge electric vehicles provides the lowest greenhouse gas mitigation investment costs, ranging between \$140/tonne and \$800/tonne CO_2e. With the exception being Level III immediate charging of electric vehicles, these costs were lower than the lower bound of the electrical energy storage (\$1900/tonne CO_2e) and renewable gas production (\$650/tonne CO_2e). This occurred due to renewably produced transportation fuel offsetting a high GHG-intensity fuel, while also providing a flexible load for improving electric grid operations when smart or vehicle-to-grid charging is employed.

2. **The greenhouse gas reduction benefits of electrical energy storage in capturing excess renewable generation for serving stationary electric loads is limited at high renewable penetrations.** When a large amount of renewable energy capacity was installed on the grid, the greenhouse gas intensity of the electric grid mix becomes very low, since fossil fuels (natural gas in California) comprise only a small amount of total generation. Therefore, using electrical energy storage to capture excess renewable generation to offset this small amount of fossil-fuel generation does not provide a significant incremental benefit for reducing greenhouse gas emissions. In the 70% RPS scenario, the maximum incremental benefit of electrical energy storage deployment was limited to 21 Mt CO_2e/yr for Li-Ion batteries, and in the 80% RPS scenario this limit decreases to 15 Mt CO_2e/yr for all energy storage types, regardless of efficiency. This indicates that for electrical energy storage to be most useful for greenhouse gas emissions reductions, discharging stored energy to support transportation loads is more beneficial.

3. **Renewable gaseous fuel production provides limited greenhouse gas reduction benefits but can provide significant benefits for reducing the levelized cost of energy.** Harnessing excess renewable generation for producing renewable gaseous fuels such as renewable methane or hydrogen provides a limited greenhouse gas emissions reduction benefit, since these fuels replace conventional natural gas which already has a relatively low greenhouse gas emissions intensity. However, these systems provided reductions in the levelized cost of energy due to the flexibility of electrolyzers in structuring their electric

loads to follow renewable variability and reducing variability impacts on other grid resources. Reductions in the levelized cost of energy ranged from $11/GJ to $14/GJ in the 70% renewable electric grid scenario, and between $41/GJ and $48/GJ in the 80% renewable electric grid scenario, which matches the reductions obtained by the transportation cases and exceeds the reductions obtained by the energy storage cases. This highlights the importance of load flexibility in reducing the costs of energy services, and the GHG emissions reductions from this end-use strategy can potentially be enhanced if renewable gaseous fuels could offset other, more GHG-intensive fuels.

4. **Load flexibility is critical for realizing potential GHG emissions reduction potential and reducing the cost of energy services.** This study accounted for the dynamic interactions between the dispatch of technologies associated with each end use and the electric grid and showed that lack of load flexibility compromised both GHG emissions reductions and decreases in the levelized cost of energy. For example, the results for Level III BEV charging shows that with intelligent (smart) charging, greenhouse gas emissions reductions of up to 79 Mt CO_2e/yr and levelized cost of energy reductions of $12/GJ were obtained in the 70% renewable electric grid scenario. For the exact same technology but without smart charging (i.e. uncoordinated charging), these benefits were significantly reduced to 58 Mt CO_2e/yr and $2/GJ, respectively. This highlights the importance of capturing the dynamics of flexibility and grid interactions when determining the potential

for GHG emissions reductions and cost savings from implementing these technologies to harness excess renewable generation.

10.2.2 2045 and 2030 Single Year Analysis

The main conclusions of this section which focused on a single year analysis for 2030, with a 60% RPS goal, and 2045, with a zero-carbon electric grid, are as follows:

1. **Overbuilding wind and solar and allowing some curtailment enable development of the lowest cost zero-carbon electricity system.**

   It is beneficial to allow curtailing some ERE generation rather than to employ expensive technologies to capture all the ERE. Overbuilding wind and solar capacity are relatively low-cost compared to installing energy storage capacity, based on future cost projections. The scale of storage needed to capture all available ERE and avoid curtailment is cost prohibitive.

2. **High round-trip efficiency is more important when the availability of ERE is limited, but low-cost energy capacity expansion becomes more important than efficiency when ERE is abundant.**

   At lower allowable curtailment levels, Li-Ion BES is the main contributor to energy storage due to its high efficiency. However, when spanning to higher ERE availability the Li-Ion BES is replaced with HES which is lower in efficiency, but also higher in energy capacity which enables HES to manage multiple timescales of variability. This is due to the

higher amount of ERE generation which can be used by lower efficiency technologies and can directly meet the electric demand, which also lowers the need for the highly efficient energy storage technologies.

3. **Long duration is primarily necessary when reaching higher levels of renewable penetration goals, such as 2045 zero carbon electric grid.**

The need for long duration storage for the 2030 60% RPS goal is not prevalent as compared to the 2045 zero carbon electric grid goal. The optimal energy storage technology for 2030 is PHES, as the costs are low and there is not a large need for energy storage technologies as most of the renewable electricity can directly meet the electric demand. However, as the electric grid transitions to zero carbon, the seasonal variability of renewable generation has a larger effect on energy storage rising to the need of long duration storage in which is optimal if used for HES technologies.

4. **Dispatchable power capacity is required regardless of increase of renewable generation.**

The generation from wind and solar cannot directly match the electric demand, therefore there is a consistent need for dispatchable power. This can be seen as the power capacity of dispatchable resources, such as fuel cells, energy storage, and natural gas technologies, remains relatively constant despite an increase in power capacity of wind and solar.

5. **To reduce GHG emissions across all sectors, the use of fossil fuel natural gas power plants may be optimal.**

   By imposing a cost of carbon, the reduction of GHG emissions is weighted relative to the cost of the system. This cost of carbon analysis shows that ERE is used to reduce GHG emissions from the natural gas system before completely zeroing out the GHG emissions from the electricity sector. The use of fossil fuel natural gas power plants is important for a least-cost technology portfolio by reducing the need for large energy storage technologies. Instead, investments could be made to reduce GHG emissions by producing renewable gas for the natural gas sector which allows for better temporal flexibility than focusing on a zero-carbon electric grid which would require large installations of energy storage technologies.

10.2.3 2030 to 2045 Multi-year Analysis

The main conclusions of this section which focused on the multi-year analysis considering years 2030 to 2045 in 5-year increments are as followed:

1. **There is a transition from short duration to long duration storage with increasing renewable generation.**

   Every year there is an increasing amount of installed renewables which result in an increase in renewable generation. However, due to the seasonal variability of renewable generation the increase of renewable generation that can directly meet the electric demand is not directly related to the overall increase of renewable generation. In other words, installing more renewable technologies only increases the peak generation

which already cannot directly meet the electric demand. This calls for larger installations and longer duration energy storage required to capture the seasonal variation that is more apparent at higher amounts of installed renewables.

2. **Natural gas power plants are selected until the zero-carbon electric grid constraint in 2045 is implemented.**

   The use of fossil fuel natural gas power plants is the least-cost solution, regardless of renewable generation. This is due to the relatively lower cost of NGPP, the inability of renewable generation to directly meet the electric demand, and the relatively larger cost of energy storage technologies. The absence of NGPP in 2045 is only due to the zero-carbon electric grid constraint. This shows that implementation of policy is necessary to push forward the road to a zero-carbon future, as the least cost scenarios will include the use natural gas power plants regardless of the capacity of installed renewables.

