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Advising and Optimizing the Deployment of Sustainability-Oriented Technologies in the
Integrated Electricity, Light-Duty Transportation, and Water Supply System

DISSERTATION

submitted in partial satisfaction of the requirements
for the degree of

DOCTOR OF PHILOSOPHY

in Mechanical and Aerospace Engineering

by

Brian Tarroja

Dissertation Committee:
Professor Scott Samuelson, Chair
Professor Donald Dabdub
Professor David Feldman

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ABSTRACT OF THE DISSERTATION

Advising and Optimizing the Deployment of Sustainability-Oriented Technologies in the
Integrated Electricity, Light-Duty Transportation, and Water Supply System

By

Brian Tarroja

Doctor of Philosophy in Mechanical and Aerospace Engineering

University of California, Irvine, 2014

Professor Scott Samuelsen, Chair

The convergence of increasing populations, decreasing primary resource availability, and uncertain climates have drawn attention to the challenge of shifting the operations of key resource sectors towards a sustainable paradigm. This is prevalent in California, which has set sustainability-oriented policies such as the Renewable Portfolio Standards and Zero-Emission Vehicle mandates. To meet these goals, many options have been identified to potentially carry out these shifts. The electricity sector is focusing on accommodating renewable power generation, the transportation sector on alternative fuel drivetrains and infrastructure, and the water supply sector on conservation, reuse, and unconventional supplies. Historical performance evaluations of these options, however, have not adequately taken into account the impacts on and constraints of co-dependent infrastructures that must accommodate them and their interactions with other simultaneously deployed options. These aspects are critical for optimally choosing options to meet sustainability goals, since the combined system of all resource sectors must satisfy them. Certain operations should not be made sustainable at the expense of rendering

others as unsustainable, and certain resource sectors should not meet their individual goals in a way that hinders the ability of the entire system to do so. Therefore, this work develops and utilizes an integrated platform of the electricity, transportation, and water supply sectors to characterize the performance of emerging technology and management options while taking into account their impacts on co-dependent infrastructures and identify synergistic or detrimental interactions between the deployment of different options. This is carried out by first evaluating the performance of each option in the context of individual resource sectors to determine infrastructure impacts, then again in the context of paired resource sectors (electricity-transportation, electricity-water), and finally in the context of the combined tri-sector system. This allows a more robust basis for composing preferred option portfolios to meet sustainability goals and gives a direction for coordinating the paradigm shifts of different resource sectors. Overall, it is determined that taking into account infrastructure constraints and potential operational interactions can significantly change the evaluation of the preferred role that different technologies should fulfill in contributing towards satisfying sustainability goals in the holistic context.

Chapter 1: Introduction

1.1. Driving Forces

Due to the industrial revolutions that have currently or previously taken place in different parts of the world, societies in those areas have embarked on a trend of increasing energy consumption. Increases in societal quality of life have historically been linked with an increasing reliance on energy-intensive services, goods, and supporting infrastructure. The desire for increasing quality of life combined with population growth has brought societal energy usage to a tipping point, where the methods that are currently used to meet quality of life goals have begun to have detrimental effects on environmental quality and the availability of limited resources. These effects can have consequences for human health and ultimately society's ability to create and maintain an adequate quality of life standard for its citizens in the near and far future. The realization of these trends has motivated attention for evaluating the sustainability of current and future societal operations. A brief description of the specifics of these converging trends is presented here.

1.1.1. Growing Service and Related Resource Demands

The first primary driving force for sustainability studies is the projected growth in the demand for primary resources which enable societal function and certain standards for quality of life. The nature of growing demands for different services and the resources that enable them is presented here.

1.1.1.1. Growing Demand for Electricity

Electric energy is one of the key forms of energy which enables the development and operation of essentially every industry. Increased utilization of electric energy has historically been a central aspect of the ability of a population to improve their quality of life and maintain it at

desired levels. This relationship is especially pronounced for many developing nations such as China and India, which contain large populations and whose citizens seek to increase their quality of life. The world electricity demand is expected to double by 2035 as compared to 2007 levels, from 18.8 trillion kWh to approximately 35.2 trillion kWh, with the breakdown of the growth displayed in Table 1:

Table 1- OECD and Non-OECD net electricity generation by source, 2007-2035 (trillion kWh) [1]

<u>Region</u>	2007	2015	2020	2025	2030	2035	Avg. Annual % Change 2007-2035
OECD							
Liquids	0.3	0.3	0.3	0.3	0.3	0.2	-1.0
Natural Gas	2.2	1.9	2.2	2.5	2.9	3.1	1.4
Coal	3.9	3.8	3.8	3.8	4.0	4.2	0.3
Nuclear	2.2	2.4	2.5	2.6	2.7	2.8	1.0
Renewables	1.6	2.3	2.6	2.9	3.1	3.2	2.5
Total OECD	10.1	10.7	11.4	12.2	12.9	13.6	1.1
Non-OECD							
Liquids	0.6	0.6	0.5	0.5	0.5	0.6	-0.2
Natural Gas	1.7	2.2	2.8	3.2	3.6	3.7	2.8
Coal	4.1	5.1	6.0	7.3	9.0	10.8	3.6
Nuclear	0.4	0.7	1.0	1.3	1.5	1.7	5.0
Renewables	1.8	2.7	3.2	3.7	4.3	4.8	3.5
Total Non-OECD	8.6	11.2	13.6	16.1	18.8	21.6	3.3
World							
Liquids	0.9	0.9	0.8	0.8	0.8	0.8	-0.4
Natural Gas	3.9	4.2	5.0	5.8	6.4	6.8	2.1
Coal	7.9	8.8	9.8	11.2	12.9	15.0	2.3
Nuclear	2.6	3.1	3.6	3.9	4.2	4.5	2.0
Renewables	3.5	5.0	5.8	6.6	7.3	8.0	3.0
Total World	18.8	21.9	25.0	28.3	31.6	35.2	2.3

Of the increase in electricity demand, China alone is expected to compose approximately 29.8% of the total electricity demand by 2035, amounting to about 10.5 trillion kWh (compared to about 3.0 trillion kWh in 2007) [1]. Developing countries as a collective are projected to compose 61.3% of the total electricity demand by 2035. Such a trend makes sense since the developing countries in general exhibit high birth rates compounding on already large populations. In addition, many such countries are currently undergoing a widespread industrial revolution

similar to that which took place in the United States in the 19th century, albeit at a much larger scale with more energy intensive technologies, as a means to improve their quality of life. Therefore, not only is the amount of electricity consumers expected to increase, the electricity use per capita in many countries is expected to increase as well. By contrast, many of the developed countries in the OECD are expected to exhibit only a relatively small increase in electricity demand by 2035, primarily due to lower birth rates and smaller changes in the energy intensity of goods and services relied upon by their respective societies. In order to ensure that the increase in demand is fulfilled, these trends and projections are summarized in Figure 1:

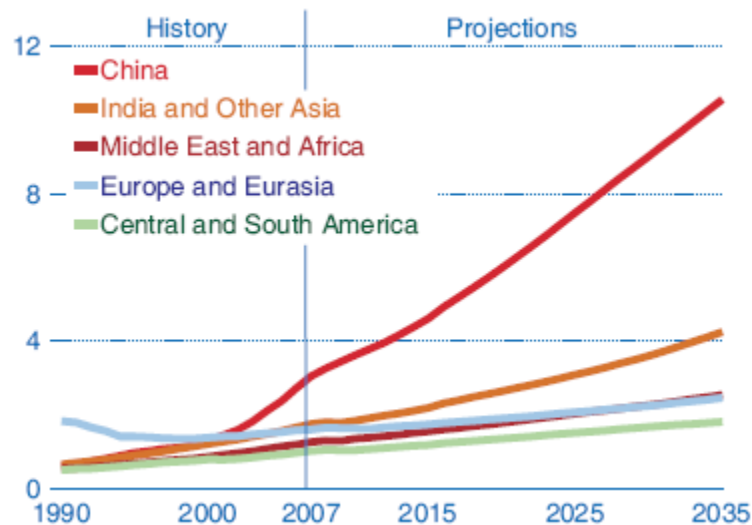


Figure 1 - Non-OECD net electricity generation by region, 1990 -2035 (trillion kWh) [2]

Although the OECD countries including the U.S. are not expected to exhibit as large of a growth in electricity demand as the developing nations, these countries are still expected to contribute to the increased demand for electricity. In the U.S., the total electricity demand is projected to increase at an average rate of 1.0% annually from 2008 levels through 2035, an approximate increase from 3.873 trillion kWh to 5.021 trillion kWh [2]. Therefore, the net electricity

generation capacity must increase not just at the rate of the demand increase, but at a higher rate due to reliability criteria for the electric grid, as shown in Figure 2:

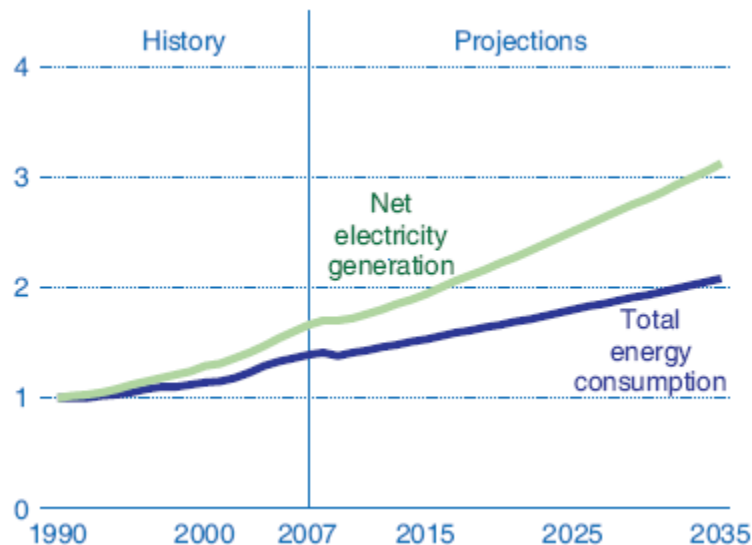


Figure 2 - U.S. Net electricity generation capacity and Electricity Consumption, 1990 - 2035. 1990 Levels are referenced as equal to an index of 1 [2]

For the U.S., the growth in demand is primarily due to population growth and population shifts to areas with higher cooling requirements, as well as the rapid development of the commercial sector and service oriented industries.

If historical trends are followed, increases in the demand for electric energy imply increases in the use of primary energy resources that are converted to provide usable electric energy. This has serious implications for the ability of our societies to create and sustain desired quality of life standards for their citizens. The historical composition of the electric grid resource mix has typically been composed of fossil fuels, the conversion of which to electric energy produces emissions of greenhouse gases which exacerbate climate change effects and air pollutants which pose human health risks. The primary energy flow for the production of electricity in the U.S. in 2011 is presented in Figure 3 [3]. This display is used because it presents primary energy

consumption by source rather than generation, the latter of which is filtered by the efficiency of the conversion technologies which can vary widely.

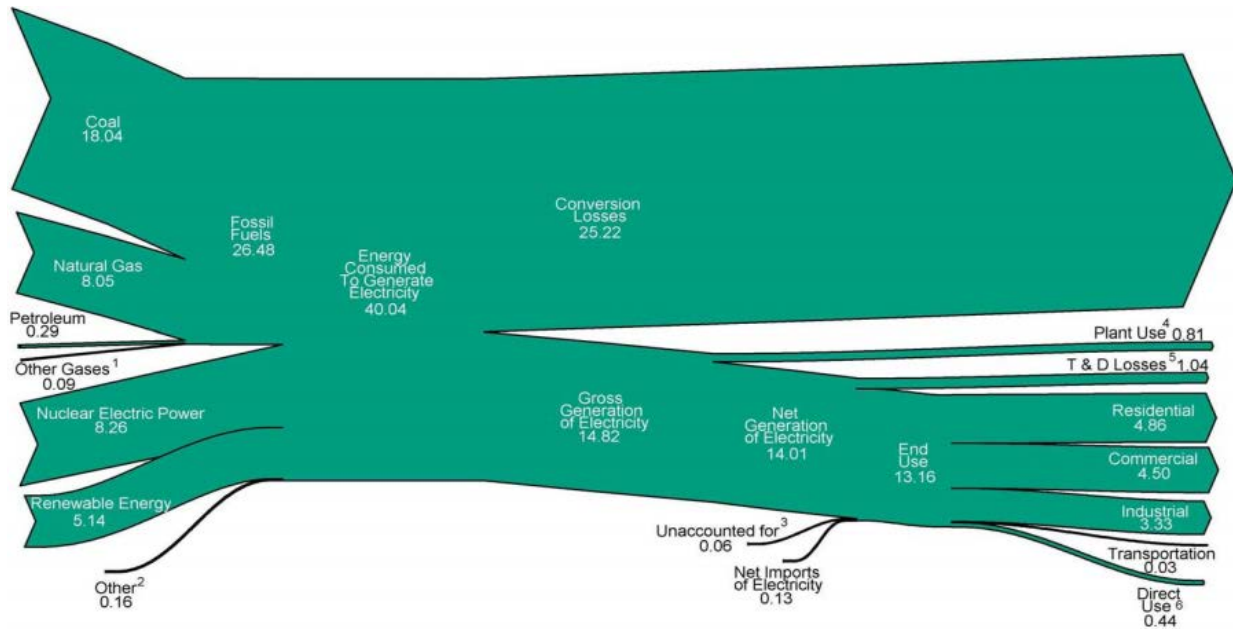


Figure 3 - Primary Energy Flow for the Production of Electricity in the U.S. in 2011 in Quadrillion BTU [3]

Fossil fuels composed about 66.1% of the primary energy consumption for electricity production, with 45.0% being composed of coal alone. Coal has been used widely due to large available reserves and low prices which give rise to lower costs of electricity, although the use of natural gas has been increasing due to the extraction of low-cost shale gas. This mix has given rise to a large contribution to greenhouse gas emissions from the electricity sector, as presented for the U.S. from 1991-2011 in Figure 4 [4]:

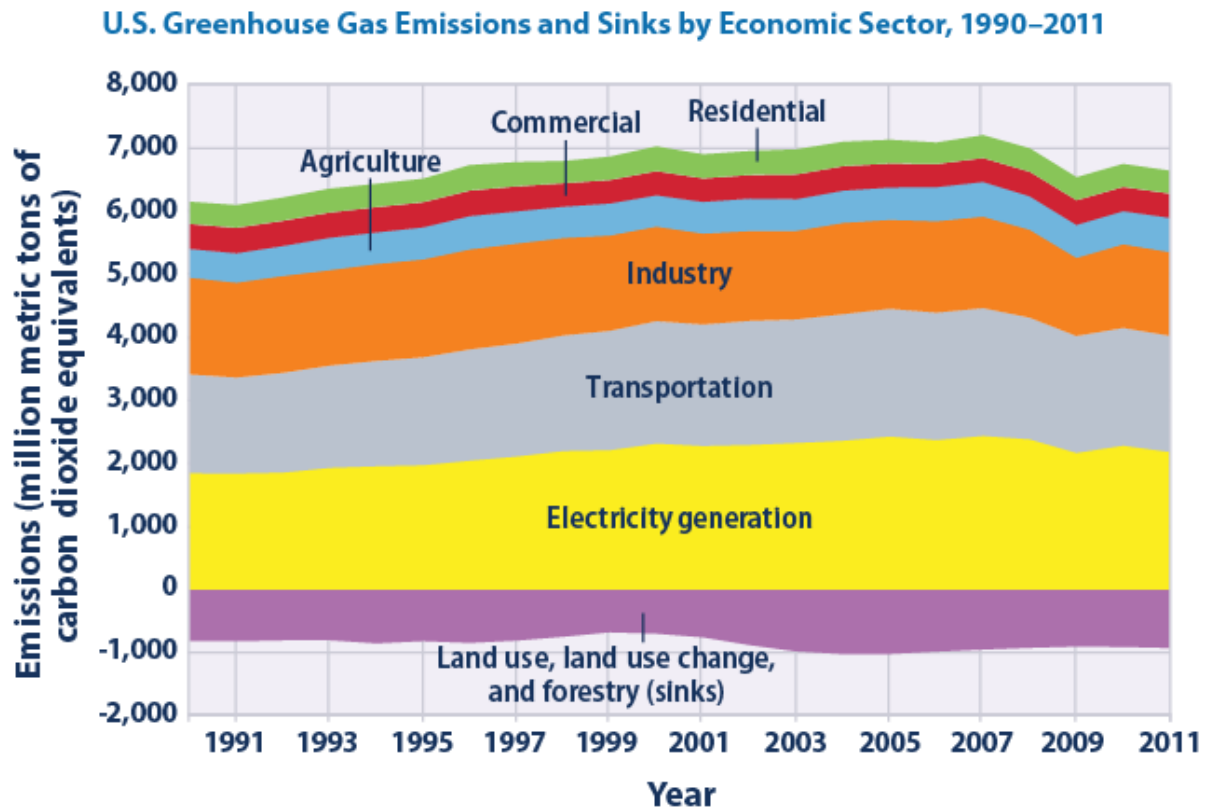


Figure 4 - U.S. Greenhouse Gas Emissions and Sinks by Economic Sector, 1991-2011 [4]

For the U.S. as a whole, electricity generation has composed roughly one-third of all greenhouse gas emissions. If the resource mix for the electric grid is not altered significantly and if technologies are not improved in the future, the scaling up of the primary energy consumption to meet the growing electric energy demand will indicate a scaling up of related greenhouse gas and criteria pollutant emissions, exacerbating the impacts on climate change and human health. This is important especially in developing countries.