10.3 Future Work

The spatial aspects to installing various technologies to utilize the renewable electricity was not considered. Although, it is not included in this study, it is important to understand the spatial availability to achieve an understanding of the feasibility of the optimally selected technology portfolio. For example, the location of renewable gas injection points into the natural gas pipeline may not directly correlate to the availability of renewable generation. Figure 98 and Figure 99 show the concentrations of solar and wind, respectively, relative to potential injection points in the Southern California Gas (SoCalGas) jurisdiction. These figures were produced through ArcGIS and by Emily Dailey, a fellow graduate student at the Advanced Power and Energy

Program. There are limitations on the availability of projects with the location of the natural gas pipeline and sufficient concentration of renewable generation. Future work should consider the availability to inject renewable gas, produced from renewables, into the natural gas pipeline. There are also spatial limitations in the natural gas pipelines. Therefore, the amount of renewable gas injection is spatially limited to the pressures and volumes that the pipelines can handle.

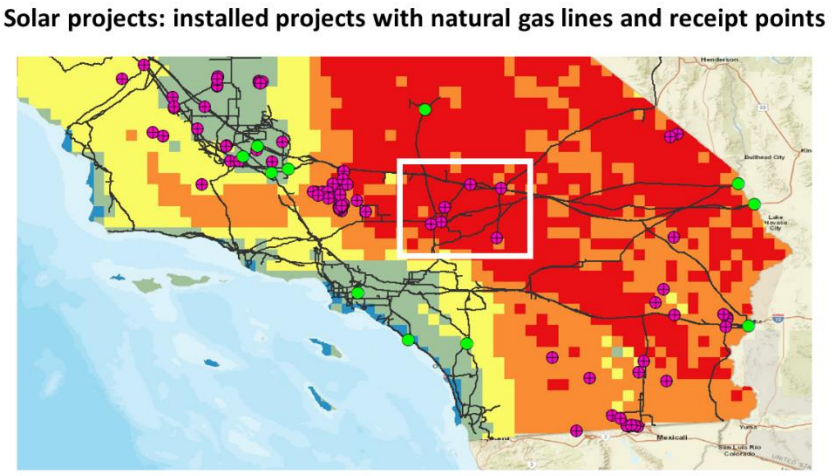

Figure 98: A map of SoCalGas system relative to the concentration of solar; the warmer the color (the more red), the higher the concentration of solar. The purple dots represent potential injection points for renewable gas, the lines represent the natural gas pipeline, the green points represent the receipt points going into state of SoCalGas jurisdiction. The white box represents the area with the highest project potential.

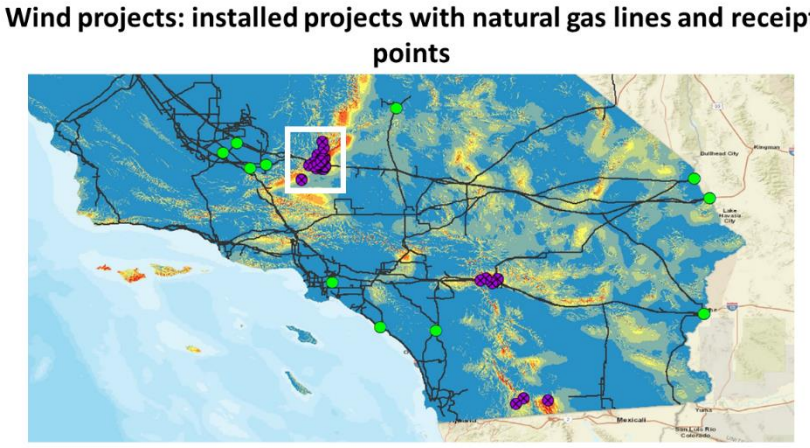

Figure 99: A map of SoCalGas system relative to the concentration of solar; the warmer the color (the more red), the higher the concentration of wind. The purple dots represent potential injection points for renewable gas, the lines represent the natural gas pipeline, the green points represent the receipt points going into state of SoCalGas jurisdiction. The white box represents the area with the highest project potential.

The spatial use of the selected technologies and capacity was also not considered. The area taken by the various technologies, such as FCs and BESs, will be significant when considering such large capacities for the 2045 scenarios. The location of these technologies may also affect the operation. For example, although there is ample space in the desert, the high heat may lower the efficiency of the technologies or there may be indigenous plant and animal life that must be protected and therefore the space cannot be utilized.

Renewable transportation has the highest potential to decrease GHG emissions, with the greatest potential seen in V2G BEV charging due to replacing inefficient, conventional, high GHG emitting internal combustion vehicles. However, the optimization model does not consider the different mixes of ZEVs, but rather consider the ZEV demand to be based on the year, as

compared to utilizing ERE for energy storage or the natural gas system. This is due to more operational limitations that ZEVs present as compared to the other sectors. ZEVs have limitations regarding operational limitations of miles traveled and dwelling periods which would be more difficult to incorporate into this system wide analysis. Although the results were not shown, if the ZEVs could be chosen by the optimization to reduce GHG emissions, in the case considering the cost of carbon. All vehicles would be chosen as ZEVs, as they displace higher GHG emitting gasoline vehicles, as compared to the combustion of natural gas as seen by the individual technology pathway analysis. However, this may not be feasible as there are limitations to the type of vehicles that are required to meet individual needs with regards to charging/fueling time and spatial availability that were not considered in this study.

The following paragraph relates to areas where the optimization model could be improved, but due to limitation on the readily available data it could not be implemented into this analysis.

This analysis was limited to an hourly timescale. Shorter timescales of seconds to minutes would limit the use of certain technologies, such as slow start-up SOFCs where cycling can rapidly degrade the cells [306]. This also affects the ramping of natural gas power plants. The ramping limitations of natural gas power plants were not considered, this is due to not considering an exact number of natural gas power plants and rather an assumption of a continuous natural gas power plant network where they could operate in tandem to produce the electricity generation determined by the optimization model. The modeling limitation is such that the consideration of ramping would cause the optimization to become a non-linear problem, due to the requirement of initializing the natural gas capacity in order to impose integer logic for ramping constraints [305].

The study results are sensitive to the input costs and energy demands to be satisfied used in this analysis. Many studies provide a wide range of costs for different technologies. There are many different estimates for electrolyzer costs, ranging from optimistic to conservative projections [307], [308]. However, by spanning different technology types with differing costs and operational values the main results of this study capture the various energy storage types for short, medium, and long duration storage. Leadbetter and Swan (2012) found Li-Ion BES were suitable for short duration storage [309]. Their study also explored the suitability of lead-acid batteries for short duration and vanadium redox and sodium-sulfur for long duration storage. A

sensitivity analysis was performed for the cost-optimal cases, with the main focus was to understand which technologies were sensitive to the assumed costs and efficiency, but additional runs spanning the non-optimal cases were not considered.