1.1.1.2. Growing Demand for Transportation Services (Vehicle-Miles-Traveled)

After electricity generation, the transportation sector composes the next largest contributor from a single resource sector to greenhouse gas emissions as presented in Figure 4. The majority of the transportation-sector related greenhouse gases is sourced from light duty vehicles, which

comprised about 61% of the total transportation sector greenhouse gas emissions in the U.S. in 2012 [5]. Vehicle ownership for transportation services is currently viewed as one of the aspects of an increased quality of life, particularly in developing countries. In developed countries such as the U.S., however, the number of vehicle miles traveled per licensed driver is only expected to increase slightly. A projection for the vehicle-miles-traveled per licensed driver in the U.S. from 2011 to 2040, along with historical data from 1970 is presented in Figure 5 [6]:

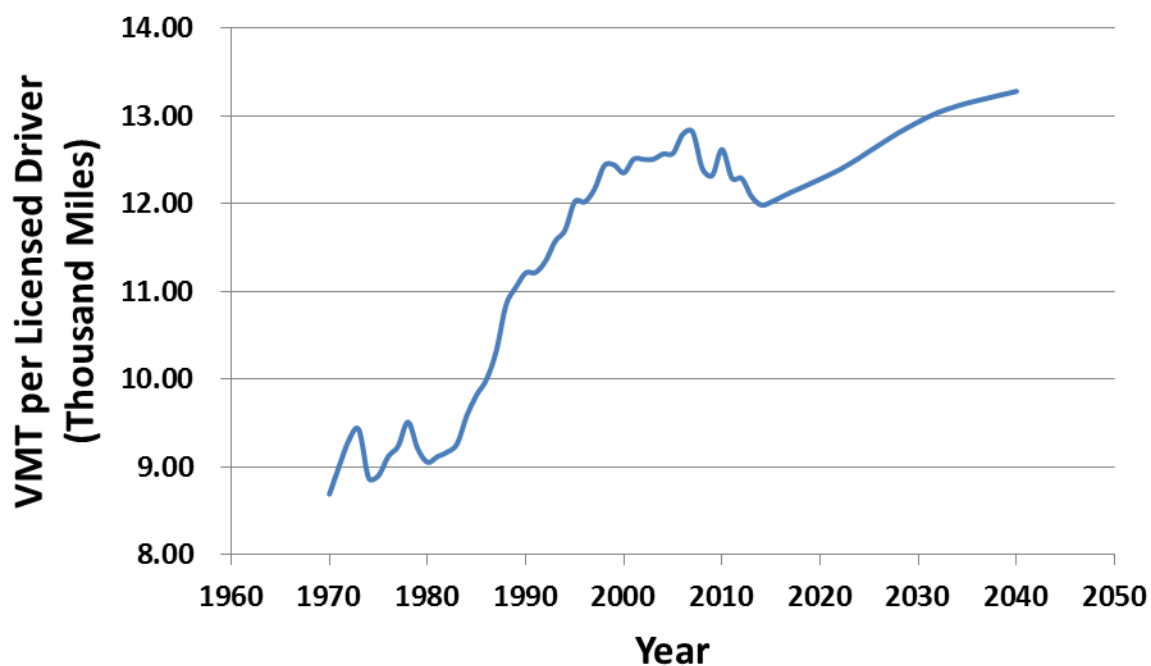


Figure 5 - VMT Demand per Licensed Driver Projections to 2040 for the U.S. [6]

Population increases may increase the vehicle-miles-traveled demand primarily by increasing the number of licensed drivers, however, population growth in developed countries is occurring at a lower rate compared to developing countries.

In developing countries, significant increases in vehicle-miles-traveled demand may occur due to large increases in population combined with increasingly larger shares of this population aiming

to own light-duty vehicles. A projection of the light-duty vehicle ownership for the world with a breakdown for different areas is presented in Figure 6 [7]:

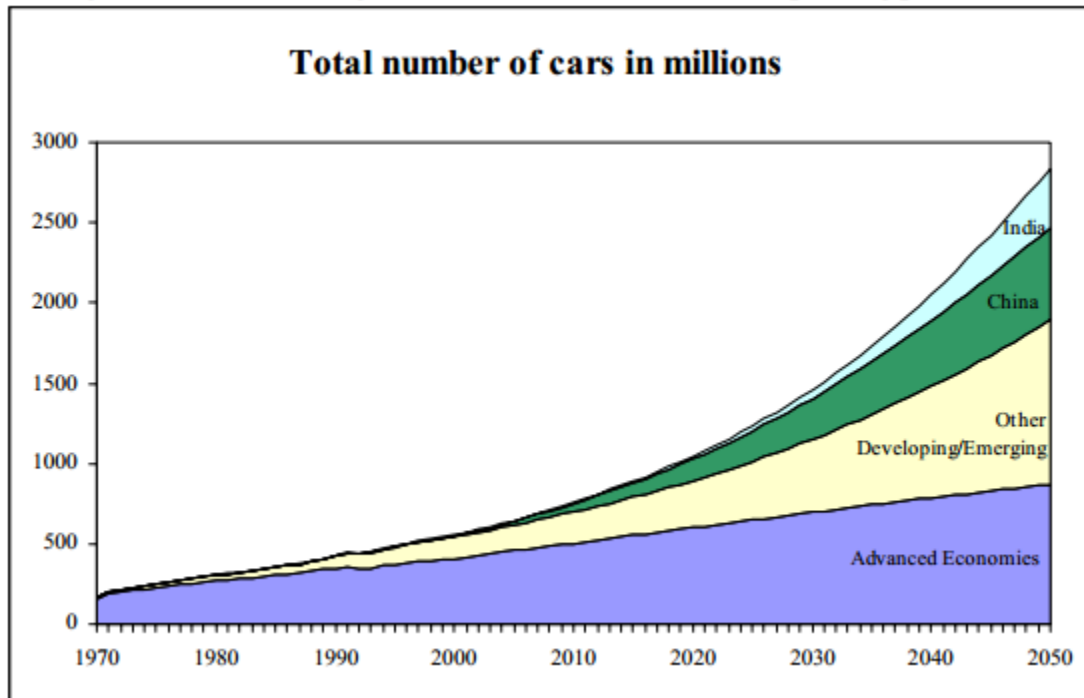


Figure 6 - Projection of World Car Ownership for Different Regions [7]

In previous years, advanced economies have comprised the dominant share of car ownership and therefore have been the largest contributors to the vehicle-miles-traveled demand. By 2050, however, worldwide car ownership is projected to increase by a factor of 3, with developing countries comprising roughly two-thirds of the fleet. The translation from car ownership to vehicle-miles-traveled varies from region to region depending on urban density, population distribution, and vehicle usage patterns. Significant increases in the amount of vehicles on the road worldwide, however, are correlated with increases in the vehicle-miles-traveled demand. This implies an increase in the resources used to provide those transportation services.

The light-duty transportation sector has relied heavily on petroleum as the primary fuel for providing transportation services. The primary energy consumption and greenhouse gas emissions of the transportation sector is similar in scale to the electricity sector, however, the former is responsible for the dominant share of criteria pollutant emissions. Similar to conventional power plants, the light-duty vehicle fleet therefore emits criteria air pollutants due to the combustion of fossil fuels. Power plants, however, are large scale systems which have the capability to install large-scale pollutant cleanup systems which significantly reduce criteria pollutant emissions from these facilities. Additionally, the generally higher efficiency and available fuel diversity of stationary power plants compared to on-road vehicles give the electricity sector more options for reducing criteria pollutant emissions. A comparison of the emissions of carbon monoxide and nitrous oxides, which are important regulated criteria pollutants for different sectors are presented in Figure 7 and Figure 8 [5], respectively:

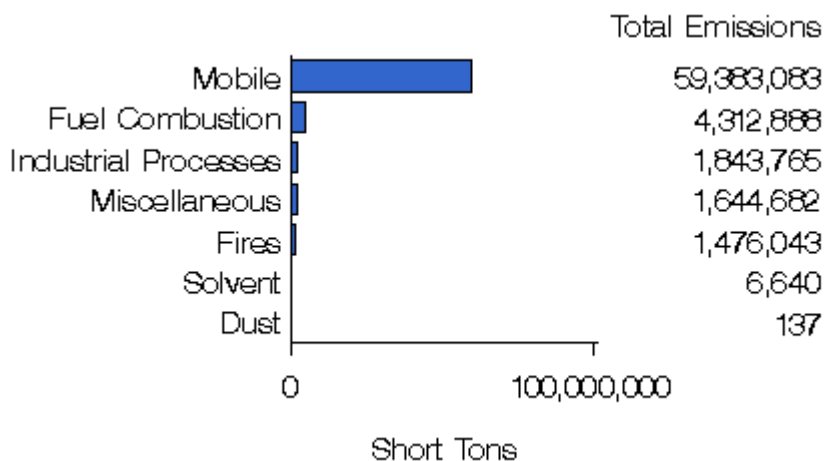


Figure 7 - National Carbon Monoxide Emissions by Source Sector in the U.S. in 2008 [5]

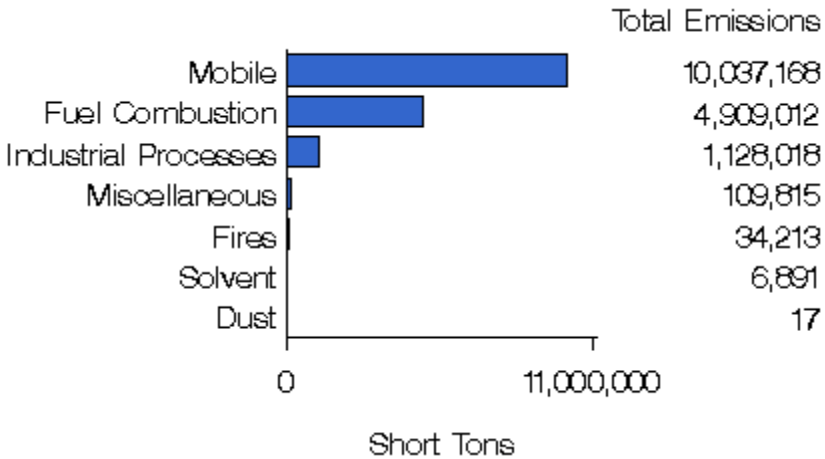


Figure 8 - National Nitrous Oxides Emissions by Source Sector in the U.S. in 2008 [5]

Mobile source criteria pollutant emissions significantly outweigh that from fuel combustion in power plants, and approximately two-thirds of the mobile emissions are due to on-road vehicles. Therefore, a scaling up of the vehicle-miles-traveled demand without significant changes or improvements in fuel use or vehicle performance implies a scaling up on these emissions levels, which will be detrimental for air quality.

1.1.1.3. Growing Demand for Water Resources

Adequate water supplies are also a necessary component of improved quality of life due to its use for human consumption, industrial processes, and hygiene. The projected increases in population will give rise to increases in the demand for water resources. Combined with decreasing supplies from historical water reservoirs in many regions and the potential effects of climate change, the ability to ensure sustainable access of water to citizens is a major challenge.

The focus on demand-side management of water resources, however, has historically been effective at partially or completely offsetting these increases. The freshwater withdrawal required to meet societal needs in the future will depend strongly on the extent to which these efficiency improvements are realized. For example, projections for changes in water demand

between 2005 and 2050 in California are presented in Figure 9 [8] for three different scenarios. The “Current Trends” scenario refers to the continuation of ongoing population growth and business-as-usual water usage trends. The “Slow & Strategic Growth” scenario refers to an optimistic case with lower-than-expected population growth, rapid adoption of water efficient technologies, planning of land use and adjustment of social behavior. The “Expansive Growth” scenario refers to a case with higher-than-average population growth and increasing urban land use. Water efficiency measures are still adopted but at a slower rate.

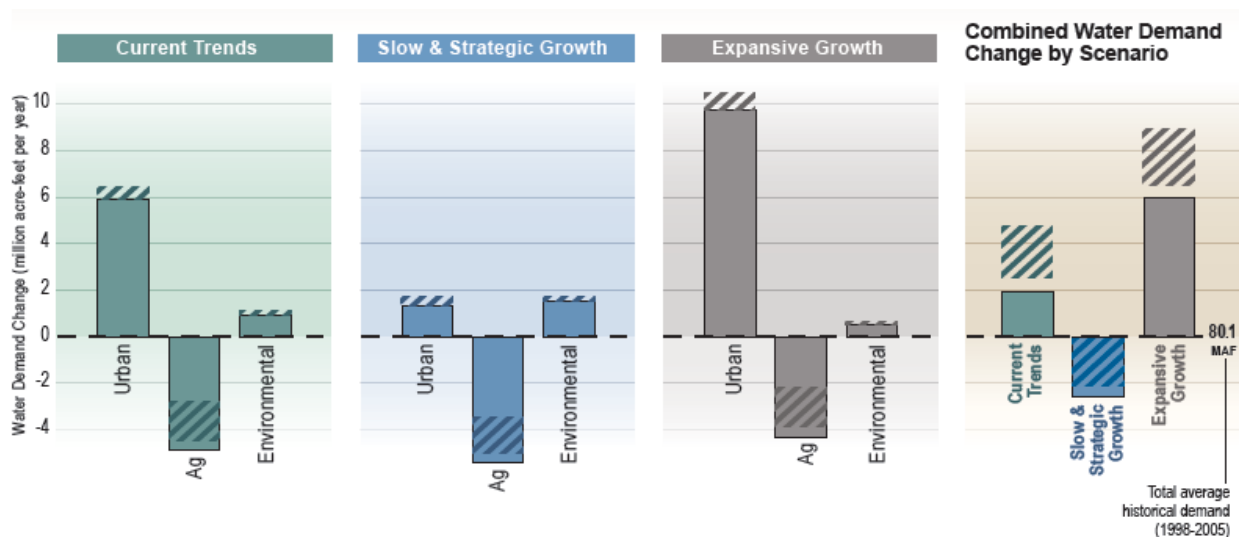


Figure 9 - Projections for the Change in Water Demand between 1998-2005 average levels and 2043-2050 average levels [8]

Future projections of changes in the water demand range from about -2.5 to +6 million acre-feet depending on realization of water usage efficiency improvements, the extent of population growth, patterns in land use and social behavior [8, 9]. This equates to about -3.12 to +7.5 percent of the average historical water demand between 1998 and 2005. Based on current trends, however, the total water demand is expected to grow by 2 million acre-feet per year, or about 2.5 percent of the average historical water demand between 1998 and 2005. The effects of climate

change can exacerbate water demand increases by increasing evaporation in agricultural settings. The water demand is expected to increase, but be partially limited due to the ability of water use management to respond to increased population.

Whether the water demand in different regions will match available supply from year to year or over long periods of time is a more complicated issue. Unlike the primary energy supplies for the transportation and electricity sectors, we do not actively control the supply of water, which is primarily sourced from precipitation. The rate of water extraction from surface and groundwater reservoirs to meet the water demand is causing a net decrease in the storage levels of these reservoirs in many regions. For example, projections for water demand and supply for Texas not yet counting the effects of climate change and the Colorado River basin with some uncertainty for climate change are presented in Figure 10 and Figure 11, respectively.

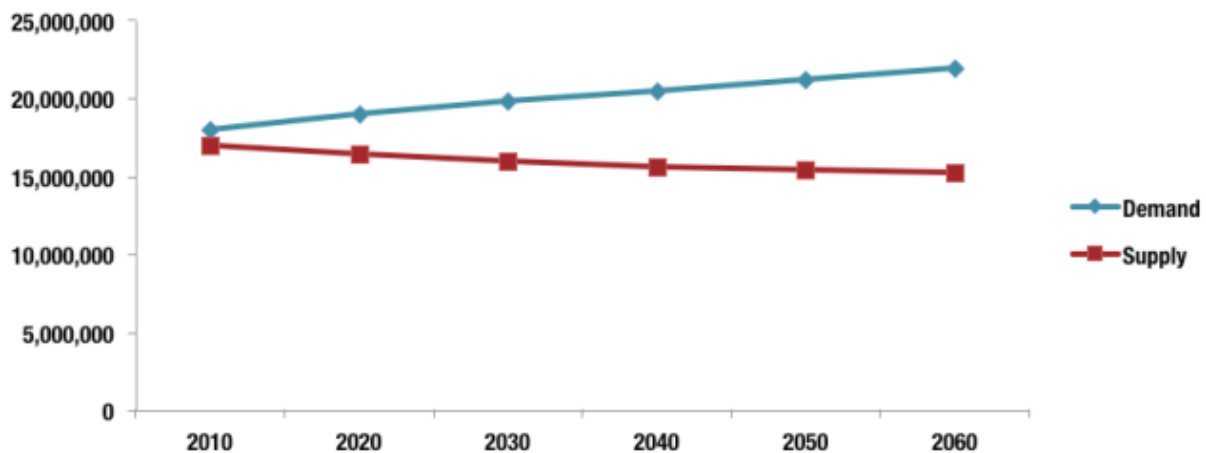


Figure 10 - Water Supply and Demand Projections in Texas up to 2060, in AF/year [10]

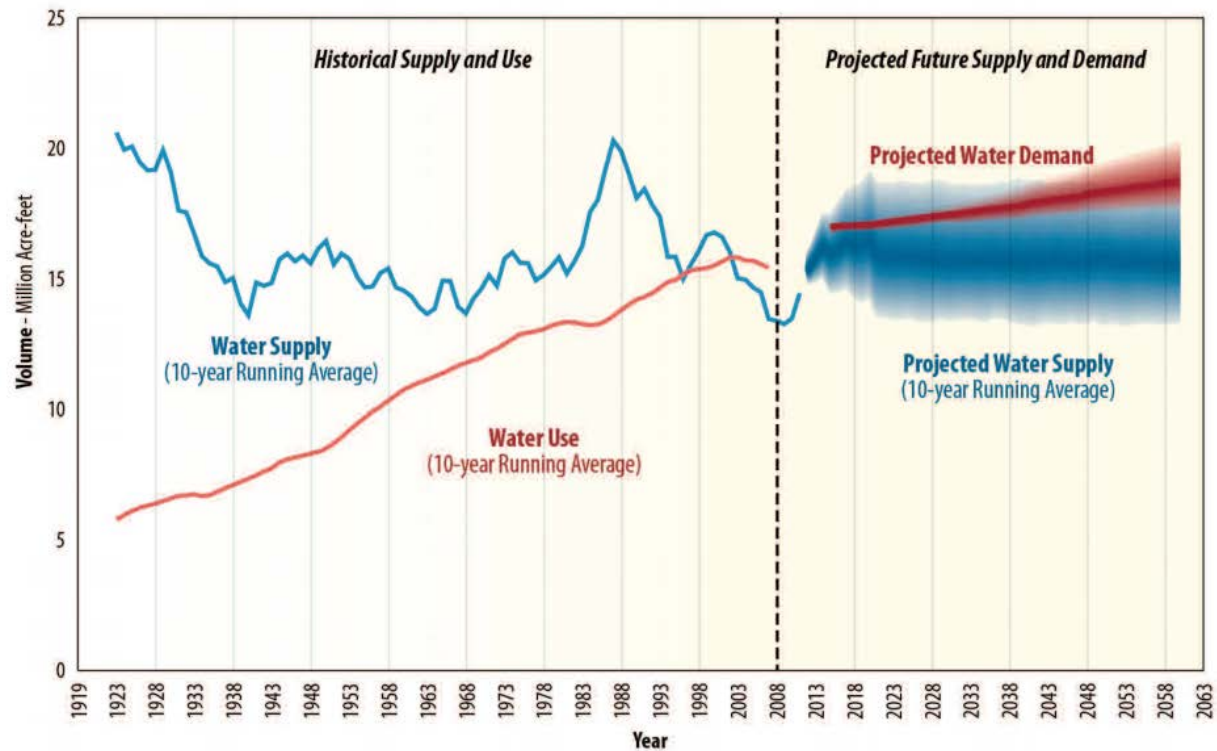


Figure 11 - Water Supply and Demand Projections in the Colorado River Basin up to 2060, in AF/year [11]

In future years, water demand is expected to exceed supply. While this gap will be buffered by use of stored water in surface and groundwater reservoirs, these stores will deplete eventually if extraction from these reservoirs continues to exceed the rate at which they are replenished. Therefore, it is not only the increase in water demand that poses a challenge, but rather the presence of an increasing demand with a decreasing supply. Without the implementation of novel water management options, demand augmentation, and potentially new supply from sources such as desalination, the provision of water resources to the world's growing population will be difficult.