This study does not consider the electricity market. The operation of each of these technologies were assumed to work in tandem without need for forecasting or ensuring power quality. The main assumption of this optimization logic is the complete interworking and cooperation of each of the electricity generation technologies, which does not mimic current electricity production infrastructure. For example, the curtailed electricity is assumed to just be not generated at all while there are cases in California where excess renewable generation has caused California to have to pay other states to take in the electricity [178]. The current energy market are auctions where electric suppliers offer to sell their electricity for a particular bid price while an entity that serves the customer's energy demand bids for that electricity [310], [311]. However, this market may not work for a future electric grid that is heavily reliant on renewable generation. With times of excess renewable generation, the price of electricity would be negative, which would not be a sustainable market. Therefore, the extent of how the market will function in the future was not considered.

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APPENDIX A

This section details an example of the simplex method, primarily following another example [312], [313].

Maximize:	$P = 7x_1 + 8x_2 + 10x_3$	
Constraints:	$2x_1 + 3x_2 + 2x_3 \leq 1000$ $x_1 + x_2 + 2x_3 \leq 800$ $x_1, x_2, x_3 \geq 0$	

Add slack variables $(s_1, s_2)$for each constraint and rewrite the equations, the last constraint is not necessary to continue.

Maximize:	$-7x_1 - 8x_2 - 10x_3 + P = 0$	
Constraints:	$2x_1 + 3x_2 + 2x_3 + s_1 \leq 1000$ $x_1 + x_2 + 2x_3 + s_1 \leq 800$	

Turn the equations to a matrix form

$$\begin{array}{c} \\ s_1 \\ s_2 \\ P \end{array}\left[\begin{array}{cccccc|c} x_1 & x_2 & x_3 & s_1 & s_2 & P & \\ \hline -2 & -3 & -20 & 1 & 0 & 0 & 1000 \\ -1 & -1 & 2 & 0 & 1 & 0 & 800 \\ -7 & -8 & -10 & 0 & 0 & 1 & \end{array}\right]$$

Row reduce by looking at the bottom row and choose the number that is the furthest to the left (highlighted in red) which is now known as the pivot column. Divide the very right column by the number in the pivot column (1000/2 and 800/2). Take the smaller number to be the pivot number (highlighted in blue). The reduce the rows so the pivot column is equal 1 and the other rows is 0. The pivot row is also labeled as the pivot variable

$$\begin{array}{c} \\ s_1 \\ s_2 \\ P \end{array}\left[\begin{array}{cccccc|c} x_1 & x_2 & x_3 & s_1 & s_2 & P & \\ \hline -2 & -3 & -20 & 1 & 0 & 0 & 1000 \\ -1 & -1 & 2 & 0 & 1 & 0 & 800 \\ -7 & -8 & -10 & 0 & 0 & 1 & 0 \end{array}\right]\begin{array}{c} x_2 \\ \frac{1000}{2} = 500 \\ \frac{800}{2} = 400 \end{array}$$

$$\frac{1}{2}R_2 \to R_2$$

$$10R_2 + R_3 \to R_3$$

$$-2R_2 + R_1 \to R_1$$

$$\begin{array}{c} \\ s_1 \\ x_3 \\ P \end{array}\left[\begin{array}{cccccc|c} x_1 & x_2 & x_3 & s_1 & s_2 & P & \\ \hline -1 & -2 & -00 & 1 & -1 & 0 & 200 \\ -\frac{1}{2} & -\frac{1}{2} & 1 & 0 & \frac{1}{2} & 0 & 400 \\ -2 & -3 & -00 & 0 & 5 & 1 & 4000 \end{array}\right]\begin{array}{c} \frac{200}{2} = 100 \\ \frac{400}{\frac{1}{2}} = 800 \end{array}$$

Repeat row reduction and pivot column until there are no negatives in the bottom row

$$\frac{1}{2}R_1 \to R_1$$

$$-\frac{1}{2}R_1 + R_2 \to R_3$$

$$3R_1 + R_3 \to R_3$$

$$\begin{array}{c} \\ x_2 \\ x_3 \\ P \end{array} \left[\begin{array}{cccccc|c} x_1 & x_2 & x_3 & s_1 & s_2 & P & \\ \hline \frac{1}{2} & -1 & -00 & \frac{1}{2} & -\frac{1}{2} & 0 & 100 \\ -\frac{1}{4} & -0 & 1 & -\frac{1}{4} & \frac{3}{4} & 0 & 350 \\ -\frac{1}{2} & -0 & -00 & \frac{3}{2} & \frac{7}{2} & 1 & 4300 \end{array}\right] \begin{array}{c} \\ \frac{100}{\frac{1}{2}} = 200 \\ \frac{350}{\frac{1}{4}} = 1400 \\ \\ \end{array}$$

Repeat row reduction and pivot column until there are no negatives in the bottom row

$$2R_1 \to R_1$$

$$-\frac{1}{4}R_1 + R_2 \to R_2$$

$$\frac{1}{2}R_1 + R_3 \to R_3$$

$$\begin{array}{c} \\ x_1 \\ x_3 \\ P \end{array}\left[\begin{array}{cccccc|c} x_1 & x_2 & x_3 & s_1 & s_2 & P & \\ \hline -1 & -2 & -00 & 1 & -1 & 0 & 200 \\ -0 & -\frac{1}{2} & 1 & -\frac{1}{2} & 1 & 0 & 300 \\ -0 & -1 & -00 & 2 & 3 & 1 & 4400 \end{array}\right]$$

There are no more negative numbers in the bottom row, therefore the solution is determined. Maximum of 4400 is achieved when:

$$x_1 = 200$$

$$x_3 = 300$$

$$x_2 = 0$$

$$s_1 = 0$$

$$s_2 = 0$$

APPENDIX B

Table B29: 2030 common load parameters for California

Sector	**Year 2030 Annual Electric Load Magnitude [GWh]**	**Sector**	**Year 2030 Annual Gas Demand [MMBtu]**
Residential	91,619	**Transportation – Hydrogen Production**	14,776,645
Commercial	95,819		
Industrial	80,483	**Sector**	Year 2030 Annual Gas Demand [Mtherm]
Transportation - Light Duty Electric Vehicles	13,954	**Natural Gas**	12,805
Transportation - Other Electric Vehicles	8,070		

Table B30: 2035 common load parameters for California

Sector	**Year 2035 Annual Electric Load Magnitude [GWh]**	**Sector**	**Year 2030 Annual Gas Demand [MMBtu]**
Residential	98,608	**Transportation – Hydrogen Production**	37,967,837
Commercial	99,939		
Industrial	78,899	**Sector**	Year 2030 Annual Gas Demand [Mtherm]
Transportation - Light Duty Electric Vehicles	28,25	**Natural Gas**	10,951
Transportation - Other Electric Vehicles	15,875		

Table B31: 2040 common load parameters for California

Sector	**Year 2040 Annual Electric Load Magnitude [GWh]**	**Sector**	**Year 2030 Annual Gas Demand [MMBtu]**
Residential	107,471	Transportation – Hydrogen Production	69,360,033
Commercial	110,353		
Industrial	76,634	Sector	Year 2030 Annual Gas Demand [Mtherm]
Transportation - Light Duty Electric Vehicles	39,351	Natural Gas	8,800
Transportation - Other Electric Vehicles	25,867		

Table B32: 2045 common load parameters for California

Sector	**Year 2045 Annual Electric Load Magnitude [GWh]**	**Sector**	**Year 2030 Annual Gas Demand [MMBtu]**
Residential	112,088	**Transportation – Hydrogen Production**	90,894,055
Commercial	122,956		
Industrial	74,414	**Sector**	Year 2030 Annual Gas Demand [Mtherm]
Transportation - Light Duty Electric Vehicles	46,863	**Natural Gas**	6,902
Transportation - Other Electric Vehicles	34,401		

Table B33: 2030 percentage of Variable Renewable Resource Mix

Variable Renewable Resource Type	**Percentage of Total Variable Renewable Mix by Installed Capacity [%]**
Onshore Wind	19.3%
Rooftop PV	28.9%
Utility-Scale PV	51.8%

The projection of variable renewable resource capacity for 2035 and 2040 is linearly determined between 2030 and 2045 capacities.