1.1.2. Climate Change

In addition to the scaling up of demands for key resources and the detrimental effects that these trends have for environmental quality and resource availability, projected changes in the world's

climate due to greenhouse gas emissions have the potential to compound on the obstacle of increasing resource demands in maintaining the sustainability of societal operations into the future. A brief description of projected changes in climate and their implications for key resource security as well as quality of life is presented here.

1.1.2.1. Description of Climate Change Impacts

Climate change refers to the complex shifts in the major processes that govern Earth's climate patterns. These shifts have major implications for the design and operation of major resource sectors which meet societal needs. The specific manifestation of these shifts will vary widely by region, dependent on a variety of driving factors including but not limited to: spatial position relative to major weather systems and input solar energy intensity, regional land use, local geography/topography, and population. While the specific effects are regionally dependent, the causes of these shifts are global in nature, stemming from the effects of anthropogenic emission of greenhouse gases on the sensitive balance of the greenhouse effect in Earth's atmosphere. Before the potential effects of these shifts are described, some of the global shifts that give rise to these effects are briefly described here.

1.1.2.1.1. Global Mean Surface Temperature

The primary effect of anthropogenic contributions to the greenhouse effect is through an influence of the global mean surface temperature due to radiative forcing. The global mean surface temperature is the average temperature at the planet's surface, and is representative of the energy content contained in the atmosphere near the surface. It is important to note that while the global mean surface temperature will increase, the change in temperature in different regions will vary significantly. Certain regions will become significantly warmer while others may become

significantly cooler. The global mean surface temperature change from year 2005 levels for four different representative concentration pathway scenarios is presented in Figure 12 [12]:

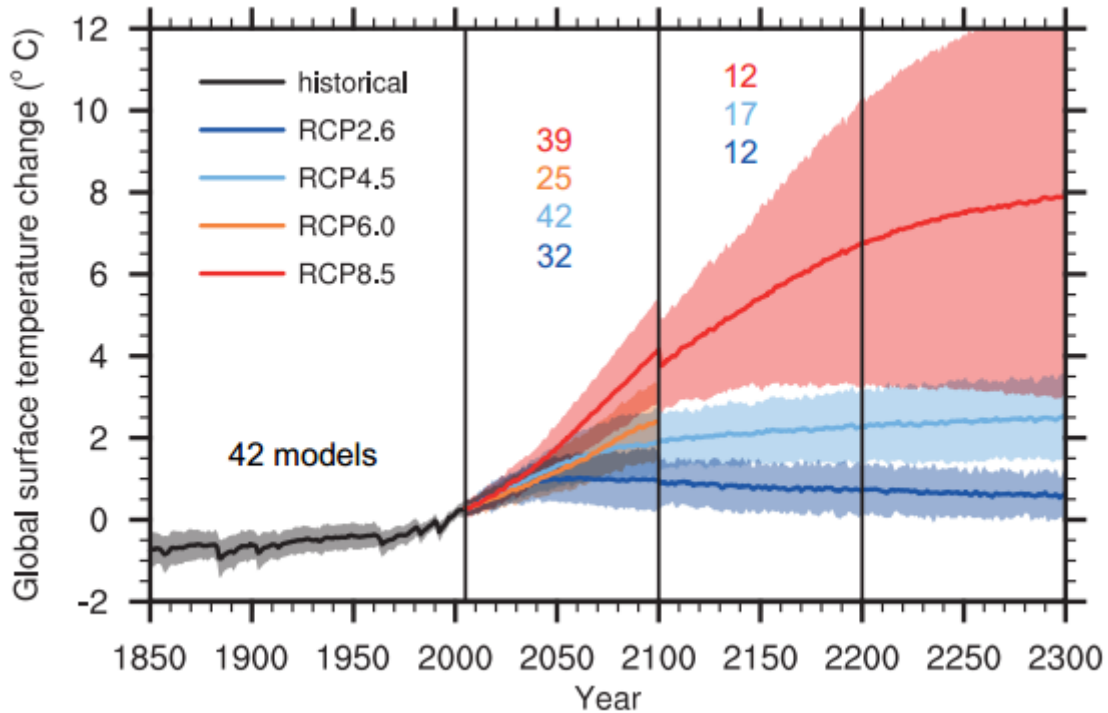


Figure 12 - Projected Global Mean Surface Temperature Change relative to 2005 levels for 4 Different Representative Concentration Pathway Scenarios [12]

Depending on the concentration pathway of greenhouse gases in the atmosphere, the global mean surface temperature can rise between 0.4 to 4.8°C by the year 2100. The scenario for the lowest concentration pathways displays a rise and subsequent decrease in temperature, while the others show continued increases. The regional distribution of this temperature anomaly is presented for the four different scenarios and two different time periods in Figure 13 [12]:

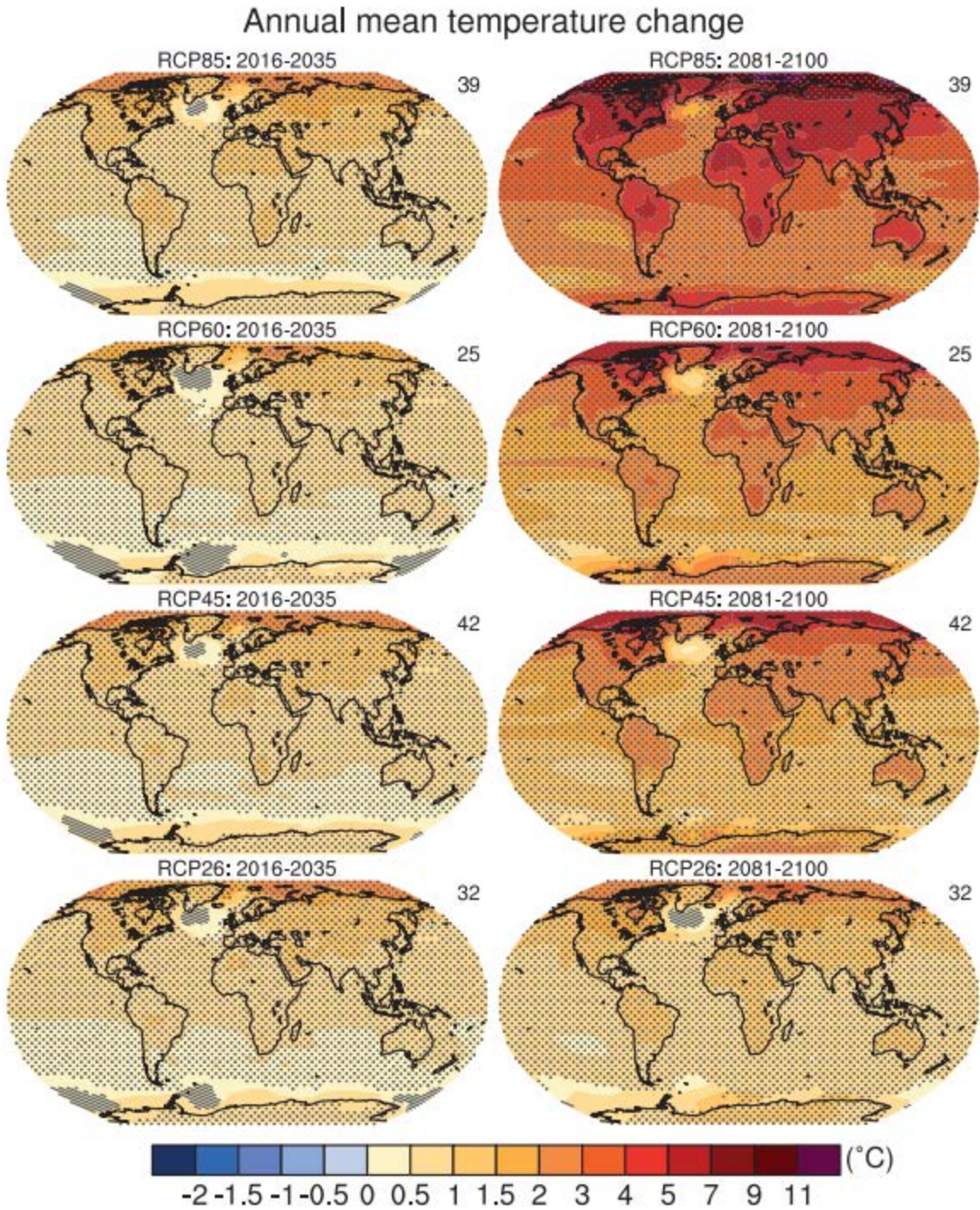


Figure 13 - Regional Distribution of Global Mean Surface Temperature Anomaly for 4 Different Representative Concentration Pathway Scenarios [12]

In general, warming is expected to be strongest at the poles, where the Arctic and Antarctic ice sheets are located. Increased air temperatures have strong implications for water demand, water supply, and electric grid operation. These implications will be discussed in a following section.

1.1.2.1.2. Sea Level Rise

Warming air temperatures will contribute to sea level rise through melting of Arctic and Antarctic ice sheets and through thermal expansion of the oceans. This has strong implications for coastal communities which are sited at or below the current sea level and/or must employ levees to protect water supplies from seawater intrusion and citizens from storm surges. The projections for the global mean sea level rise for the four different representative concentration pathway scenarios is presented in Figure 14 [12]:

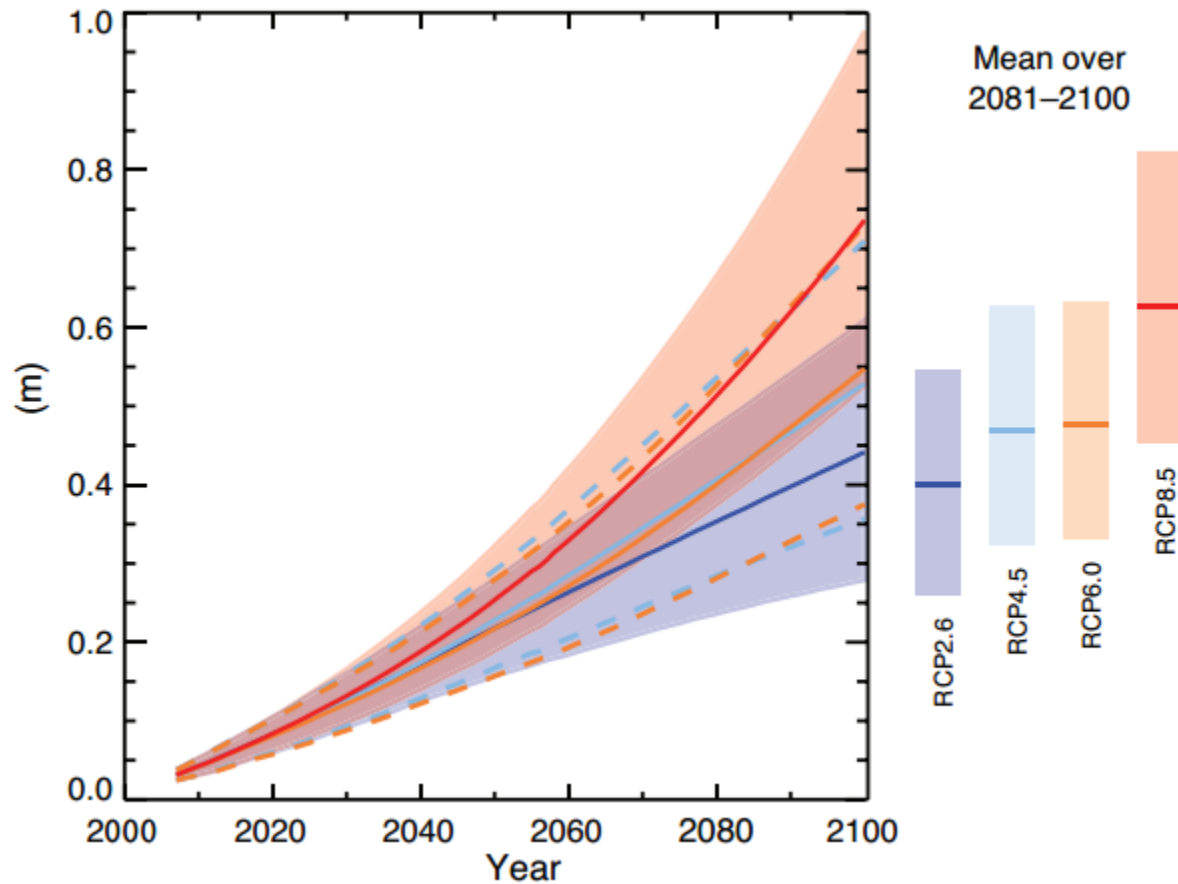


Figure 14 - Global Mean Sea Level Rise Projections up to 2100 [12]

Depending on scenario, the sea level is expected to rise by between 0.26 to 0.98 meters by the year 2100. Communities which are sited at sea level may need to take measures to prevent inundation under normal and under storm conditions, and protect their freshwater supplies from seawater intrusion into groundwater aquifers.

1.1.2.1.3. Precipitation Extremes

Increasing the energy content in the atmosphere will also have implications for the intensity of the water cycle, since the exchange of water through evaporation and precipitation are major mechanisms of energy exchange in the planet's energy cycle. The processes which give rise to these trends are beyond the scope of this dissertation, but the general conclusion is that climate

change will increase the severity and frequency of storm events as well as droughts. The evolution of the precipitation magnitude over time for four different representative concentration pathways is presented in Figure 15 . The top plot displays the 5-day accumulated precipitation from the wettest 5 days of the year as a global average, and the bottom plot displays the change in the average precipitation of very wet days, all as a change from 1998-2005 levels.

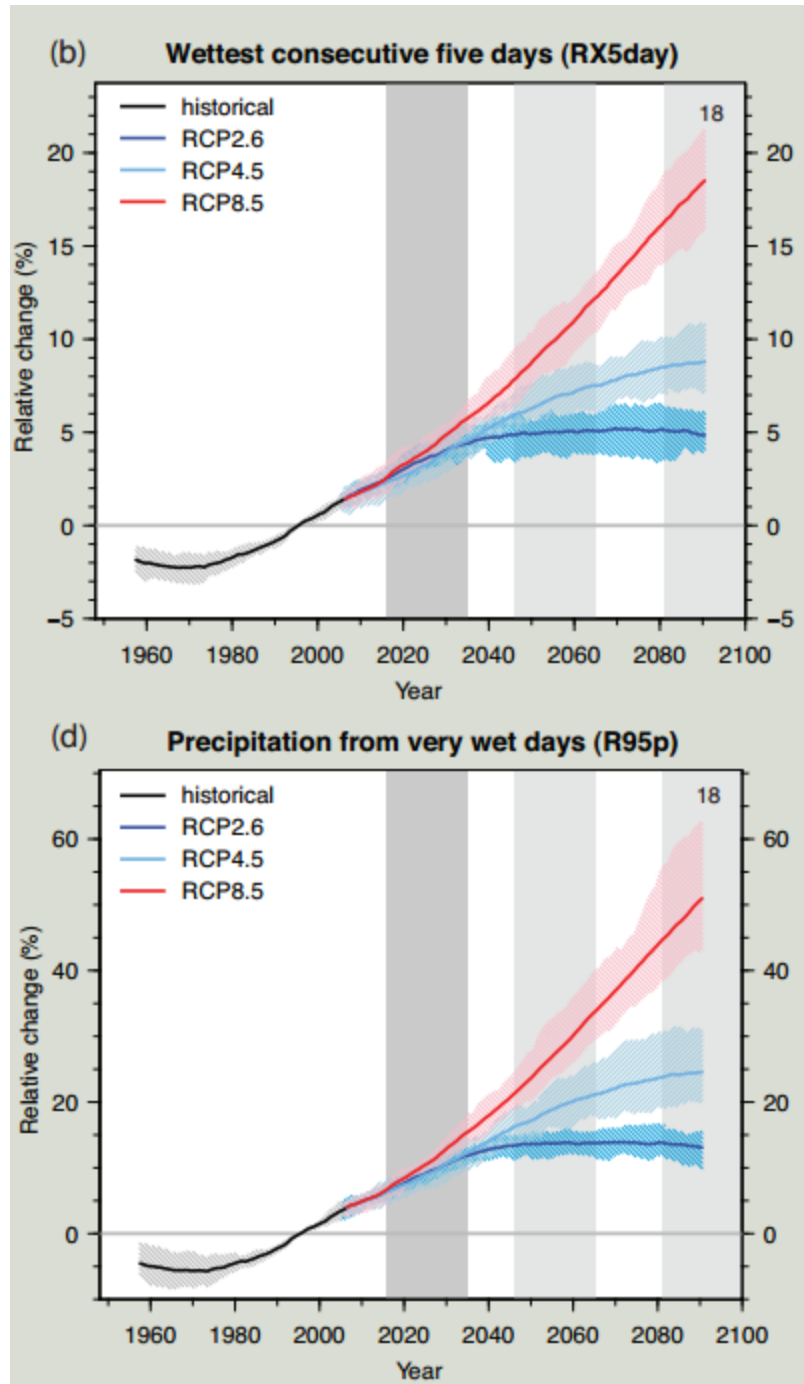


Figure 15 - Projections for Precipitation Event Magnitude Change from 1998-2005 levels for the 5 consecutive wettest days and for that from very wet days [12].

Increases in the intensity of storm events have strong implications for areas which rely heavily on hydropower for electricity and for flood management. In many regions, shifts in the frequency

and occurrence patterns of storm events can affect operations of the electricity sector and the availability of water supplies, requiring a change in water management practices.

1.1.2.2. Implications of Climate Change for Water Supply and Demand

The freshwater supply is inherently variable and dependent on weather conditions in any region and its surrounding areas. Additionally, the extent of water demand in certain end uses is also highly dependent on ambient weather conditions. This section seeks to provide an overview of the implications for climate change impacts on the mechanics of the water sector. Since California is the primary focus of this dissertation and water impacts are specific by region, much of the literature discussed here is relevant to this area.

1.1.2.2.1. Climate Change and Freshwater Supply

The vast majority of precipitation in California comes in the form of rain or snowfall in the northern and eastern regions. Snowfall is particularly important because it allows freshwater to be stored and be gradually released over time as runoff. This allows natural reservoirs such as streams and rivers to maintain relatively steady levels and reduces flood risks. Release of freshwater from melting snowpack tends to occur in the late-spring and early summer months when the water demand is increasing. Historical planning and operation of the water supply infrastructure has been based upon using man-made reservoirs to capture some of this freshwater and provide it during the dry late-summer and early-fall months. The melting of snowpack alone has historically contributed about 15 million acre-feet of freshwater per year on average [8], released between April and July.

One of the major effects of climate change in California is rising air temperatures. Warmer air temperatures will cause precipitation to fall in the form of rain rather than snow in the northeastern mountain regions, decreasing the size of the snowpack. By 2050, the Department of

Water Resources (DWR) projects that the amount of water stored in the Sierra snowpack will decrease by between 25 to 40 percent [8]. Total snowpack is expected to decrease by between 60 to 80 percent by 2070. Projections of snowpack storage in the Upper River Basin of California as a function of temperature increase are presented in Figure 16:

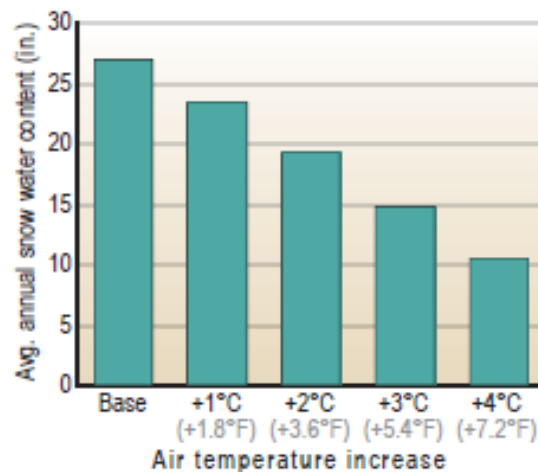


Figure 16- Average Annual Snow Water Content in the Upper River Basin vs. Air Temperature Increase [8]

A shift from snow to rain indicates that freshwater from precipitation will be released into the rivers and streams immediately as opposed to the gradual release due to snowmelt. This can cause flooding concerns since river and stream levels will rise in response to receiving the full amount of freshwater supply from precipitation during the rainy winter seasons. Current man-made reservoirs which augment river and stream levels by withholding and releasing freshwater stored from rivers are designed to hold a given capacity of water. With increased river and stream flow, reservoirs may reach capacity quickly and be forced to release water downstream and cause flooding and waste freshwater during rainy seasons.

Decreased snowpack changes the timing of freshwater supply. The gradual release of freshwater from snowpack required the water infrastructure to store smaller amounts of water in the

springtime and allow it to be available to meet high demand during the hotter and drier months in the summer and early fall. Without snowpack storage and gradual release, freshwater will be highly available during the rainy season when demand is low, likely resulting in a waste of freshwater supply by allowing it to flow to the ocean or other sinks before usage. Consequently, during the dry seasons when the water demand is at its highest, reservoirs will be stressed and the amount of freshwater available for use will be limited. An example of this is displayed by the projected average annual runoff in the Upper American River Project as a function of month of the year as presented in Figure 17 [13]:

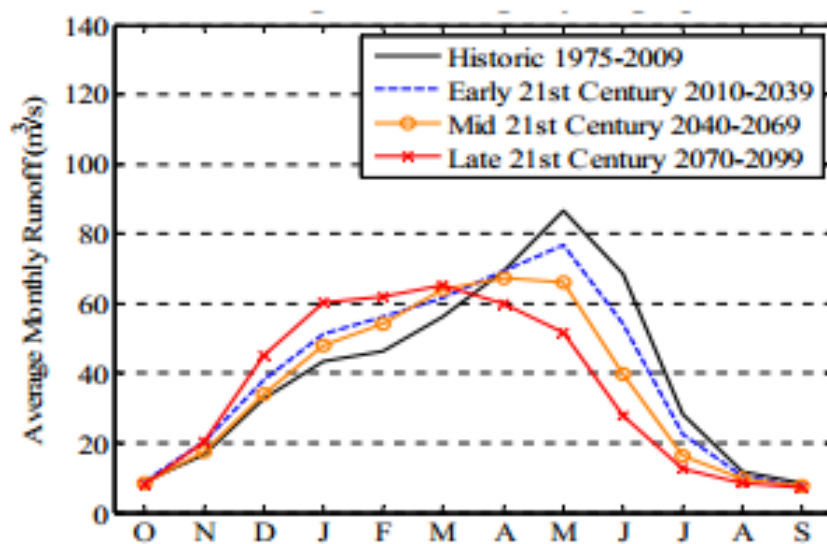


Figure 17 - Seasonal Profile of Water Runoff in the Upper American River Project subject to Climate Change [13]

These effects are also expected to be exacerbated due to the increased severity of storm events anticipated due to climate change. Severe storms will cause larger amounts of water to enter rivers and streams in shorter periods of time. Additionally, to compensate for this decrease in available freshwater supply during the dry months, increased reliance on groundwater aquifers may become necessary, leading to aquifer depletion.

Sea level rise is also a concern, contributing to increased water volume, and land movement. For the California coast in particular, the sea level is expected to rise between 4 and 16 inches at the Golden Gate area by 2050. Rising sea levels have the potential to increase saltwater intrusion into freshwater supplies and natural reservoirs such as the Sacramento Delta and coastal aquifers. At current, additional water is released from man-made reservoirs to repel saltwater intrusion into key freshwater supplies. Due to the effects of climate change, however, man-made reservoirs may not have enough stored freshwater to carry out this task or increase its intensity to combat increased saltwater intrusion due to sea level rise.

Rising sea levels can also potentially disrupt freshwater supplies through flooding of key freshwater reservoirs such as the Sacramento Delta. Higher sea levels decrease the ability of levees that protect the Delta to prevent flooding. With more intense storms and a lower flood margin, these levees can potentially fail and allow significant inundation of the Delta by salt water. This would contaminate freshwater supplies, degrade water quality, and severely disrupt the availability of freshwater to the state since many areas rely on water imports from the Delta. Additionally, sea level rise can also cause flooding of many wastewater treatment plants located on the coast.

Overall, the effects of climate change can potentially have significant effects on the freshwater supply. Many of these effects compound with each other, and collectively have the potential to reduce the ability of the current water infrastructure to meet growing water demands. To meet these challenges while maintaining freshwater availability to end-users, the design and operation of the water supply infrastructure will need to be adjusted.

1.1.2.2.2. Climate Change and the Water Demand

The effects of climate change also have implications for the water demand as well as the water supply. In Section 1.1.1.3, a projection of the water demand for California was presented for different growth scenarios between 2005 and 2050. Without considering the effects of climate change, the change in the average water demand was projected to be between -2.5 to +6 million acre-feet or -3.12 to +7.5 percent of the average annual demand between the years of 1998 and 2005 depending on growth scenario. Continuation of current growth trends resulted in a 2.5 percent increase. The effects of climate change alter these ranges considerably. For the least severe climate change scenarios displayed previously, the change in statewide water demand is projected to be between -2.25 to 6.5 million acre-feet, corresponding to changes of -2.8 to +8.1 percent of the average annual demand between 1998 and 2005. Continuation of current growth trends results in a projected increase in demand of 3.1 percent. For the most severe climate change scenarios, this is range is altered to between no change at the lower end and +9 million acre-feet at the upper end. This corresponds to changes of 0 percent and +11.2 percent of the average annual demand between the years of 1998 and 2005. Current growth trends in this case result in a projected demand increase of 6.2 percent [8].

These changes are distributed differently between the urban and agriculture sectors. Climate change has the most significant effect on the agricultural water demand, and generally acts to counter many of the efficiency advancements in water use that are projected to be implemented. Higher average temperatures primarily contribute to increased evaporation rates for water in the soil of irrigated farmland. This requires more water for farmland irrigation to allow crops to absorb the amount of water required for adequate growth. The high surface area of farmlands allows a small increase in evaporation rates to result in a large increase in water demand.

The effect of climate change on the urban water demand is less significant than that on the agricultural water demand. Higher temperatures also contribute to increased evaporation rates, especially in water used for exterior landscaping. However, the majority of urban water end-uses are not affected significantly by increased ambient temperatures from the perspective of water demand. The effect of climate change was deemed to be weaker than the effect of raw population growth on the urban water demand.

In any of the growth cases presented in the DWR Water Plan Update, the cases that consider climate change exhibit increased water demands compared to the cases based on historical hydrology. By itself, the increase in water demand may not pose a significant problem that the water supply infrastructure would not be able to solve. Combined with the effects of climate change on the water supply, however, the increased water demand only serves to add to the difficulty of procuring enough freshwater resources to meet the water demand in the future.

1.1.2.3. Implications of Climate Change for Electricity Supply and Demand

The effects of climate change also have implications for the operation of the electric power system. Many of these effects are closely coupled with the concurrent implications for water supply and demand, as will be discussed in the next section. Since California will be the major focus of this dissertation, much of the literature discussed here is relevant to the state, however, more general effects are also discussed.

1.1.2.3.1. Climate Change and Hydropower

The water supply from precipitation is variable from year to year and this causes the capacity factor and role of hydropower generation to change to a certain extent from year to year. The effects of climate change on the water supply as discussed in the previous section, however, can

not only exacerbate this variability but alter the ability of hydropower to provide critical services to the electric power system.

The storage of water in the form of snowpack leads to a gradual release of freshwater, and the current reservoirs store water during the spring and winter and release it in the summer and fall. The production capability of hydropower parallels the timing of this release. The gradual release of freshwater allows the ability of hydropower to provide load-following, spinning reserve, and regulation services to remain steady throughout the year. This occurs because a steady release of water from the snowpack allows man-made reservoir levels at hydropower plants to remain relatively steady, and power plant operators have more flexibility regarding when and how much power these plants generate.

With the effects of climate change, however, river and stream levels will be more closely tied to temporal precipitation patterns. During seasons of heavy precipitation, more water will be available for the reservoirs of hydropower plants and these units will be capable of producing power at rated capacity and exhibiting increased load-following capability. The opposite occurs for dry seasons, where the reservoirs at hydropower plants will be stressed due to low river and stream levels and a lack of ability to store the water provided by the more severe storm events. In this case, hydropower plants will have limited ability for load-following and will likely only be able to produce power at smaller fractions of their rated capacities [14].

This change in hydropower production capability does not complement the seasonal behavior of the electric load demand. The electric load demand peaks during the summer and early fall months, when temperatures tend to be the highest and precipitation is in short supply. These months are when the services that can be provided by hydropower are most essential, because

these units provide load-following and spinning reserve capacity without producing greenhouse gases or criteria pollutants. With the effects of climate change, however, these months will be when hydropower has a limited ability to provide those services. Conversely, the electric load demand tends to be lowest in California during the winter and early spring months when temperatures are low and precipitation is high. With the effects of climate change, these months will be when hydropower plants have the most flexibility for providing load-following and spinning reserve services. Since the electric load demand is relatively low at this time, this is when hydropower services are not as essential.

These effects can also decrease the total energy contribution of hydropower towards serving the electric load demand. The limited capacity of reservoirs at hydropower plants may cause these units to be required to spill water during wet months. Spilling refers to the practice of releasing water from the upper reservoir at a hydropower plant without routing it through the turbines. This water is allowed to flow downstream without producing any electric power. Spilling is either voluntary or involuntary. In voluntary spilling, water is released to meet demand for water downstream in excess of that provided by running the hydropower plant at full capacity. Examples include additional water flow to aid fish migration or meet urban or agricultural needs on a given day [15]. In involuntary spilling, water is released to prevent the hydraulic capacity of the reservoir from being exceeded. When the inlet river or stream introduces a large flow of water to the reservoir that may cause it to exceed capacity, the hydropower plant will run at full capacity to prevent excess buildup of water in the reservoir. If the water outflow due to running the plant at full capacity is insufficient, extra water is released through involuntary spill [15].

The increase in peak river and stream flows during the winter months due to decreased snowpack storage has the potential to increase involuntary spill amounts. This decreases the annual amount of electric energy obtained from hydropower plants. For example, generation by hydropower plants in the Central Valley Project is expected to decrease by about 3 percent by the mid-century and 6 percent by the end of the current century. Similarly, generation by hydropower plants in the State Water Project is expected to decrease by about 6 percent by the mid-century and 10 percent by the end of the current century [16].

The decrease in the energy and flexibility contribution of hydropower has many undesirable implications in the context of the evolution of the electric power system to support renewable power. Hydropower provides significant energy contributions that displace fuel use in thermal power plants and prevent the emission of greenhouse gas and criteria pollutants that would otherwise exist. This resource also provides significant flexibility to the balancing power plant fleet, a characteristic that will become much more valuable to the system at increased variable renewable penetration levels on the electric grid.

Combined with an increasing electric load demand due to population growth and the electrification of the transportation sector, the decreased role of hydropower will require significantly improved capabilities in thermal power plants to balance the system and support increased variable renewable power capacities. Thermal power plants – particularly gas-turbine thermal power plants – will be required to substitute for hydropower in key roles in the electric power system. This will contribute to increased greenhouse gas and criteria pollutant emissions, as well as fuel use. The alternative would be to use complementary technologies to provide

certain services such as spinning reserve directly, or use these technologies to enable renewable power plants to provide these services.

1.1.2.3.2. Climate Change and Thermal Power Plants

For thermal power plants, a lower minimum temperature in a thermal power plant cycle contributes to higher efficiencies for a fixed maximum temperature. Minimum cycle temperatures for steam-turbine thermal plants are determined by the cooling method used by the power plant, with dry-cooling methods causing the minimum cycle temperature to be slightly higher than the ambient air temperature and follow its behavior throughout the day. The minimum cycle temperature for gas-turbine thermal plants is exactly the ambient air temperature since working fluid is taken from the atmosphere.

Gas-turbine power plants provide the vast majority of thermal power plant capacity in California and a significant amount of the energy contribution towards serving the electric load demand. The efficiency of these power plants is already affected by daily variations in ambient temperature, with efficiencies decreasing during the daytime when temperatures are at their highest. Additionally, measures to reduce water withdrawal and consumption for thermal power plant cooling which implies a shift from wet-cooling methods towards dry-cooling for both renewable-fueled and fossil-fueled steam-turbine thermal power plants. This indicates that the efficiencies for the overall thermal power plant fleet will be more strongly tied with ambient air temperature.

The increased average ambient temperatures that can occur due to climate change have the potential to decrease the efficiency of the thermal power plant fleet. For conventional power plants fueled by natural gas, this implies increased fuel usage, greenhouse gas and criteria pollutant emissions. Solar thermal power plants will require larger concentrator areas to produce

a given power output, leading to larger land use requirements. Similarly, geothermal power plants will need to absorb larger amounts of thermal energy from hot rock resources to provide a given power output, potentially leading to increased resource depletion.

The exact extent of the efficiency decrease will depend on the design parameters of specific power plants. As an example, a typical geothermal power plant with a 330°F hot rock resource will decrease in power output by about 1 percent from rated capacity for every 1°F in ambient temperature rise [17].

1.1.2.3.3. Climate Change and the Electric Load Demand

As discussed previously, the electric load demand is expected to increase with population growth. The effect of increasing average temperatures due to climate change can serve to exacerbate this trend by increasing air-conditioning loads in residential and commercial buildings. Residential and commercial space cooling accounted for 30 percent of the total peak electric load demand in 2004 alone [16], and this demand is expected to increase in the future.

The increase in the electric load demand due to space cooling of the residential sector alone is dependent on greenhouse gas emissions scenarios for the world as a whole. In a business-as-usual type of scenario, the electric load demand in California is expected to be about 7 percent by 2040 in excess of that caused by population alone. By 2100, this figure rises to a 50 percent increase. In another scenario where sustainability practices and limitation of population growth peaks during the mid-century, the increase in load demand by 2100 is reduced to 20 percent in excess of that caused by population growth alone [16, 18].

The increase in the electric load demand due to increased cooling loads is not spatially uniform, however. Coastal areas were only found to have a modest increase in the frequency of high

temperature days and therefore cooling demand. Inland areas, however, were found to potentially have significant increases in cooling demand since temperature increases due to climate change are more significant in these areas. For the same business-as-usual climate scenario, coastal areas are only expected to exhibit a 2 percent demand increase by 2040, compared to a 29 percent increase for areas such as the Central Valley. By 2100, these figures change to 3 percent for coastal areas and 122 percent for the Central Valley [18].

Overall, the effects of climate change can potentially accelerate the increase in the electric load demand over time.

1.1.2.3.4. Climate Change and Wind Power

The behavior of wind power is also dependent on local weather patterns. The interaction of high pressure and low pressure weather systems with regional geography determines the magnitude and profile of wind speed in a given area. With the effects of climate change slated to affect average temperatures, these effects can also influence the behavior of wind power in California.

Temperature, however, is only one major parameter of the weather system. Changing temperatures due to climate change can therefore have different effects on wind speeds. At the current time, the exact manner in which climate change will affect wind power is not clear.

Rasmussen compared different climate models to analyze the effect of climate change on the spatial distribution of wind speed in major wind resource areas in California such as the Tehachapi, Altamont, and San Geronio mountain passes. It was discovered that the projection of changes in wind speed and spatial distribution were highly dependent on the climate model used, and no definitive statement regarding how wind speed will change with climate change could be made [19, 20].

For the United States as a whole, Breslow used climate models to predict the effect of climate change on wind speeds in the continental states using different general circulation models. It was discovered that the seasonal mean wind speed of the contiguous U.S. was expected to decrease by between 1.0 to 3.2 percent in the next 50 years, and between 1.4 to 4.5 percent in the next 100 years. However, there was a large disagreement between the different climate models, especially for scenarios after 2050 [21].

Overall, temperature is a major driving factor in weather systems. Since the spatial and temporal behavior of wind speeds is dependent on that of weather systems, climate change can influence wind power production. The extent to which this will take place is unclear, and determining such will require refinement of current climate models.

1.2. Sustainability Goals

In response to the convergence of the challenges presented in the previous section, our society has set sustainability goals, which are targets that if met, are believed to help societal operations progress towards being sustainable. A definition of sustainability in this context along with a description of sustainability goals on different societal scales are presented in brief as follows.