Table B34: 2030-2045 installed capacity of dispatchable resources, there is not a change between the different years.

Dispatchable Zero-Carbon Resource Type	**Installed Capacity [GW]**
Hydropower (Aggregated – Large and Small)	15.6
Geothermal	4.46
Nuclear	0.00
Biomass	0.00

APPENDIX C

The following Appendix will detail the technology parameters and costs for each of the tasks.

Task 2 Technology Parameters

Table C35: Efficiencies of various technology pathways.

Equipment	ZnBr Flow Battery	Lithium-Ion Battery	Advanced Lead-Acid Battery	Sodium-Sulfur Battery
Efficiency	0.65	0.90	0.89	0.75
Efficiency Unit	MWh-in/MWh-out	MWh-in/MWh-out	MWh-in/MWh-out	MWh-in/MWh-out

Fuel Cell: PEM (H2 Fuel)	Fuel Cell: PAFC (H2 Fuel)	Fuel Cell: MCFC (H2 Fuel)	Fuel Cell: SOFC (H2 Fuel)	Alkaline Electrolyzer (H2A)
6.300	6.300	6.300	6.300	46
MMBtu H2/MWh	MMBtu H2/MWh	MMBtu H2/MWh	MMBtu H2/MWh	kWh/kg H2

Solid Oxide Electrolyzer	PEM Electrolyzer	Methanator	H2 Fueling, Gaseous, Central Electrolyzer H2	H2 Fueling, Liquid, Central ElectrolyzerH2	H2 Fueling, Gaseous, Onsite Electrolyzer
35.1	50.2	9.558	4	15	70
kWh/kg H2	kWh/kg H2	kg H2/MMBtu CH4	kWh/kg H2*	kWh/kg H2*	kWh/kg H2*

*For H2 production and compression to 700 bar

Table C36: Economic parameters for the various technology pathways.

Technology Pathway Number			**1**	**2**
Pathway Description		**Base Case**	**Alkaline Electrolyzer H2 Injected into Distribution System**	**Solid Oxide Electrolyzer H2 Injected into Distribution System**
Instant Cost ($/kW)			289.62	466.60
Fixed Operation and Maintenance ($/kW-yr)			10.43	15.40
Variable Operation and Maintenance ($/MWh)			1.24	13.00
RPS (%)	70% scenario	70.08	73.73	73.65
	80% scenario	80.99	86.65	86.41
Electric Grid Emissions (tons CO2)	70% scenario	29,208,235.28	31,519,870.20	31,738,063.30
	80% scenario	12,684,390.61	16,577,214.28	17,240,531.86
LCOE ($/GJ)	70% scenario	64.87	50.93	51.15
	80% scenario	100.93	54.30	54.06
CO2 emission reduction (tons CO2)	70% scenario	0.00	9,877,790.93	13,444,918.11
	80% scenario	0.00	31,428,941.16	41,734,490.72
Curtailed Energy (MWh)	70% scenario	72,870,516.16	5,715,314.97	5,614,439.85
	80% scenario	211,189,727.26	5,937,533.67	5,684,953.47

3	4	5	6	7	8	9
PEM Electrolyzer H2 Injected into Distribution System	**Alkaline Electrolyzer H2 Injected into Transmission Pipeline**	**Solid Oxide Electrolyzer H2 Injected into Transmission Pipeline**	**PEM Electrolyzer H2 Injected into Transmission Pipeline**	**Alkaline Electrolyzer H2 to Methanator; CH4 Injected into Distribution System**	**Solid Oxide Electrolyzer H2 to Methanator; CH4 Injected into Distribution System**	**PEM Electrolyzer H2 to Methanator; CH4 Injected into Distribution System**
398.30	322.36	499.34	431.04	489.45	788.55	673.13
14.32	10.43	15.40	14.32	13.76	20.32	18.91
0.17	1.24	13.00	0.17	1.57	16.39	0.22
73.76	73.73	73.65	73.76	73.73	73.65	73.76
86.72	86.65	86.41	86.72	86.65	86.41	86.72
31,466,985.35	31,519,870.20	31,738,063.30	31,466,985.35	31,519,870.20	31,738,063.30	31,466,985.35
16,413,011.42	16,577,214.28	17,240,531.86	16,413,011.42	16,577,214.28	17,240,531.86	16,413,011.42
51.78	51.07	51.28	51.91	52.48	53.52	53.66
55.60	54.47	54.22	55.77	56.73	57.63	58.44
8,910,843.34	9,877,790.93	13,444,918.11	8,910,843.34	7,179,393.39	9,908,556.67	6,438,208.15
28,637,936.60	31,428,941.16	41,734,490.72	28,637,936.60	23,609,691.57	31,487,041.11	21,472,887.18
5,717,405.12	5,715,314.97	5,614,439.85	5,717,405.12	5,715,314.97	5,614,439.85	5,717,405.12
6,006,823.83	5,937,533.67	5,684,953.47	6,006,823.83	5,937,533.67	5,684,953.47	6,006,823.83

10	11	12	13	14	15	16
Alkaline Electrolyzer H2 to Methanator; CH4 Injected into Transmission Pipeline	**Solid Oxide Electrolyzer H2 to Methanator; CH4 Injected into Transmission Pipeline**	**PEM Electrolyzer H2 to Methanator; CH4 Injected into Transmission Pipeline**	**Alkaline Electrolyzer H2 into PEM Fuel Cell; MWh Delivered into Electric Grid**	**Solid Oxide Electrolyzer H2 into PEM Fuel Cell; MWh Delivered into Electric Grid**	**PEM Electrolyzer H2 into PEM Fuel Cell; MWh Delivered into Electric Grid**	**Alkaline Electrolyzer H2 into PAFC Fuel Cell; MWh Delivered into Electric Grid**
522.19	821.29	705.87	2,223.50	2,367.43	2,538.42	2,922.15
13.76	20.32	18.91	53.07	55.95	64.37	67.08
1.57	16.39	0.22	15.69	34.44	13.41	10.61
73.73	73.65	73.76	79.55	79.38	78.44	79.55
86.65	86.41	86.72	89.02	89.07	89.25	89.02
31,519,870.20	31,738,063.30	31,466,985.35	17,709,863.33	17,991,720.31	19,922,237.25	17,709,863.33
16,577,214.28	17,240,531.86	16,413,011.42	1,882,417.80	1,874,690.63	1,879,401.80	1,882,417.80
52.62	53.65	53.80	58.44	59.45	59.72	61.84
56.90	57.81	58.62	83.87	85.45	85.38	89.43
7,179,393.39	9,908,556.67	6,438,208.15	11,498,371.95	11,216,514.97	9,285,998.03	11,498,371.95
23,609,691.57	31,487,041.11	21,472,887.18	10,801,972.81	10,809,699.98	10,804,988.81	10,801,972.81
5,715,314.97	5,614,439.85	5,717,405.12	216,483.66	154,954.98	124,508.03	216,483.66
5,937,533.67	5,684,953.47	6,006,823.83	80,336,594.33	78,789,763.90	71,400,405.83	80,336,594.33