1.2.1. Definition of Sustainability

When addressing the challenge of increasing the sustainability of societal operations that enable an adequate quality of life, it is important to understand what it means for our society to be sustainable. In its most general, conceptual form, the operations of a society are sustainable if it is able to meet the needs of current citizens without compromising the ability of future citizens to meet their needs. This definition, however, is somewhat vague from the perspective of people who are actively attempting to develop plans and strategies to render our society as a sustainable one, especially from an engineering and science standpoint.

In order to make the goal of sustainability more tangible for a planning audience in the engineering and science fields, a definition of sustainability from the technical perspective can be presented as follows. The operations of a society are considered sustainable if it does the following:

1. **Creates and maintains a physical environment which enables citizens to enjoy an acceptable living standard.** For example, if the physical environment shifts in a way which has consequences for human health, such as degraded air or water quality, then it will be more difficult for citizens to meet a desired quality of life.
2. **Secures the supply of key primary resources which enable societal functions.** For example, water is a key resource that is needed for human nourishment and hygiene. Inability to provide sufficient water resources will make it more difficult for citizen to meet a desired quality of life.

There are many other dimensions to sustainability that must be considered, such as sustainability from the social and economic standpoints. Addressing these other dimensions directly is beyond the direct scope of this dissertation, however, these aspects are important and coupled with physical sustainability nonetheless. With a more tangible concept for what we are working towards, we as a society can set more specific goals for specific operations of our society to contribute towards meeting the presented definition. These more specific and tangible goals are discussed in this section.

1.2.2. Holistic Sustainability Goals

A resource sector refers to all of the operations and infrastructure that are used to provide a specific, key service or good to enable an adequate quality of life. For example, electricity is a

resource sector and involves every aspect required to provide electric service to society. Holistic sustainability goals refer to specific targets that the combined system of all resource sectors must meet to progress towards rendering our society as sustainable. Some of these goals are presented as follows:

- **Reducing Greenhouse Gas Emissions.** As presented previously, anthropogenic emissions of greenhouse gases are currently having an effect on climate patterns on a worldwide scale. Many of these effects can compound on challenges for our ability to secure key resources such as water, food, and energy due to increases in the demand for the latter. This is accomplished by reducing the greenhouse gas intensity of major resource sectors. Policy measures of broad scope have currently been developed in certain regions to accomplish this, such as Assembly Bill 32 (AB32) in California [22].
- **Improving Air Quality.** Acceptable air quality is important for human health, with nominally 200,000 premature deaths occurring annually due to the effects of criteria pollutants on the human respiratory system in the U.S. alone [23]. This is especially important in areas such as California, where high populations and unfavorable geography and climate in the southern regions render it difficult to meet federal air quality attainment standards.
- **Safeguarding Water Quality.** Acceptable water quality is important for human health in a similar matter as that for air quality, as well as for ecosystem health which society depends on to provide food supplies. Water resources which contain high amounts of toxic compounds or pathogens give rise to a number of diseases which can be debilitating or fatal, therefore societal needs must be met with this taken into account.

- **Securing the Primary Energy Supply.** Energy in different forms is a key enabler for essentially all resource sectors that enable an acceptable quality of life. Electric service, transportation, manufacturing, water supply, and the like all rely on primary energy input to function. An inability to secure the supply of primary energy resources, either due to depletion of finite resource reserves, energy security concerns, or excessive increases in demand would be detrimental to the function of all resource sectors.
- **Securing the Primary Water Supply.** Similar to the energy supply, sufficient water resources are critical for human nourishment as well as the operation of key processes in various resource sectors. An inability to secure the primary water supply would be detrimental to the operations of these resource sectors and to the quality of life that are enabled by them.
- **Adapting Resource Sector Operations to Climate Change.** Currently, society has already used up a certain portion of the carbon budget and a certain level of climate change effects are expected to occur. While there is the potential to limit the extent of these effects by reducing greenhouse gases, the infrastructures of different resource sectors must be able to operate robustly under the extent of these effects that may occur.

1.2.3. Individual Resource Sector Sustainability Goals

From a planning standpoint, the holistic sustainability goals may still be too vague to provide specific directions how the design and operation of major resource sectors should be changed to a more sustainable paradigm. Therefore, to render the goal of sustainability more tangible from a planning and policy perspective, more goals which are more specific and tangible to the design and operation of individual resource sectors have been set. These goals and progress towards

them are believed to represent the contributions of different resource sectors towards meeting the holistic sustainability goals.

1.2.3.1. Electricity Sector

The following represents some of the major sustainability-oriented goals which are specific to the electricity sector.

1.2.3.1.1. Increasing the Share of Renewable Resources in the Grid Mix

With the understanding of a finite availability of fossil-fuel resources and the effects of criteria pollutant and greenhouse gas emissions, the primary contribution of the electricity sector towards meeting sustainability goals will be sourced in a shift of the electric grid resource mix towards larger shares of low-carbon, renewable energy input sources. Increasing the renewable share of the electric grid mix contributes towards reducing the greenhouse gas and pollutant emissions intensity of the electric grid, as well as securing the primary energy supply.

A formal policy for reaching a given penetration of renewable resources into the overall grid mix is called a renewable portfolio standard. The renewable resource penetration level into the grid mix for each region and the timing for when they are to be achieved will vary by region due to a number of factors. Different areas have more or less access to a different set of renewable resource potential. For an example in the U.S., states such as California and Arizona have access to areas with high levels of solar radiation, allowing solar power to make a larger feasible contribution to the overall mix. By contrast, states in the New England region may have to rely on their offshore wind potential as the dominant renewable type.

A list of some of the most aggressive renewable portfolio standards which are in place as of March 2013 are presented in Table 2 [24]:

Table 2 - Renewable Portfolio Standards in the U.S. as of March 2013

<u>State</u>	<u>Target Renewable Penetration Level</u>	<u>Target Year of Attainment</u>
Hawaii	40%	2030
California	33%	2020
Colorado	30% for IOUs 10% for Municipal	2020
New York	29%	2015
Connecticut	27%	2020
Nevada	25%	2025
Oregon	25%	2025
Illinois	25%	2025

The details of what types of energy sources are counted as renewable and the types of credits or offsets that can be used in place of actual renewable installations vary significantly with region.

The challenges associated with actually reaching these targets are a popular topic of current research, and can also vary significantly by region.

1.2.3.1.2. Reducing Pollutant and Greenhouse Gas Emissions from Power Plants

Until the entire grid mix is able to be composed low/zero-carbon or criteria pollutant emission power plant types, conventional power plants which operate on different types of fossil fuels will still be a significant portion of the grid mix. Since many of these power plant types rely on the combustion of fossil fuels, these power plants emit various levels of criteria pollutants which affect local air quality. Therefore, standards have been set to regulate and reduce the emissions of compounds that have been identified as contributors to air quality degradation have been set in place.

In the U.S., national standards for limits on the emission of compounds such as NO_x, SO₂, Acid Gases, Mercury, and other toxic compounds are set by the National Emission Standards for Hazardous Air Pollutants (NESHAP) or Maximum Achievable Control Technology (MACT)

standards, as part of the Clean Air Act [25]. These limits are not hard emissions concentration limits that are broadly applied to all power plants, as power plant mixes in different regions perform differently with respect to available fuel type and economic considerations. Rather, a MACT standard is applied to individual facilities using a two-step process:

- Establishing a MACT floor using the emissions of currently operating sources as a baseline. For new facilities, this is at least as stringent as the best performing similar source currently in operation. For existing facilities, this is at least as stringent as the average of the top 12% of best controlled sources.
- Adjustment of emissions limits relative to the MACT floor depending on facility-specific constraints such as cost and fuel type availability.

Power plants must also obtain permits to operate from state authorities and local air districts in addition to federal requirements. The approval process for these permits often considers criteria pollutant emissions as permitting criteria, especially in non-attainment areas.

Certain states such as California have also set power plant emissions limits for greenhouse gases. In this region, Senate Bill 1368 [26] establishes that baseload generation that is either owned or contracted by publicly owned utilities must emit no more than 1,100 lbs. of CO₂ per MWh of generation.

1.2.3.2. Light-Duty Transportation Sector

The following represents sustainability-oriented goals which are specific to the light-duty transportation sector.

1.2.3.2.1. Increasing Fuel Economy of the Conventional Vehicle Fleet

Fluctuations in gasoline prices over the past decade have brought public attention to the fuel economy of the light duty vehicle fleet. Increases in gasoline costs have impacted consumer spending and created demand for more fuel efficient vehicles. In the U.S., recognition of the strong dependence of the transportation energy supply on imported crude oil has compounded recognition of the fuel dependence on the national scale. Strategies to address these concerns in the short-to-medium term timeframe are manifested in automakers producing more efficient vehicles and the mandating of the Corporate Average Fuel Economy (CAFE) standards. The progression of the average fuel economy for the short-wheelbase (SB) and long-wheelbase (LB) fleets from 1980-2010, as well as that for the average new passenger car and light-duty truck models from 1980-2012 in the U.S. are presented in Figure 18. Data for this figure is sourced from the U.S. Department of Transportation [27].

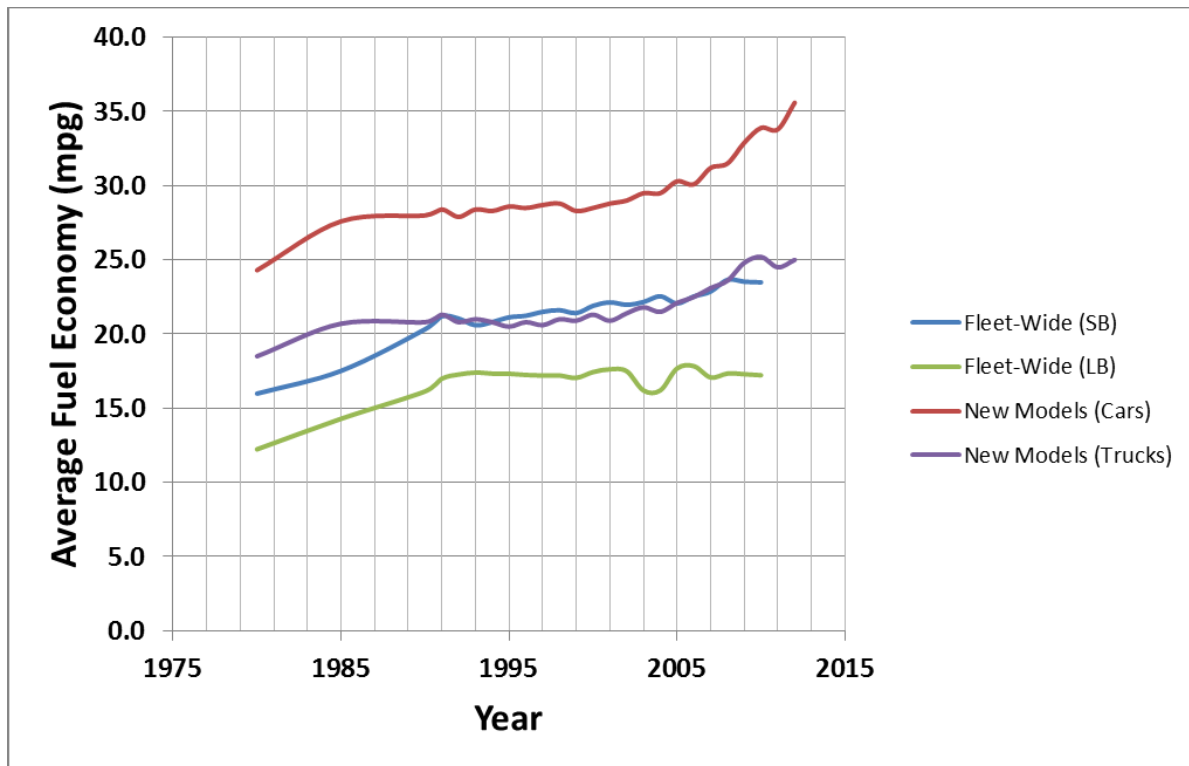


Figure 18 - Progression of Average Light-Duty Fuel Economy in the U.S. [27]

CAFE standards designate that the average fuel economy of the vehicle fleet produced by an automaker for a current model year must be equal to or above a certain level, taking into account vehicle footprint differences and other factors. Future proposals call for a CAFE standard of 54.5 mpg for light duty vehicles with a footprint of less than 42 square feet [28].

Increasing the fuel economy of the light-duty vehicle fleet contributes towards satisfying the holistic sustainability goals by reducing greenhouse gas emissions and securing the primary energy supply by reducing dependence on imported oil relative to a business-as-usual case.

1.2.3.2.2. Reducing Criteria Pollutant Emissions of the Conventional Vehicle Fleet

The transportation sector is responsible for the dominant share of emissions for many criteria pollutant types, due to the lack of access to large-scale exhaust cleanup systems and dependence on a single fuel type. Therefore, standards have been implemented to regulate the criteria

pollutant emissions levels of on-road vehicles at both national and state levels. These standards are continually updated to become more stringent with time to preserve air quality in the presence of increasing vehicle populations.

In the U.S., criteria pollutant emissions for the transportation vehicle fleet are regulated by the Environmental Protection Agency. The latest emission standards as of March 2014 are the Tier 3 emissions standards which are set to be phased in starting in 2017 and 2025 [29]. Compared to the previous Tier 2 standards, Tier 3 standards require a decrease in the sulfur content of gasoline, and set more stringent limits for the emissions intensity of non-methane organic gases, nitrous oxides, particulate matter, and evaporative emissions.

Certain states such as California has set criteria pollutant emissions standards for vehicles sold and registered within its territory which are more stringent than the national standards. Moving above and beyond the national standard was deemed necessary in California due to the unique issues with maintaining air quality that are specific to this region: a combination of unfavorable geography with very high vehicle populations. The current vehicle emission regulations for California are specified in the Low-Emission Vehicle III (LEV III) set of standards [30].

1.2.3.2.3. Shifting to Alternative Drivetrain Technologies

The light-duty transportation sector has historically relied on petroleum as the heavily dominant fuel type to meet motive energy needs. Given the nature of petroleum as a carbon-heavy fossil fuel, there are limits on the extent to which progress towards meeting the holistic sustainability goals can be obtained when relying on the internal combustion of petroleum products for motive power. While the short-to-medium term focus will be on improving the sustainability performance of the petroleum-fueled vehicle fleet, long-term solutions will require motive

propulsion systems to shift away from this fuel type. Some of the major alternatives will be discussed in Section 2.

The market availability and penetration level of alternative fuel vehicles such as battery electric and hydrogen fuel cell vehicles are still in their early stages as of 2014. Therefore, most areas do not have a large-scale policy which formalizes the goal to shift towards alternative fuel vehicles. One example of such a policy, however, exists in California as a Zero-Emissions Vehicle (ZEV) mandate, which sets a goal of having 1.5 million zero-emission vehicles on the road by 2025 [31]. ZEVs are defined as vehicles that do not emit any tailpipe pollutants from the onboard propulsion system, which by nature excludes petroleum-fueled vehicles.

1.2.3.3. Water Supply Sector

The following represents sustainability-oriented goals which are specific to the water supply sector.

1.2.3.3.1. Safeguarding and Improving Water Quality

Water quality standards and rules for the treatment and discharge of processed water streams into water bodies are highly regulated in the interest of protecting human health. In the U.S., these standards are set by the U.S. Environmental Protection Agency through the Clean Water Act [32] and the Safe Drinking Water Act [33]. The Clean Water Act regulates discharge of pollutants into water bodies by setting maximums for the allowable level of pollutants that may be discharged by a given facility. The specific regulations vary by facility type and location. Facilities are responsible for treating their effluent to meet these standards, and must obtain a permit through the National Pollutant Discharge Elimination System (NDPES) to legally discharge effluent into water bodies. Maximum limits for the amount of pollution that a water body can receive on a daily basis and still be considered safe to utilize are also specified by total

maximum daily loading (TMDL) calculations. Water bodies which have accumulated pollutant levels that are too high to be safe for exposure are considered impaired, and these bodies must be registered and reported to the EPA. The Safe Drinking Water Act regulates waters that are used for public drinking supply. This includes the entire supply chain from source water protection to the tap. In general, limits for the levels of contaminants in drinking water are set and/or required treatment techniques are mandated for the public water supply systems. Local water authorities are responsible for ensuring that these standards are met.

Moving forward, the implementation of sustainability-oriented options must comply with the framework set by the Clean Water Act and the Safe Drinking Water Act with regards to operation and life-cycle performance impacts on water bodies. These regulations may also be updated to account for new forms of pollutants that are present in water bodies due to novel technology deployment.

1.2.3.3.2. Diversifying the Water Supply Portfolio

Efforts to safeguard water quality are coordinated on a national scale, with sweeping regulations being passed by the federal government. Efforts to meet the goal of securing water resources, however, are more regional in nature since local water utilities are responsible for procuring water supplies to meet their demand and the portfolio of available supply or demand augmentation options are variable by region. Therefore, there is not a large-scale framework or set of regulations that are aimed at securing the water supply by diversifying the water supply portfolio to include new supply sources or reuse. There are, however, examples of localized efforts which include measures other than the traditional extraction from groundwater and surface water reservoirs to compose their respective water supplies. Some of these examples are described as follows.

The Orange County Water District (OCWD), located in Southern California, has traditionally relied strongly on groundwater resources to meet its water needs. This is common for water utilities in this region due to a dry local climate and dependence on imported water from the northern parts of the state. Due to the effects of groundwater depletion, the OCWD has implemented a groundwater replenishment system which incorporates water reuse [34]. Under this system, a percentage of the effluent from the wastewater treatment plant at the Orange County Sanitation District is diverted to a purification plant, which treats the water to higher standards that allow it to be used as primary water supply. This effluent is then piped and injected into the major groundwater aquifer which serves the county, and is considered as similar to naturally injected water in the aquifer. This process allows for a reduction in the net extraction of groundwater from the aquifer and acts to secure the water supply. The purification plant has a capacity of 70 million gallons per day.

Another example is the San Diego County Water Authority, which is also located in Southern California and is subject to the same dependencies for water supply as other areas in the region. This region has started construction of a seawater membrane desalination plant in Carlsbad, located in the northern part of San Diego County, as a means of securing the county's water supply under uncertain future conditions and depleting supplies from the Colorado River. This plant has a capacity of 50 million gallons per day and is expected to be online by 2016 [35].