17	18	19	20	21	22	23
Solid Oxide Electrolyzer H2 into PAFC Fuel Cell; MWh Delivered into Electric Grid	**PEM Electrolyzer H2 into PAFC Fuel Cell; MWh Delivered into Electric Grid**	**Alkaline Electrolyzer H2 into MCFC Fuel Cell; MWh Delivered into Electric Grid**	**Solid Oxide Electrolyzer H2 into MCFC Fuel Cell; MWh Delivered into Electric Grid**	**PEM Electrolyzer H2 into MCFC Fuel Cell; MWh Delivered into Electric Grid**	**Alkaline Electrolyzer H2 into SOFC Fuel Cell; MWh Delivered into Electric Grid**	**Solid Oxide Electrolyzer H2 into SOFC Fuel Cell; MWh Delivered into Electric Grid**
3,066.07	3,236.63	2,137.21	2,281.13	2,451.69	1,958.53	2,102.45
69.95	78.37	51.38	54.25	62.67	47.81	50.67
29.36	8.33	7.82	26.57	5.54	5.27	24.02
79.38	78.44	79.55	79.38	78.44	79.55	79.38
89.07	89.25	89.02	89.07	89.25	89.02	89.07
17,991,720.31	19,922,237.25	17,709,863.33	17,991,720.31	19,922,237.25	17,709,863.33	17,991,720.31
1,874,690.63	1,879,401.80	1,882,417.80	1,874,690.63	1,879,401.80	1,882,417.80	1,874,690.63
62.84	63.09	57.88	58.89	59.16	56.93	57.95
90.99	90.86	83.00	84.57	84.52	81.45	83.03
11,216,514.97	9,285,998.03	11,498,371.95	11,216,514.97	9,285,998.03	11,498,371.95	11,216,514.97
10,809,699.98	10,804,988.81	10,801,972.81	10,809,699.98	10,804,988.81	10,801,972.81	10,809,699.98
154,954.98	124,508.03	216,483.66	154,954.98	124,508.03	216,483.66	154,954.98
78,789,763.90	71,400,405.83	80,336,594.33	78,789,763.90	71,400,405.83	80,336,594.33	78,789,763.90

24	25	26	27	28	29	30
PEM Electrolyzer H2 into SOFC Fuel Cell; MWh Delivered into Electric Grid	**ZnBr Flow Battery**	**Li-Ion Battery**	**Advanced Lead-Acid Battery**	**Sodium-Sulfur Battery**	**Alkaline Central Plant Electrolyzer; Gaseous H2 Trucked to H2 Fueling Station**	**Solid Oxide Central Plant Electrolyzer; Gaseous H2 Trucked to H2 Fueling Station**
2,273.01	312.44	1,327.87	2,000.75	2,524.35	289.62	466.60
59.10	77.65	307.78	101.42	4.86	10.43	15.40
2.99	0.61	2.78	0.63	0.47	1.24	13.00
78.44	80.36	82.21	82.15	81.13	71.69	71.57
89.25	87.78	86.56	86.62	87.28	84.58	84.39
19,922,237.25	12,196,886.34	8,047,748.96	8,204,352.09	10,406,241.41	36,146,552.19	36,438,487.61
1,879,401.80	1,911,583.34	1,880,001.31	1,854,575.20	1,909,538.20	20,451,739.81	21,018,692.68
58.23	57.06	71.78	67.64	65.88	49.88	50.38
83.00	80.92	109.59	102.17	97.66	55.75	56.16
9,285,998.03	17,011,348.94	21,160,486.32	21,003,883.19	18,801,993.87	39,285,415.73	53,347,858.82
10,804,988.81	10,772,807.26	10,804,389.29	10,829,815.40	10,774,852.41	103,169,609.13	137,053,164.69
124,508.03	16,986,008.52	26,127,761.49	25,748,416.87	20,866,216.70	2,934,764.18	2,843,016.99
71,400,405.83	126,665,042.29	160,711,072.33	159,414,601.10	141,231,382.68	17,311,284.16	16,773,837.37

31	32	33	34	35	36	37
PEM Central Plant Electrolyzer; Gaseous H2 Trucked to H2 Fueling Station	**Alkaline Central Plant Electrolyzer; Liquid H2 Trucked to H2 Fueling Station**	**Solid Oxide Central Plant Electrolyzer; Liquid H2 Trucked to H2 Fueling Station**	**PEM Central Plant Electrolyzer; Liquid H2 Trucked to H2 Fueling Station**	**Alkaline Onsite Elecrolyzer; Gaseous H2 Generated at H2 Fueling Station**	**Solid Oxide Onsite Elecrolyzer; Gaseous H2 Generated at H2 Fueling Station**	**PEM Onsite Elecrolyzer; Gaseous H2 Generated at H2 Fueling Station**
398.30	289.62	466.60	398.30	289.62	466.60	398.30
14.32	10.43	15.40	14.32	10.43	15.40	14.32
0.17	1.24	13.00	0.17	1.24	13.00	0.17
71.71	71.69	71.57	71.71	71.69	71.57	71.71
84.63	84.58	84.39	84.63	84.58	84.39	84.63
36,068,763.75	36,146,552.19	36,438,487.61	36,068,763.75	36,146,552.19	36,438,487.61	36,068,763.75
20,290,565.42	20,451,739.81	21,018,692.68	20,290,565.42	20,451,739.81	21,018,692.68	20,290,565.42
50.57	50.01	50.60	50.68	50.10	50.75	50.75
56.82	55.97	56.52	57.01	56.12	56.76	57.13
35,495,879.92	39,285,415.73	53,347,858.82	35,495,879.92	39,285,415.73	53,347,858.82	35,495,879.92
94,049,205.33	103,169,609.13	137,053,164.69	94,049,205.33	103,169,609.13	137,053,164.69	94,049,205.33
2,962,677.23	2,934,764.18	2,843,016.99	2,962,677.23	2,934,764.18	2,843,016.99	2,962,677.23
17,441,522.21	17,311,284.16	16,773,837.37	17,441,522.21	17,311,284.16	16,773,837.37	17,441,522.21

38	39	40	41	42	43	44
Immediate, Level III	Immediate, Level II	Immediate, Level 1	Smart, Level III	Smart, Level II	Smart, Level 1	V2G, Level III
1,309.00	1,322.22	1,428.00	1,309.00	1,322.22	1,428.00	1,309.00
95.20	66.11	83.30	95.20	66.11	83.30	95.20
0.00	0.00	0.00	0.00	0.00	0.00	0.00
59.23	60.10	59.51	65.64	63.05	61.19	70.69
56.40	62.99	62.50	74.03	69.91	66.49	84.85
64,476,750.10	59,238,548.88	58,877,503.86	45,101,823.58	49,637,852.63	52,871,883.18	35,417,345.37
94,912,188.83	77,271,846.23	75,235,093.10	44,327,024.67	53,962,564.28	61,305,324.51	17,821,801.45
63.39	52.51	51.66	52.96	51.41	51.22	48.24
98.53	74.72	73.35	75.36	71.99	72.23	58.17
57,818,417.20	63,056,618.43	63,417,663.45	77,193,425.60	72,657,428.21	69,423,313.87	99,182,165.40
171,809,442.08	189,449,784.69	191,486,537.82	222,394,606.25	212,759,066.64	205,416,168.04	269,879,912.15
57,046,010.43	53,807,564.85	56,485,924.51	30,213,020.78	41,357,578.69	49,511,827.76	925,726.30
166,435,478.46	139,262,695.13	142,104,107.30	78,907,058.20	101,574,063.20	120,462,343.60	6,157,397.94

45	46
V2G, Level II	V2G, Level 1
1,322.22	1,428.00
66.11	83.30
0.00	0.00
70.76	67.23
84.08	77.93
34,160,581.42	39,329,184.50
17,808,376.39	31,779,154.62
50.49	51.73
58.99	59.90
92,673,849.44	75,342,976.88
243,543,955.30	226,107,088.06
5,678,172.16	28,664,980.08
28,516,102.20	63,848,695.49

Task 4 Technology Parameters – 2045 Base Case

The following tables display the economic and technical parameters that were used in the optimization to determine the technology portfolio.

Table C37: The economic assumptions for renewable generation.

Technology Description	PV, 1-Axis	PV, 2-Axis	Geo-Binary	Geo-Flash	Wind
Instant Cost ($/kW)	1,084.00	715.00	4,878.00	3,781.00	1,183.00
FOM ($/kW-yr)	9.00	9.00	178.00	135.00	35.00
Reference	[314]	[314]	[314]	[314]	[314]

Table C38: Economic and technological assumptions for electrolyzer and hydrogen storage technologies.

Technology Description	Alkaline Electrolyzer	Solid Oxide Electrolyzer	PEM Electrolyzer	Onsite H2 Pressure Vessel Storage	Geologic (Underground) H2 Storage
Instant Cost ($/kW)	402.00	600.50	505.00	19.08	5.14
FOM ($/kW-yr)	7.04	10.51	8.84	-	-
VOM ($/MWh)	1.24	13.00	0.17		
Efficiency (kWh/kg)	56.78	44.46	56.78		
Reference	[263], [308]	[263], [308]	[263], [308]	[278], [280]	[278], [280]

Table C39: Economic and technological assumptions for fuel cell technologies.

Technology Description	PEM Fuel Cell	PAFC Fuel Cell	MCFC Fuel Cell	SOFC Fuel Cell
Instant Cost ($/kW)	813.00	2,226.07	1,441.13	615.91
FOM ($/kW-yr)	30.55	44.52	28.82	25.25
VOM ($/MWh)	13.00	7.92	5.13	2.58
Efficiency (MMBtu H2/MWh)	6.20	7.58	5.69	4.74
Reference	[263], [279], [315], [316]	[263], [279], [315]	[263], [279], [315]	[263], [279], [315], [316]

Table C40: Economic and technological assumptions for non-hydrogen energy storage technologies.

Technology Description	ZnBr Flow Battery	Li-Ion Battery	Pumped Hydro	Compressed Air
Instant Cost ($/kW)	312.44	658.00	-	1,250.00
FOM ($/kW-yr)	77.65	16.46	35.00	24.60
VOM ($/MWh)	0.61	2.78	7.00	65.00
Efficiency (%)	65%	90%	80%	52%

Reference	[317], [318], [319]	[314], [317], [318], [319], [320]	[317], [318], [319]	[317], [318], [319]

Task 4 Technology Parameters – 2030 Base Case

The following tables display the economic and technical parameters that were used in the optimization to determine the technology portfolio. This is data is also used in the multi-year analysis.

Table C41: The economic assumptions for renewable generation.

Technology Description	PV, 1-Axis	PV, 2-Axis	Geo-Binary	Geo-Flash	Wind	NGPP-CT	NGPP-CC
Instant Cost ($/kW)	1,124	819	5,300	3,831	1,175	862.00	944.00
FOM ($/kW-yr)	8.43	9.80	178.00	127.00	39.00	11.00	13.00
VOM ($/MWh)	-	-	-	-	-	4.00	2.00
Reference	[314]	[314]	[314]	[314]	[314]	[314]	[314]

Table C42: Economic and technological assumptions for electrolyzer and hydrogen storage technologies.

Technology Description	Alkaline Electrolyzer	Solid Oxide Electrolyzer	PEM Electrolyzer	Onsite H2 Pressure Vessel Storage	Geologic (Underground) H2 Storage
Instant Cost ($/kW)	748.50	1,736.33	1126	15.8	4.92
FOM ($/kW-yr)	13.10	30.39	19.70	-	-

VOM ($/MWh)	1.31	13.71	0.18		
Efficiency (kWh/kg)	56	50	56		
Reference	[263], [308]	[263], [308]	[263], [308]	[278], [280]	[278], [280]

Table C43: Economic and technological assumptions for fuel cell technologies.

Technology Description	PEM Fuel Cell	PAFC Fuel Cell	MCFC Fuel Cell	SOFC Fuel Cell
Instant Cost ($/kW)	824.00	1917.00	1,241.00	625.00
FOM ($/kW-yr)	36.37	71.29	46.15	28.60
VOM ($/MWh)	13.00	7.92	5.13	2.58
Efficiency (MMBtu H2/MWh)	6.70	7.80	5.95	5.42
Reference	[263], [279], [315], [316]	[263], [279], [315]	[263], [279], [315]	[263], [279], [315], [316]

Table C44: Economic and technological assumptions for non-hydrogen energy storage technologies.

Technology Description	ZnBr Flow Battery	Li-Ion Battery	Pumped Hydro	Compressed Air
Instant Cost ($/kW)	721.00	817.00	-	1,250.00
FOM ($/kW-yr)	50.32	20.43	35.00	24.60

VOM ($/MWh)	0.61	2.78	7.00	65.00
Efficiency (%)	63%	85%	80%	52%
Reference	[317], [318], [319]	[314], [317], [318], [319], [320]	[317], [318], [319]	[317], [318], [319]

Task 5 Technology Parameters – 2045 Updated

The following tables display the economic and technical parameters that were used in the optimization to determine the technology portfolio, using the updated values from the NREL ATB 2020 data. This is data is also used in the multi-year analysis.

Table C45: The economic assumptions for renewable generation.