1.3. Co-dependence of Sustainability Goals and Choosing Among Options

From the overview of driving forces which give attention to the issue of sustainability and efforts being implemented to set and meet sustainability goals, it becomes apparent that the challenge of rendering our society as sustainable requires contributions from changes in the design and

operation of different resource sectors and their key infrastructures. The development of individual resource sector sustainability goals has the benefit of being able to guide the direction of shifts in the design and operation of specific resource sectors. This is evident by the setting of policies which mandate or encourage shifts in individual resource sectors separately from one another. Analyses and efforts to meet these goals have involved a characterization of the different types of options associated with providing the service of a given resource sector, and choosing among them based on criteria including cost, technical potential, and others, considering impacts on infrastructure and related constraints to varying extents. This approach is represented graphically for the three sectors of electricity, transportation, and water supply in Figure 19:

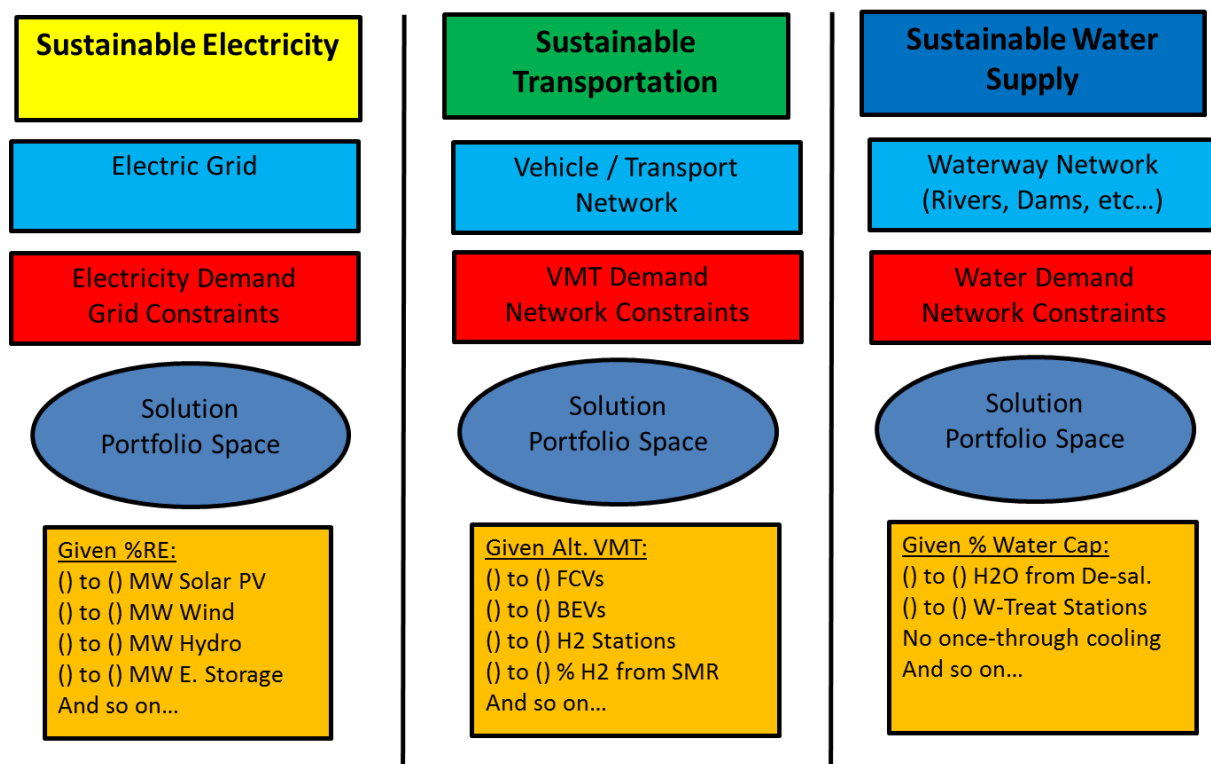


Figure 19 - Current/Historical Approach to Development of Pathways to Meet Sustainability Goals

This approach, while logical, has a major flaw in that it does not account for the fact that the emerging options that are being slated for deployment to meet the sustainability goals of individual resource sectors do not only affect the required design and operation of the infrastructure in that single resource sector. Infrastructures which have been historically isolated from each other may start to develop strong interactions and become strongly dependent on each other to provide their respective services in a sustainable manner. The deployment of a set of options to meet a sustainability goal in one resource sector may affect the ability of another resource sector to meet its individual sustainability goal. These interactions can be detrimental, where they hinder the ability of co-dependent resource sectors to meet their respective sustainability goal or provide their respective service, or synergistic, where they allow co-dependent resource sectors to make progress towards providing services and meeting their sustainability goals that could not have been possible in an isolated context.

Consider the electricity and transportation sectors as an example. Two promising alternative vehicle technologies – battery electric vehicles and hydrogen fuel cell vehicles – require significant amounts of electric energy either directly as motive fuel or to produce the fuel needed for these vehicles. Therefore, their deployment will impose an electric load of a particular temporal and spatial character that the electric grid must be able to accommodate in addition to providing electric service for stationary loads. This increases the total electric load energy on the grid, requiring more renewable capacity to be deployed to meet a given greenhouse gas emissions target. Vehicle deployment imposed an additional difficulty for the electricity sector to meet its individual sustainability goals, therefore this in itself is a detrimental interaction. However, the impact of this interaction can be partially or wholly offset by another effect of deploying these alternative vehicle technologies on the electric grid. If the vehicle charging load

or hydrogen production loads were able to be dispatched to follow the behavior of variable renewable resources, it can allow the grid to utilize carbon-free generation that it might otherwise not be able to utilize when high wind or solar capacities are installed. This reduces the need and associated costs of energy storage which would otherwise be needed to perform this function, therefore, this is a synergistic interaction.

There are many potential interactions between the impacts and effects of different sustainability-oriented technologies and management options which occur to different extents depending on the composition of the option portfolio. Additionally, there are many different options that could potentially be deployed in the different sectors. The current approach towards developing strategies to shift the design and operation of major resource sector to contribute towards meeting holistic sustainability goals has not sufficiently mapped out and taken into account the potential detrimental or synergistic interactions between sustainability-oriented options in co-dependent resource sectors.

It is important to understand that it is the holistic sustainability goals must be met by the entire combined system. The individual resource sector sustainability goals are proxies that if met, are believed to contribute towards meeting holistic sustainability goals, but these are not the end goals in and of themselves. Without taking into account these cross-sector interactions to sufficient detail by optimizing option sets in different resource sectors in isolation from one another, there is significant potential for detrimental unintended consequences to occur from the perspective of meeting holistic sustainability goals. It is not ideal to deploy sustainability-oriented options which allow one resource sector to meet its individual sustainability goal at the expense of hindering the ability of another sector from doing the same, or hurting the ability of

the combined system of all resource sectors to meet the holistic sustainability goals. Therefore, identifying these potential interactions, their cumulative impacts, and when they occur is critical for developing sound pathways to meet holistic sustainability goals and avoid unintended consequences in doing so. This approach allows insight for a holistically optimal technology deployment set, represented graphically for the three sectors considered in this dissertation in Figure 20:

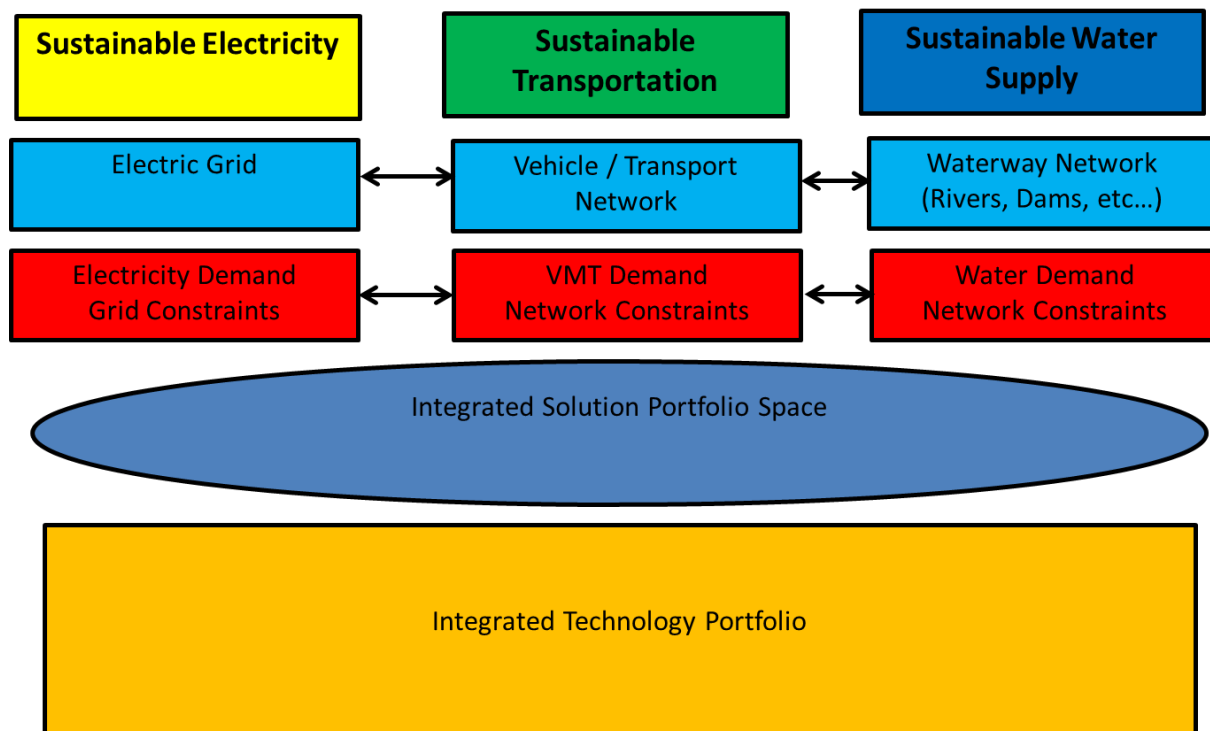


Figure 20 - Integrated Approach to Development of Pathways to Meet Sustainability Goals

This approach also allows the evaluation of current and emerging options on the basis of their performance and impact on the entire combined system. Certain options which may have performed universally well within the context of effects on a single resource sector can potentially be less effective in the combined scope or in certain conditions, and vice-versa. This

helps the dialogue of how to meet sustainability goals by giving a more complete understanding of the roles that different options are suited to fulfill and their performance in context.

1.4. Dissertation Goal

In the previous context, the goal of this dissertation is as follows:

- **To advise and optimize the deployment of sustainable technologies in an integrated electricity, light-duty transportation, and water supply system.**

In general, accomplishing this goal involves two aspects:

1. Characterizing the performance of current and emerging sustainability-oriented options in different resource sectors and
2. Identifying interactional synergies and interferences between these options while taking into account their impacts on co-dependent infrastructures in these sectors for the purpose of advising their deployment to most effectively contribute towards meeting holistic sustainability goals.

The steps taken to carry out these processes are formalized as objectives in the next section.

Overall, this dissertation aims to start an integrated framework for developing sound pathways for meeting holistic sustainability goals.

1.5. Objectives

A list of objectives has been developed to describe the tasks necessary to achieve the goal of this work. These objectives are listed as follows:

1. **Understand the motivation behind sustainability goals in major resource sectors.**
 - a. Electricity Sector

- b. Transportation Sector
 - c. Water Supply Sector
- 2. Characterize the technical operating constraints of major resource sectors.**
 - a. Electric Grid
 - b. Vehicle Usage and Fueling Infrastructure
 - c. Water Supply, Conveyance, and Treatment
- 3. Develop a modeling platform that captures the inter-dependency of the key infrastructures of major resource sectors and the sensitivity of their operation to extra-sector technology options.**
 - a. Electric Grid Model - HiGRID
 - b. Light-Duty Transportation – PEV and FCV usage behavior and fuel chain
 - c. Water Reservoir Network
- 4. Characterize the capabilities of technological options for meeting individual sector sustainability goals**.**
 - a. Renewables and Complementary Technologies
 - b. Water Supply / Demand Stabilization Measures
- 5. Use the developed platform to assess the capabilities of technological options for meeting holistic sustainability goals within constraints while capturing relevant synergies and mapping out the option portfolio space.**
 - a. Electricity and Transportation
 - b. Electricity and Water Supply
 - c. Electricity-Transportation-Water Supply System

6. Advise the deployment of technological solutions in each sector to most effectively contribute to satisfying holistic sustainability goals.

******An individual resource sector assessment of the light-duty transportation sector was not performed. This was decided since the major alternative options considered here depend strongly on the electricity sector as part of their fuel supply chain. A spanning of the option map for both the electricity and transportation sectors is performed in Objective 5, which will include all relevant combinations of the electricity sector option shifts for each relevant transportation option combination. Therefore, performing a separate light-duty-transportation-only evaluation with a fixed electricity sector option mix was deemed redundant.

This work will use the state of California as the primary system of analysis. California is a prime choice for this type of study due to its access to a diverse array of sustainability-oriented options in all three major resource sectors, the presence of high populations and therefore resource demands, and its progressivity in setting sustainability-oriented targets for major resource sectors relative to the remainder of the U.S. at current. These characteristics allow a wide range of options and effects to be evaluated, which more readily enables lessons learned to be transferred to the planning of other systems.

Chapter 2: General Background

This section presents a general background on the operations of key infrastructures in the electricity, light-duty transportation, and water supply sectors, as well as an overview of the different sustainability-oriented options available for deployment in each sector. This background helps to frame the scope and discussion of the study. Note that this section is not the literature review for the dissertation analyses. Literature reviews will be presented for each of the component studies at the beginning of their respective sections.

2.1. Infrastructure Operations and Constraints

The following is an introduction to the operations and related constraints of key resource sector infrastructures, as relevant to the analyses in this study. Since California is the primary system for this study, much of the discussion is relevant to this region.

2.1.1. The Electric Power System

To contribute towards the meeting sustainability goals from standpoint of electricity, novel technologies and management options must be integrated into the electric power system. For this process to occur smoothly, it is important to have basic knowledge of how the electric power system is designed and operated. With this knowledge, one can understand the effect of integrating promising options on the system and recognize the changes in system operation and design that may be required to make such integration possible.

This section is aimed at giving a high-level description of the electric power system by describing the major components, entities, and operations of the system to provide electric service.

2.1.1.1. Major Components of the Electric Power System

The electric power system is the infrastructure of mechanical and electrical components which make electricity service possible. In its most basic form, the electric power system consists of three major components:

- **Generation:** Provides electric energy from conversion of various primary energy forms
- **Power Delivery:** Moves electric energy from the point of production to the point of consumption
- **Load Demand:** Consumes electric energy to perform various functions

These three components are presented schematically in Figure 21:

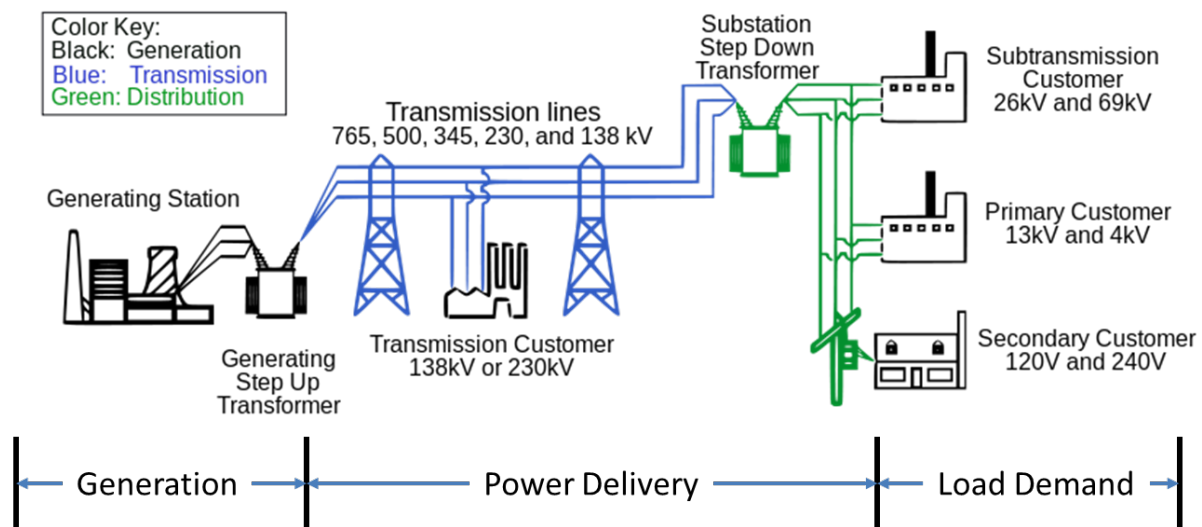


Figure 21 - Three major components of the electric power system. Schematic from FERC [36]

At all times, the system must be **balanced**, meaning that just enough electric power must be produced to meet the load demand. The load demand changes with time, and generation must produce enough electric power to satisfy the load demand at all times within tight margins.

Additionally, the power delivery network must be capable of moving the required amount of power from generation to load. These three major components are described here.

2.1.1.1.1. Generation

The generation component is responsible for producing the supply of electric power in real-time, and change its production as the required supply changes with time. This process is carried out through various energy conversion devices called power plants. Power plants take in energy in various forms and convert it to electric energy, producing usable electric power by using a set of mechanical, thermal, chemical, optical or nuclear processes. Electric power refers to the rate at which energy is converted into electric form. Power plants can be categorized in two ways: by fuel type and by operation.

2.1.1.1.1.1. Power Plant Types by Fuel Input

The input energy to a power plant can take many forms, including but not limited to:

- Solid fuels such as coal, biomass, or fissionable nuclear material
- Gaseous fuels such as natural gas or biogas
- Liquid fuels such as petroleum-based products
- Direct heat from the Earth's crust in the case of geothermal power
- Kinetic energy in the air masses in the case of wind power
- Electromagnetic radiation in the case of solar power
- Gravitational potential in the case of large hydropower

These input energy forms can be classified according to whether they depend on utilization of a finite resource. Coal, nuclear material, natural gas, and petroleum resources exist in finite amounts in nature and are not replenished quickly enough compared to the rate of use. When these fuels are utilized in a power plant, the availability of the resource decreases. These input energy types are classified as non-renewable resources. By contrast, other input energy forms utilize a resource that is continually replenished on short timescales. The sun continually provides electromagnetic radiation for solar power. The earth's core continually provides heat for geothermal power. Recurring weather patterns due to differential heating interacting with local geography provides kinetic energy in air or water masses in the case of wind and hydropower. Finally, electromagnetic radiation from the sun also provides the energy necessary to grow biomass and produce biogas. Therefore, solar, wind, geothermal, hydropower, biogas and biomass resources are classified as renewable resources.