Technology Description	**PV, 1-Axis**	**PV, 2-Axis**	**Geo-Binary**	**Geo-Flash**	**Wind**
Instant Cost ($/kW)	836.00	710.00	4,917.00	3,781.00	1,029
FOM ($/kW-yr)	6.00	8.00	173.00	135.00	35.00
Reference	[314]	[314]	[314]	[314]	[314]

Table C46: Economic and technological assumptions for electrolyzer and hydrogen storage technologies.

Technology Description	**Alkaline Electrolyzer**	**Solid Oxide Electrolyzer**	**PEM Electrolyzer**	**Onsite H2 Pressure Vessel Storage**	**Geologic (Underground) H2 Storage**
Instant Cost ($/kW)	402.00	600.50	505.00	11.20	4.15

FOM ($/kW-yr)	7.04	10.51	8.84	-	-
VOM ($/MWh)	1.24	13.71	0.18		
Efficiency (kWh/kg)	53	47	53		
Reference	[263], [308]	[263], [308]	[263], [308]	[278], [280]	[278], [280]

Table C47: Economic and technological assumptions for fuel cell technologies.

Technology Description	PEM Fuel Cell	PAFC Fuel Cell	MCFC Fuel Cell	SOFC Fuel Cell
Instant Cost ($/kW)	551.00	1270.00	828.00	417.00
FOM ($/kW-yr)	30.55	44.52	28.82	25.25
VOM ($/MWh)	13	7.92	5.13	2.58
Efficiency (MMBtu H2/MWh)	6.20	7.58	5.69	4.74
Reference	[263], [279], [315], [316]	[263], [279], [315]	[263], [279], [315]	[263], [279], [315], [316]

Table C48: Economic and technological assumptions for non-hydrogen energy storage technologies.

Technology Description	ZnBr Flow Battery	Li-Ion Battery	Pumped Hydro	Compressed Air
Instant Cost ($/kW)	312.44	658.00	-	1,250.00

FOM ($/kW-yr)	22.99	16.46	35.00	24.60
VOM ($/MWh)	0.61	2.78	7.00	65.00
Efficiency (%)	63%	85%	80%	52%
Reference	[317], [318], [319]	[314], [317], [318], [319], [320]	[317], [318], [319]	[317], [318], [319]

Task 6 Technology Parameters – 2035 & 2040

The following tables display the economic and technical parameters that were used in the optimization to determine the technology portfolio.

2035 Parameters:

Table C49: The economic assumptions for renewable generation.

Technology Description	**PV, 1-Axis**	**PV, 2-Axis**	**Geo-Binary**	**Geo-Flash**	**Wind**	**NGP P-CT**	**NGP P-CC**
Instant Cost ($/kW)	954.00	782.00	5,169.00	3,781.00	1,128.00	844.00	925.00
FOM ($/kW-yr)	7.00	9.00	173.00	135.00	37.00	11.00	13.00
VOM ($/MWh)	-	-	-	-	-	4.00	2.00
Reference	[314]	[314]	[314]	[314]	[314]	[314]	[314]

Table C50: Economic and technological assumptions for electrolyzer and hydrogen storage technologies.

Technology Description	Alkaline Electrolyzer	Solid Oxide Electrolyzer	PEM Electrolyzer	Onsite H2 Pressure Vessel Storage	Geologic (Underground) H2 Storage
Instant Cost ($/kW)	612.50	893.50	929.00	14.288	4.66
FOM ($/kW-yr)	10.72	15.64	16.26	-	-
VOM ($/MWh)	1.31	13.71	0.18		
Efficiency (kWh/kg)	55	51	57		
Reference	[263], [308]	[263], [308]	[263], [308]	[278], [280]	[278], [280]

Table C51: Economic and technological assumptions for fuel cell technologies.

Technology Description	PEM Fuel Cell	PAFC Fuel Cell	MCFC Fuel Cell	SOFC Fuel Cell
Instant Cost ($/kW)	733.00	1705.00	1103.00	556.00
FOM ($/kW-yr)	34.43	62.37	40.38	27.49
VOM ($/MWh)	13.00	7.92	5.13	2.58
Efficiency (MMBtu H2/MWh)	6.20	7.58	5.69	4.74
Reference	[263], [279], [315], [316]	[263], [279], [315]	[263], [279], [315]	[263], [279], [315], [316]

Table C52: Economic and technological assumptions for non-hydrogen energy storage technologies.

Technology Description	ZnBr Flow Battery	Li-Ion Battery	Pumped Hydro	Compressed Air
Instant Cost ($/kW)	585.00	766.00	-	1,250.00
FOM ($/kW-yr)	22.99	19.15	35.00	24.60
VOM ($/MWh)	0.61	2.78	7.00	65.00
Efficiency (%)	63%	85%	80%	52%
Reference	[317], [318], [319]	[314], [317], [318], [319], [320]	[317], [318], [319]	[317], [318], [319]

2040 Parameters:

Table C53: The economic assumptions for renewable generation.

Technology Description	PV, 1-Axis	PV, 2-Axis	Geo-Binary	Geo-Flash	Wind	NGPP-CT	NGPP-CC
Instant Cost ($/kW)	895.00	746.00	5,041.00	3,781.00	1,079	830.00	910.00
FOM ($/kW-yr)	7.00	9.00	173.00	135.00	36.00	11.00	13.00
VOM ($/MWh)	-	-	-	-	-	4.00	2.00
Reference	[314]	[314]	[314]	[314]	[314]	[314]	[314]

Table C54: Economic and technological assumptions for electrolyzer and hydrogen storage technologies.

Technology Description	Alkaline Electrolyzer	Solid Oxide Electrolyzer	PEM Electrolyzer	Onsite H2 Pressure Vessel Storage	Geologic (Underground) H2 Storage
Instant Cost ($/kW)	503.00	676.00	756.00	12.74	4.41
FOM ($/kW-yr)	8.80	11.82	13.22	-	-
VOM ($/MWh)	1.31	13.71	0.18	-	-
Efficiency (kWh/kg)	54	48	55	-	-
Reference	[263], [308]	[263], [308]	[263], [308]	[278], [280]	[278], [280]

Table C55: Economic and technological assumptions for fuel cell technologies.

Technology Description	PEM Fuel Cell	PAFC Fuel Cell	MCFC Fuel Cell	SOFC Fuel Cell
Instant Cost ($/kW)	642.00	1492.00	966.00	486.00
FOM ($/kW-yr)	32.50	53.45	34.60	26.37
VOM ($/MWh)	13.00	7.92	5.13	2.58
Efficiency (MMBtu H2/MWh)	6.20	7.58	5.69	4.74