The major processes used to convert these input streams to electric power can also be used to classify major power plant types.

Thermal power plants convert input energy into thermal energy. The produced thermal energy is used to drive a turbine cycle that converts it to mechanical energy by expansion through a turbine or reciprocating engine. Finally, an electric generator converts the mechanical energy in the spinning turbine or reciprocating pistons to electric energy. The production of thermal energy can be achieved in a number of ways including but not limited to:

- Combustion of a solid, liquid, or gaseous fuel.
- Concentrating solar radiation (solar thermal plants).

- Absorbing heat from the Earth's crust (geothermal plants).
- Fissioning of radioactive material (nuclear power plants).

There are three primary types of simple thermal power plants. A simple thermal power plant is one that uses a single power cycle, as opposed to a combined cycle thermal power plant which uses multiple power cycles. A power cycle is a set of processes that a working fluid undergoes to receive input energy and convert it to electric energy after which it returns to its original state or is expelled into the environment.

A **gas turbine** (Brayton) thermal plant is one that utilizes internal combustion to produce heat. These plants include natural gas- and biogas-fueled installations. Currently, natural-gas fired thermal power plants constitute the vast majority of electricity generating resources in California by capacity [37]. At these facilities, air is used as the working fluid and is taken from the surroundings using a compressor. The fuel is injected in and combusted with this working fluid and flows through the turbine. After passing through the turbine, the working fluid is exhausted to the atmosphere after passing through any existing emissions control equipment. A schematic of a simple gas-turbine power plant cycle is presented in Figure 22:

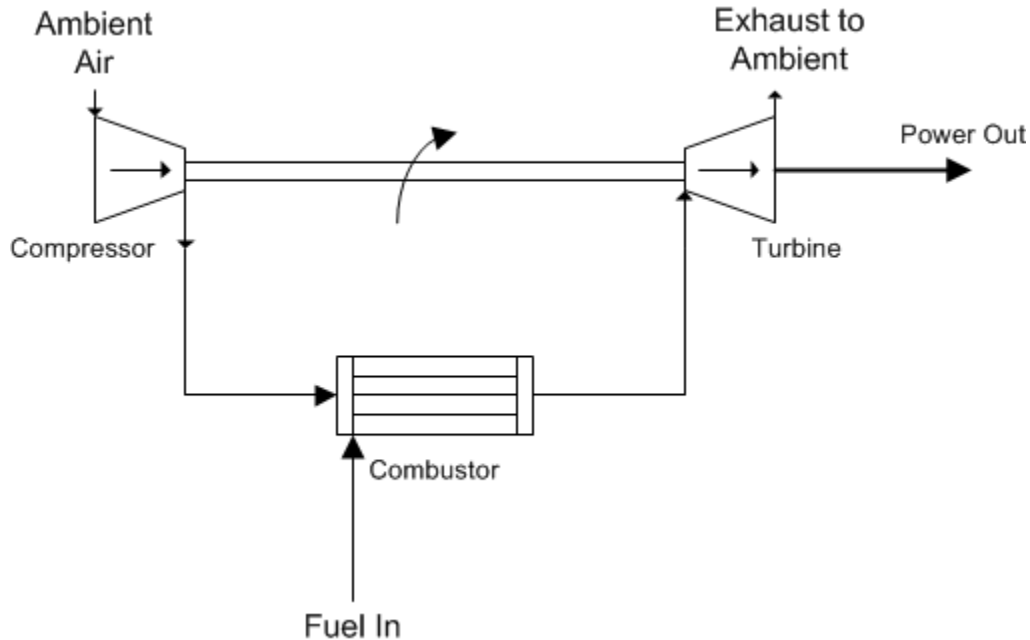


Figure 22 - Simple Gas-Turbine (Brayton) Power Plant Cycle

A **steam turbine** (Rankine) thermal plant is one that utilizes external combustion to produce thermal energy. These plants include, coal, biomass, and nuclear plants. Water is typically used as the working fluid and is circulated in a closed loop by a pump, though other fluids can be used. This thermal energy is then transferred to the water via a heat exchanger to convert it into high temperature steam before it flows through the turbine and expands to convert thermal energy into mechanical energy. The working fluid is then cooled and condensed via a heat exchanger that transfers the remaining thermal energy to a separate fluid as part of a cooling system. The condensed working fluid is then re-circulated to the pump to restart the cycle. A simple steam turbine power plant cycle is presented in Figure 23:

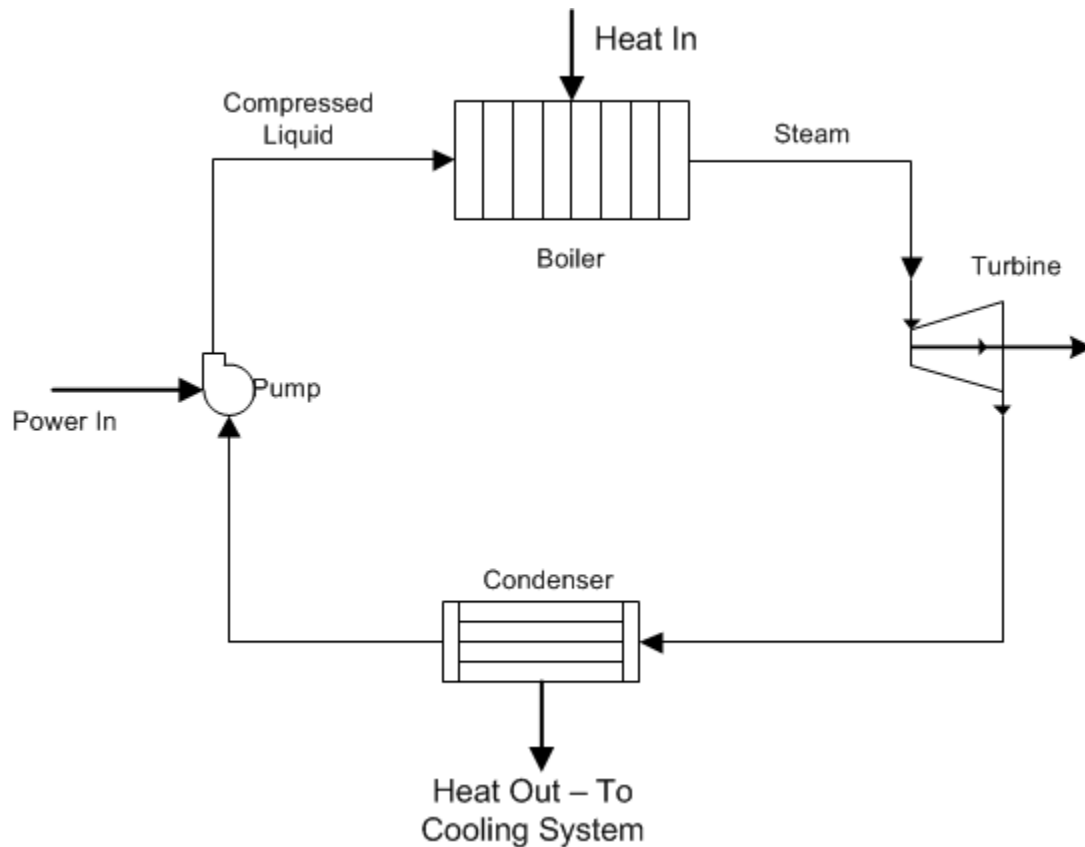


Figure 23 - Simple Steam Turbine (Rankine) Power Plant Cycle

A **reciprocating engine** thermal plant is one that utilizes internal combustion to produce heat, but instead of using a turbine to convert the thermal energy to mechanical energy, a reciprocating piston engine is used. These types of plants are operated on liquid fuel, such as diesel, and are used mostly for backup power generation instead of primary power generation.

Additionally, a **combined cycle** configuration can be used to increase the efficiencies of the conversion from primary energy input to usable electric energy. These power plant types use the thermal energy rejected from one power cycle as the energy input to another power cycle. A typical configuration uses the exhaust of a gas turbine cycle as the heat input to a steam turbine cycle. This increases the power output of the plant for a given fuel input. A simple schematic for a gas turbine cycle combined with a steam turbine cycle is presented in Figure 24:

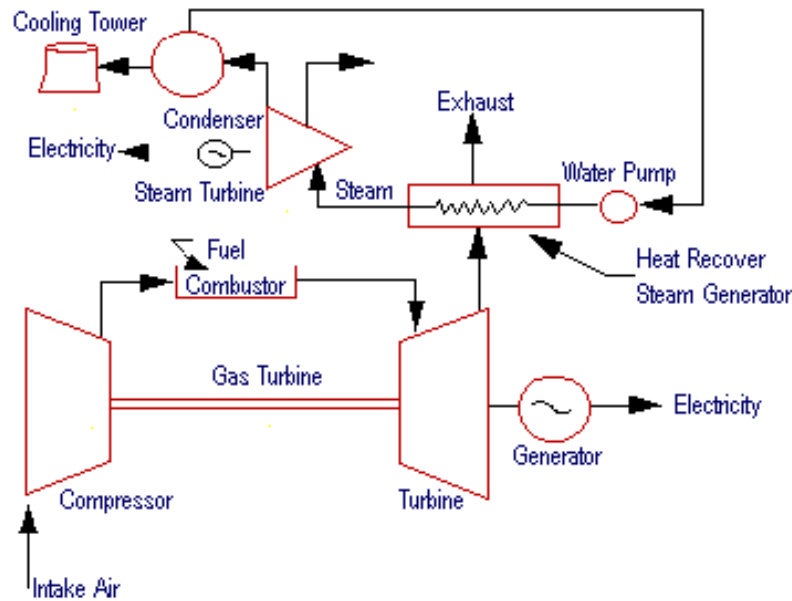


Figure 24 - Simple Schematic of a Combined Cycle Power Plant

In addition to thermal power plants, other power plant types are utilized to convert input energy to electric energy without first converting it to thermal energy. These non-thermal power plants rely on different mechanisms as described below:

Hydropower plants convert kinetic energy present in flowing water to mechanical energy by using it to drive a turbine, which then drives an electric generator to convert it to electric energy. In the case of small hydropower plants (less than 30 MW capacity), the turbines are inserted directly into flowing rivers and produces power in proportion to the stream flow. For large hydropower plants, dams are built over large height differences on a river to take advantage of gravitational potential energy differences. When water is allowed to flow, the gravitational potential energy is converted to kinetic energy and the process is similar to small hydropower.

Photovoltaic (PV) plants convert solar radiation directly into electric energy in direct current (DC) form using the photovoltaic effect. An electrical inverter converts the energy from direct current to alternating current (AC) form, which can be placed onto the power delivery network.

Wind power plants convert the kinetic energy in moving air masses to usable kinetic form by use of a wind turbine. The spinning turbine drives an electric generator to produce electric energy in the form of AC. The same principle applies to tidal power plants which utilize ocean currents.

2.1.1.1.1.2. Power Plant Operating Constraints

The diverse nature of fuel types and energy conversion technologies causes different power plant types to have different operating limitations. This applies to different technologies within and across the categories described in the previous section. An overview and short description of these operating limits for different fuel types are described here.

Efficiency Limitations

The percentage of the input energy that is converted to a useful electric form is limited theoretically by thermodynamics and further practically by losses in the utilized equipment.

Efficiency in this case is defined as the amount of useful electric energy extracted from a given amount of input energy. For any process, this figure cannot be greater than 100 percent.

Thermal power plants as a whole are theoretically limited by the Carnot efficiency. This is a result of thermodynamics and a function of the difference between the maximum (heat addition) and minimum (heat rejection) temperatures within which the plant operates. Larger differences between these temperatures allow thermal power plants to reach higher efficiencies. Other thermodynamic limits also apply to each of the components in a thermal power plant such as

compressors/pumps, turbines, combustors, and the like. Practically, efficiency decreases result from irreversibilities in the equipment utilized. Examples include but are not limited to:

- Friction in moving components and pressure drops in pipes with moving fluids.
- Heat loss in high temperature components such as combustors and turbines.
- Limitations on the tolerance of materials. For example, a restriction on combustor (maximum) temperature due to turbine blade material thermal limits prevents operation at higher efficiency configurations.
- Aerodynamic considerations in the compression and expansion of working fluids.

Currently, a typical simple-cycle thermal plant has efficiency between 25-40 percent depending on the technology used. More complicated plant configurations such as combined-cycle plants can have efficiencies up to 60 percent [38, 39]. These limitations apply regardless of input fuel type in this case, but may apply to different extents depending on fuel type.

Hydropower plants are generally very efficient since from a theoretical standpoint, the conversion of gravitational potential to kinetic energy is lossless. Practically, however, plant efficiency still decreases slightly due to friction in the moving turbine components and the electric generator. A typical large hydropower plant is just under 90 percent [40].

Wind power plants are theoretically limited in efficiency by aerodynamics. Further efficiency limitations arise due to the turbine blade materials. At high wind speeds, wind turbine blades are pitched to keep the turbine rotating at a constant speed even as the wind speed increases. This causes the extraction of energy to remain constant even as more energy becomes available for use. This practice is used because the turbine materials cannot structurally withstand rotation at

higher speeds. Due to this, wind turbine performance is typically measured by **capacity factor** rather than efficiency.

Solar Photovoltaic (PV) plants are theoretically limited in efficiency by thermodynamics.

Practically, PV efficiencies are limited by materials selection and parasitic losses such as the conversion of electric energy from DC form to AC form and losses in the sun-tracking system.

The efficiency of a typical, Silicon-based photovoltaic panel is about 12 percent [41].

Part-Load Operation Limitations

Depending on the behavior of the load demand that these power plants must satisfy and the need for extra capacity due to reliability concerns, certain power plants are often called upon to operate at reduced power output. This is called **part-load operation**. For example, a power plant may operate at 90 percent power such that the remaining 10 percent can be used for supporting the electric power system in the event of a contingency. A power plant may also be requested to reduce its power output to keep the system balanced in the event of a decrease in the load demand.

Power plants are typically designed to operate at a particular power output level and within a certain range around that level. This power level is called the ‘design power’ or ‘rated power’. Operating with a power output much lower than this level is called a severe part-load operating condition. This is especially applicable to thermal power plants due to the operating ranges of the components of the system. For a given thermal power plant, however, there are limitations on how low its power output can be decreased below the rated power level. An explanation of some of those limitations is presented here.

Gas turbine thermal plants have a minimum power output level, due to a number of factors, including the need to minimize air pollutant emissions and maximize efficiency. An example of a part-load heat-rate curve for a two-turbine combined cycle power plant is presented in Figure 25 [38]. Note that heat rate is the reciprocal of efficiency.

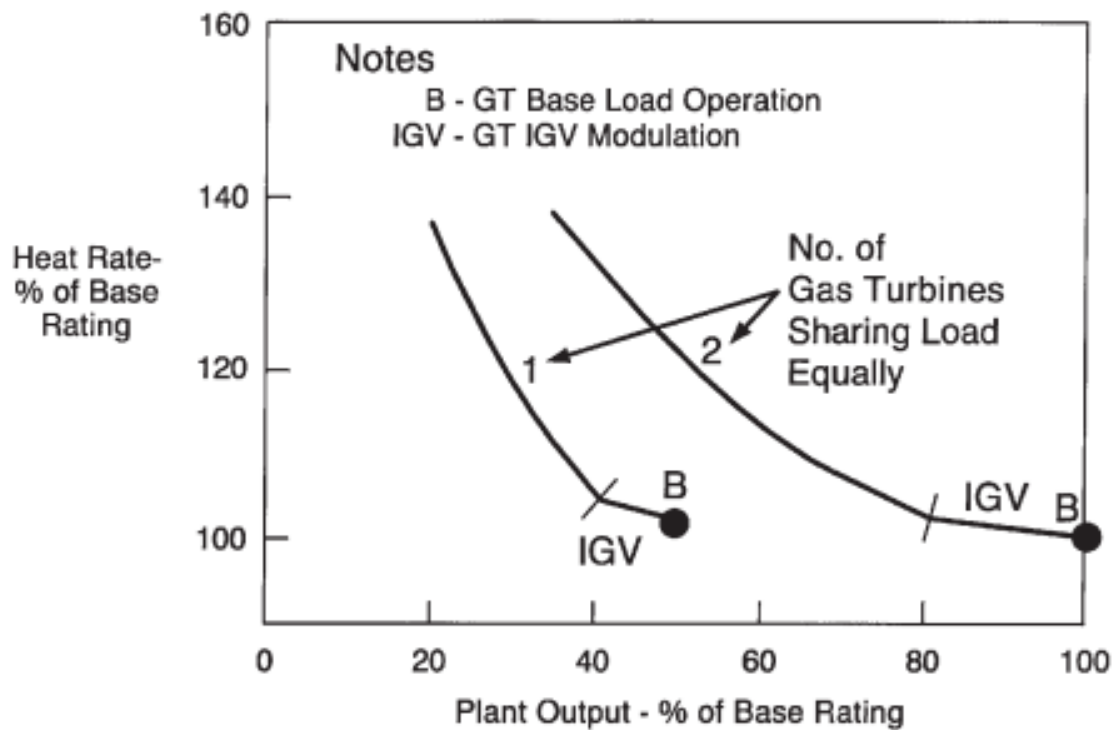


Figure 25 - Example Part-Load Heat Rate Curve [38]

Emissions of criteria pollutants such as NO_x, CO, and particulate matter (PM) increase significantly when the power output is below a certain level [42]. For a gas turbine thermal plant to reduce its power output, it must reduce its fuel and air input flows. Due to the nature of compressor and turbine operation, there is a limit on how much the air flow can be reduced before the compressor surges. Therefore, the fuel input must be reduced to lower the power output further while maintaining the same air input. This changes the combustion properties

(such as air-to-fuel ratio) such that the combustion process produces more pollutant products. Operating in such a manner may cause a power plant to violate air pollution regulations.

The efficiency of a gas turbine thermal power plant is reduced at part-load. As the power output is decreased from the design power level, the efficiency decreases slightly down to a certain fraction of the design power level, below which it decreases significantly. This occurs since the power output of a thermal plant is determined by its airflow and its efficiency. The efficiency of a thermal plant is strongly dependent on the temperature of the working fluid entering the turbine, which is linked to the combustion temperature. A higher combustion temperature indicates a higher efficiency for a given plant configuration. At slight part-load conditions (typically 80 percent of rated power or higher), reductions in both airflow and fuel input are used to reduce the power output while the combustion temperature is maintained, causing the efficiency to only drop by a small amount. At severe part-load conditions (typically less than 80 percent of rated power), the airflow is maintained but the fuel input is reduced, resulting in a lower combustion temperature and reduced efficiency [38, 43]. Operating in such a manner may be uneconomical for the power plant.