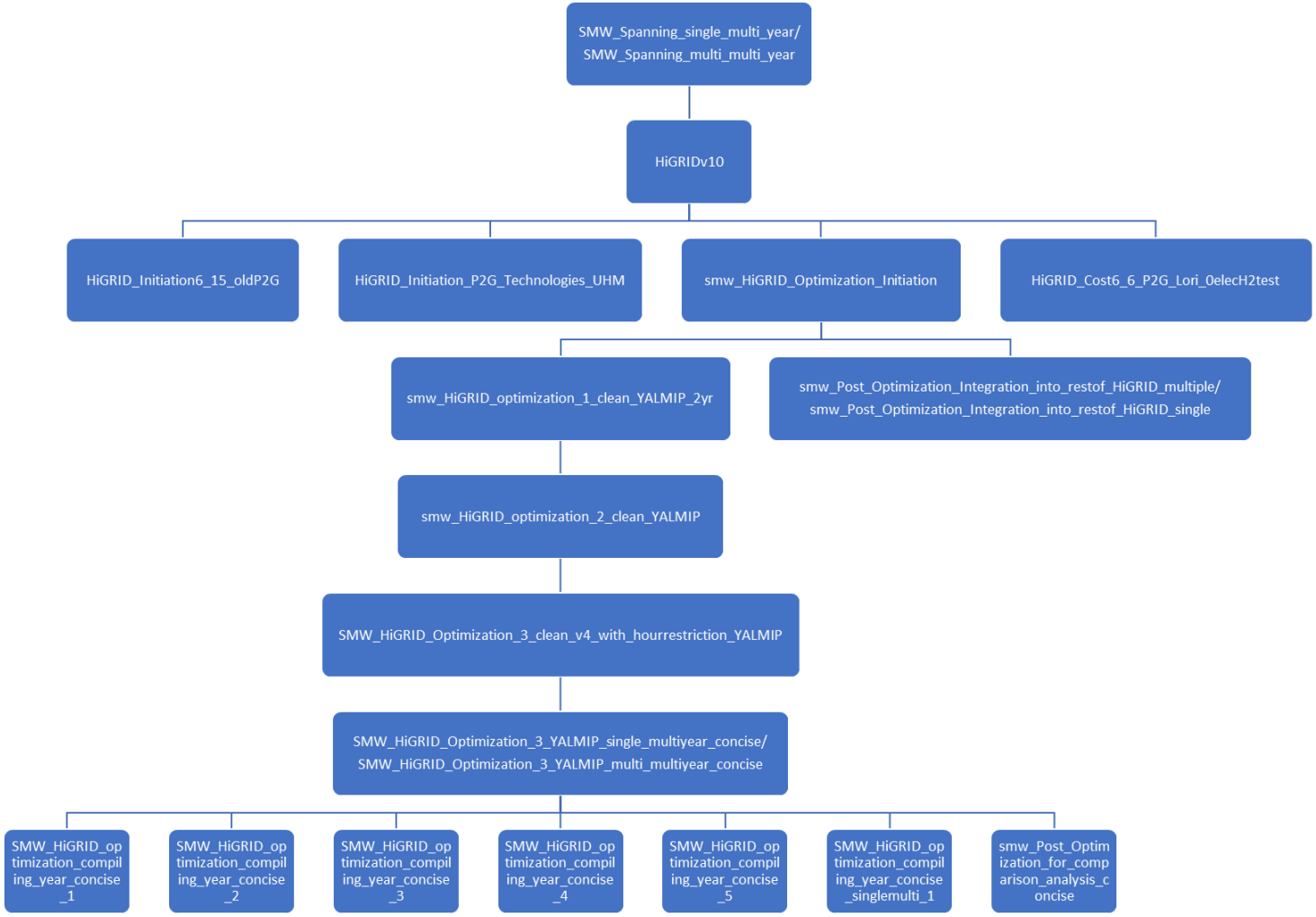
Reference	[263], [279], [315], [316]	[263], [279], [315]	[263], [279], [315]	[263], [279], [315], [316]

Table C56: Economic and technological assumptions for non-hydrogen energy storage technologies.

Technology Description	ZnBr Flow Battery	Li-Ion Battery	Pumped Hydro	Compressed Air
Instant Cost ($/kW)	448.00	715.00	-	1,250.00
FOM ($/kW-yr)	22.99	17.88	35.00	24.60
VOM ($/MWh)	0.61	2.78	7.00	65.00
Efficiency (%)	63%	85%	80%	52%
Reference	[317], [318], [319]	[314], [317], [318], [319], [320]	[317], [318], [319]	[317], [318], [319]

APPENDIX D

The order of matlab.m files:



For future use of the optimization model and HiGRID see the following descriptions of the Matlab scripts:

1. SMW_Spanning_single_multi_year & SMW_Spanning_multi_multi_year
    a. The differences between these two Matlab scripts are whether the optimization is ran to simulate a single representative year or to run multiple representative years. This file will initialize the demands and years ran.
2. HiGRIDv10
    a. This is the main HiGRID Matlab script that determines the renewable generation and net load.
    b. Within the script, the calculation for the cost of renewable generation is determined. The toggle smw_two_yr_analysis to equal 1.
3. HiGRID_Initiation6_15_oldP2G
    a. Initializes the g-matrix
4. HiGRID_Parameters_P2G_Technologies_UHM
    a. Initializes the chosen technologies for the analysis
5. smw_HiGRID_Optimization_Initiation
    a. Initializes the optimization to run
    b. The smw_Post_Optimization_Integration_into_restof_HiGRID_multiple/single is also ran from here after the optimization
        i. Populates the p-matrix and translate optimization variables to HiGRID variables, such as CURT to Ptrans
6. smw_HiGRID_optimization_1_clean_YALMIP_2yr
    a. adds the paths to CPLEX and YALMIP
    b. translate the technology parameters from the g-matrix to variables to be used in the optimization
    c. The Shadow Price portion is for the sensitivity analysis
7. smw_HiGRID_optimization_2_clean_YALMIP
    a. determines the hourly profiles and demands
        i. smw_Renewables_init_HiGRID_2 is the availability of ERE
        ii. GTGEN_init_HiGRID is the net load demand
        iii. FCV_H2_Demand_init is the hourly hydrogen demand for vehicles
        iv. smw_EV_charging_init is the hourly charging demand for vehicles
        v. Gas_V_init is the hourly fueling gasoline demand for vehicles
        vi. NG_NG_Demand_init is the hourly non-electric natural gas demand
        vii. C_CA_factor is the cost of carbon
8. SMW_HiGRID_Optimization_3_clean_v4_with_hourrestriction_YALMIP
    a. Determines whether to run the single, multi-year run or the multi, multi-year run
9. SMW_HiGRID_Optimization_3_YALMIP_single_multiyear_concise/SMW_HiGRID_Optimization_3_YALMIP_multi_multiyear_concise
    a. This is where the optimization constraints and objective function are compiled and the CPLEX optimization is run

    b. Depending on whether the optimization is running one single year or multiple years determines which exact matlab file is ran
10. SMW_HiGRID_optimization_compiling_year_concise1/2/3/4/5/singlemulti_1
    a. Translates the optimization results (which are not readable without imposing the function value(*variable*))
    b. The singlemulti_1 represents the single_multiyear run
    c. Each number 1/2/3/4/5 represents each year of the multirun
        i. Only the years that are considered are ran
11. smw_Post_Optimization_for_comparison_analysis_concise
    a. Saves the annual variables that are of use, these are later saved into a matrix in the SMW_Spanning_single_multi_year or SMW_Spanning_multi_multi_year
12. smw_Post_Optimization_Integration_into_restof_HiGRID_single/ smw_Post_Optimization_Integration_into_restof_HiGRID_multiple
    a. Populates the p-matrix and sets some of the costs/efficiencies as needed