Steam turbine thermal plants also have a minimum power level. These plants, however, have different factors affecting emissions increases and efficiency reductions at reduced power output. The emissions of a steam turbine power plant do not increase as dramatically as that of a gas turbine thermal plant at part-load because the fuel and air input to the external combustion process can be reduced and emissions maintained at low output levels. The efficiency of a steam turbine thermal plant operating at part-load is reduced from the creation of a pressure loss in the working fluid between the boiler and turbine. Finally, an additional factor affecting the

minimum power output for steam turbine plants is the utilization of two phases of water: liquid water and steam. The turbine is designed to operate on steam and will be damaged if liquid water forms within its stages. Therefore, there must be sufficient thermal energy produced in the combustion process and transferred to the water such that it is converted to steam before entering the turbine. Additionally, the steam must be of a high enough temperature such that it does not condense to liquid water while energy is being extracted from it inside the turbine. This sets a lower limit for the reduction in fuel and air inputs to the combustion process, and therefore a lower limit on the power output of the plant as a whole.

Hydropower plants do not have a physical limitation on the extent that these units can reduce their power output from rated levels. Power output from a hydropower plant is controlled by altering the water flow rate from the upper reservoir in a dam. The practical operation of these plants, however, is also constrained by the requirement to meet local water supply needs and flood control concerns.

Wind and Photovoltaic power plants are not controllable by nature. While undesirable, however, these plants can be operated to reduce their power output if required. Wind power plants can pitch the blades on individual wind turbines to absorb more or less of the kinetic energy present in the wind at any given time. Photovoltaic plants can either orient panels to a non-optimal tilt and azimuth angle during different times of the day or use power electronics to change its voltage and current setting off of the maximum power configuration.

Power Ramping Limitations

To continually satisfy a load demand, power plants must also be able to change power output quickly enough to follow the load demand which varies in time. The change in power output

that a power plant can produce in a fixed time interval is called the **ramp rate**, which is a measure of ramping capability. For example, if the load demand decreases by one GW in a period of 30 minutes, the aggregated power plant fleet must be capable of decreasing its power output by the same amount in the same amount of time to keep the load demand satisfied. This applies to individual power plants as well.

Different power plant types are composed of different components that interact with each other in different ways depending on fuel type. This causes certain types of power plants to exhibit faster power ramping capability than others. The limitations on power ramping capability for different types of power plants are discussed here. Since these limitations have significance for the response of power plants to a changing load demand, only controllable power plant types will be discussed. The power ramping characteristics of variable renewable resources is discussed in Section 2.2.

Steam turbine thermal plants typically have the slowest ramping capabilities. For example, the majority of the steam turbine-based power plants in California have ramp rates of 1-5 MW/min or slower [44]. This is due to the use of external heating. For a steam turbine power plant to change its power output, the thermal energy produced from external combustion or fission must be increased or decreased accordingly. Due to the use of a heat exchanger / boiler, there are limitations on how quickly this increase or decrease can occur. If an increase in thermal energy release occurs too quickly, the vessel may experience very high temperatures on one side and comparatively low temperatures on the other side. This occurs because the released thermal energy may not transfer quickly enough through the boiler vessel and to the working fluid. This large temperature difference can stress the vessel material and cause it to fracture. A similar

principle applies to a decrease in thermal energy release. Additionally, coal or biomass fuels require longer time periods to combust compared to gaseous fuels. For the case of nuclear power, there is also the additional concern of controlling the nuclear reaction and maintaining safe conditions for the reactor [45]. Smaller steam turbine thermal plants or units using natural gas as the fuel input can have relatively faster ramping capabilities compared to larger plants, but are still slower than gas turbine thermal plants.

This limitation has rendered fuel types that require steam turbine-based power cycles to be operated with a relatively constant power output, with changes in power output occurring over long periods of time. This includes primarily coal, biomass, and nuclear power. Geothermal power also typically operates in this manner since the thermal energy input is not controllable. This type of operating scheme is called “base-load” operation and is discussed later in this section.

Gas turbine thermal plants typically have fast ramping capabilities, especially in simple cycle configurations. The current California fleet has many gas turbine units with ramp rates of about 10 MW/min or higher [44], and advanced gas turbines are reaching ramp rates of 50 MW/min [39]. To change its power output, the thermal energy input to the working fluid must be changed. Since these plants use internal combustion, additional thermal energy from the combustion reaction is immediately transferred into the working fluid. Temperature differences within the combustion chamber are also not as severe of an issue compared to a boiler since heat addition occurs internally and thermal energy does not have to spread through the combustor housing to enter the working fluid. Additionally, the gaseous and liquid fuels used in these systems tend to combust quickly. The ramping limitations of gas turbine thermal plants are due

to the inertia of the compressor and turbine components and the need to maintain preferable combustion conditions.

This property has allowed fuel types that use gas turbine-based power cycles to be operated with variable power output. These power plants adjust their power output in response to changes in the load demand with time. The ability to change power output quickly also makes them suitable for operating with reserve capacity.

Combined cycle power plants also typically have ramp rates that are slower than simple gas turbine plants but faster than steam turbine plants. Some of these units can ramp quickly over a certain range of power levels, but slowly in others. This occurs because the gas turbine component can ramp quickly, while the steam turbine component is allowed to lag behind. These power plants also provide load following and reserve capacity, but at slightly slower timescales than pure gas turbine plants. Natural-gas fired power plants in combined-cycle configuration currently form the bulk of the load-following power plant fleet in California.

Hydropower plants also have fast ramping capabilities. About half of the hydropower plants in the current California power plant fleet have ramp rates greater than 20 MW/min [44]. To change power output, a hydropower plant simply must allow more or less water to flow by opening or closing floodgates. The primary limitation on hydropower plants is due to flood control. A quick increase in power can cause excess water to flow downstream in a short period of time, possibly causing floods.

This property has allowed hydropower plants to provide a significant fraction of the load-following and reserve generation capacity in California, similar to gas turbine plants.

Power Cycling and Power Plant Start-up Limitations

The load demand tends to exhibit a repeatable pattern. For example, consider a common load pattern occurs on the daily timescale: the load demand is low in the early morning, rises during the day and early evening, and drops in the nighttime hours. This repeated increasing and decreasing is called **cyclic** behavior. Cyclic load behavior can also occur on shorter timescales and generation must be able to keep up with this behavior to keep the load demand satisfied.

Repeated increasing and decreasing of power output can have adverse effects on power plants, particularly thermal power plants. If the load demand cycles between very high and very low power levels in short periods of time, this can also require power plants to start up and shut down frequently. The limitations of power plants in withstanding multiple power output or start-up/shut-down cycles are discussed here.

Thermal power plants are strongly affected by power output and start-up/shut-down cycling. Adverse effects include decreased reliability, decreased plant life, increased maintenance requirements and associated costs.

These effects are primarily caused by thermal fatigue and temperature differences. **Thermal fatigue** is the stressing of a material due to repeated heating and cooling. Materials typically expand when heated up and contract when cooled down. When a material undergoes enough of these expansions and contractions, it can fail. For example, during a power increase, the additional heat input temporarily increases the temperature of the boiler or combustor and it takes some time for the flow rate of the working fluid to be adjusted to bring the temperature down to the design operating point. The opposite occurs for a power decrease. When cycling

power output, the components of a thermal plant continually fluctuate in temperature, wearing the materials of those components.

This effect is more extreme with start-up / shut-down cycles. During these events, the minimum and maximum temperature of each cycling event can become very large, intensifying the effect of thermal fatigue. During shut down, all components of the power plant are cooled down significantly. The extent of the cool down depends on how long the plant remains offline.

These effects apply to all types of thermal power plants. The specific type of thermal power plant determines which components are most likely to fail prematurely and therefore require the most attention. From a cost perspective, steam turbine based thermal plants have higher costs associated with cycling behavior [46].

Typically, thermal plants are designed only to withstand a set number of start-up/shut-down cycles and operating hours before needing an overhaul or replacement. A typical load-following gas turbine undergoes about 300 starts per year [46, 47].

Additionally, thermal power plants use additional fuel and produce criteria pollutant emissions during a start-up event. The pollutant emissions of a start-up event are generally very high, and local air districts have imposed limitations on how often a power plant can start up due to these emissions concerns. Fuel is also required to start up a power plant before it begins producing useful power.

Hydropower plants do not have the same vulnerability to cycling behavior compared to thermal plants. These plants do not have to deal with thermal fatigue. Wear on plant components is primarily due to contamination or abrasion with particles and debris in the water stream.

2.1.1.1.1.3. Power Plant Type by Operation Mode

The diverse set of operating limitations for different types of power plants implies that some types are more suited for fulfilling certain roles in meeting the load demand than others. This section re-classifies the power plant types described prior by the manner in which they are typically operated on the electric power system. An example time-series plot showing the operating profile of different power plant types is presented in Figure 26:

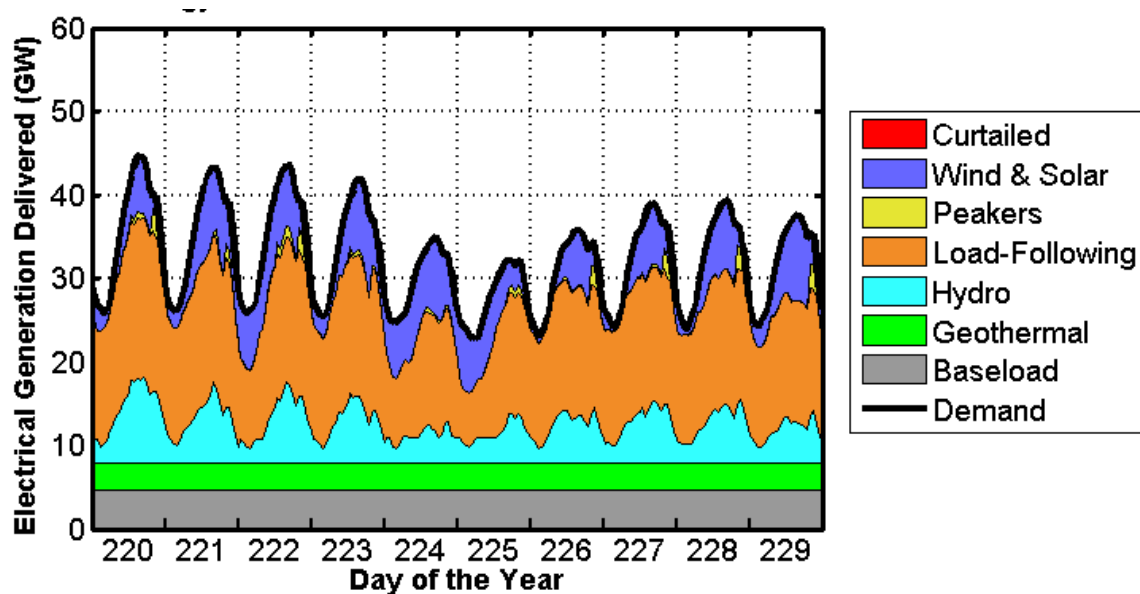


Figure 26 - Timeseries Plot of Different Power Plant Types by Operation Mode

Base load power plants are those which typically operate with a constant or near-constant power output at or near their design power output. These power plants typically do not respond to load changes and are mostly incapable of doing so to a large extent. The main role of these power plants is to provide bulk power for meeting the load demand. The capacity of base load power plants operating in the total power plant fleet on a given day is typically just under what is predicted to be the minimum load for that day. Base load power plants require long periods of time to start-up or shut-down.

Steam turbine-based thermal plants are operated as base load power plants. This includes mostly **coal, nuclear, biomass and geothermal** power plants, but many older gas fired power plants are also operated in this manner. The physical limitations for ramping, cycling, and part-load operation make these power plants suitable for this type of operation.

Base load power plants typically provide the cheapest costs of electricity. The guarantee of constant operation results in high annual capacity factors. Typical coal, nuclear and geothermal plants have capacity factors of about 80 percent, 86 percent and 90 percent respectively. The **capacity factor** is defined as the ratio of actual electric energy obtained from a power plant to the electric energy that would be obtained if the power plant had operated at maximum power for the whole year. This is also equivalent to the ratio of the average power to the rated power, and is an important indicator of the price of electricity. The average power is an indicator of production and therefore sales and revenue. The maximum power is an indicator of the size of the power plant and therefore capital investment and fixed operation and maintenance costs. A power plant with a higher capacity factor is able to produce more power over a given period of time and bring in more revenue per unit of capital and fixed operation and maintenance investment. This allows owners and investors in the plant to recover their investment quickly, allowing electricity to be sold at a low rate from these plants and still be profitable for the investors. Coal and nuclear power plants also benefit from relatively low fuel prices resulting in low operating costs. This results in coal and nuclear power exhibiting among the lowest cost of electricity. This principle also applies to base loaded renewable power such as biomass and geothermal power [48, 49].

Load following power plants are those which typically operate with a variable output that changes with the load demand. The main role of these power plants is to meet the variable portion of the load demand. These power plants also provide reserve capacity due to their ability to increase power in a short amount of time to provide support in case of a contingency. The capacity of load-following power plants operating in the total fleet on a given day is the difference between the base load capacity and the predicted maximum load for that day with a margin for reserve capacity. With current operating rules, load-following power plants typically have a minimum operation time of 8 hours when brought online on average [50].

Gas turbine-based thermal plants and hydropower plants are typically operated as load-following power plants. For thermal plants, this includes mostly **natural gas and biogas** fueled power plants. The ability to provide relatively quick power ramping, withstand numerous power cycles, and operate at part load make these power plants suitable for this type of operation. Since these power plants meet a large portion of the load demand, **combined cycle gas turbine power plants** are typically used due to their higher efficiencies over simple cycle plants.

Load following power plants have higher costs of electricity than base load power plants. Since these plants often operate at part load, their capacity factor is not as high. A typical capacity factor for a combined-cycle load following plant is about 70 percent [50]. This indicates that electric energy must be sold at higher rates for the plant to be profitable to investors in a short period of time. The cycling behavior of load following power plants also contributes to costs associated with increased component wear [46, 48].

In California, a large portion of the load-following power plant fleet is also composed of **hydropower plants**. These power plant types are very flexible in that they can vary and cycle their power output quickly and operate at part load with minimal damage or derate in efficiency.

Peaking power plants or “Peakers” are those which typically only operate to meet high loads beyond the capacity of base load and load following power plants. These plants are brought online with short notice when the actual load exceeds the forecasted load or scheduled capacity for a particular time period. Peaking power plants in California typically have a minimum operating time of 2 hours when brought online on average [50].

The most important capability for a peaker is low start up time and very high ramping capability. This limits peakers to be composed of **simple cycle gas turbine thermal plants**.

Electric energy obtained from peaking power plants is typically very expensive. These power plants have very low capacity factors on the order of 5-10 percent since they only operate when needed. These units also exhibit low efficiencies and relatively high fuel prices. If possible, load-serving entities would prefer to not have to purchase power from these plants unless absolutely needed.

2.1.1.1.1.4. Power Plant Cooling Systems

The electricity sector depends on the supply of water to operate key elements of the infrastructure such as thermal power plants. As the electric load demand grows with population and the resource mix shifts to a different composition, the water requirements of the electricity sector may change. An overview of these dependencies is discussed here.

The water requirement for the cooling of thermal power plants accounted for 27.6 percent of total water withdrawals in California in 2005 [40]. Since the majority of these power plants are

located on the coast, cooling of thermal power plants did not affect freshwater withdrawal since these units exclusively relied on saline water. Due to the effects of coastal power plant use of saline water for cooling on local marine environments, measures are in place to retire and replace these power plants with alternative cooling systems [40]. In non-coastal regions, however, water withdrawal for power plant cooling is also a large portion of the total water withdrawal, but these units must use freshwater.

It should be noted that only steam-turbine thermal power plant cycles require water for cooling. Since the working fluid operates in a closed-loop, it must be cooled by an external system such that it can be condensed and be suitable for pumping. Gas-turbine thermal power plants continually exhaust working fluid to the environment and take in new working fluid from the atmosphere to operate. This new working fluid is already at cool temperatures and the system does not need to be cooled.

Combined-cycle thermal power plants still require cooling since these plants use both a gas-turbine and steam-turbine cycle. These units, however, have lower cooling requirements than a stand-alone steam-turbine cycle. The gas-turbine component produces the majority of the power output and allowing the steam-turbine component to be relatively small in size, reducing cooling requirements.

A brief description of major cooling methods for steam-turbine based power plants is discussed here.

- **Once-Through (Open-Loop) Cooling:** This refers to a system where water is taken in from a river or ocean, heated by absorbing thermal energy from the steam-turbine cycle, and immediately ejected back into the river or ocean from which it was extracted. This

process requires significant water withdrawals to operate, however it does not contribute significantly to water consumption since the extracted water is immediately returned to the reservoir. For example, an average nuclear power plant in the U.S. using once-through cooling withdraws 44 times as much water as the same size of power plant using a cooling-tower based system [51]. The extracted water is also returned at a higher temperature than its surroundings, which can severely disrupt the balance of local aquatic ecosystems. In California, once-through cooling power plants are placed on the coast and use saline water. If these plants used once-through cooling with freshwater as is the case in other parts of the U.S., it would significantly add to the freshwater demand and strain water resources. Due to these effects, measures are in place to retire and replace these power plants with alternative cooling systems.

- **Cooling Tower:** In this system, water is taken in either from a water reservoir directly or supplied from the water infrastructure to absorb thermal energy from a thermal power plant. Instead of returning this water to its source, however, it absorbs thermal energy until it evaporates, after which it is released into the atmosphere. This process has significantly lower water withdrawals compared to once-through cooling. Water is able to absorb a large amount of thermal energy when undergoing a phase change from liquid to vapor, therefore a larger amount of thermal energy can be extracted from the power plant per unit mass of water extracted. This process does contribute to water consumption, however, since the cooling water is released into the atmosphere and is unrecoverable by the immediate environment. Cooling tower systems can use either saline or freshwater. The use of saline water, however, slightly degrades the performance

of the cooling tower and can contribute to particulate emissions due to salts and other dissolved solids in the water being carried with the evaporated water [51].

- **Cooling Pond:** This system takes in water in a similar manner to cooling towers. Instead of evaporating the cooling water, however, it is discharged to a self-contained pond which cools the heated water by slow evaporation and heat transfer to the atmosphere. These systems consume lower amounts of water compared to cooling towers since not all of the intake water is evaporated and much of it is re-used. These systems, however, are only effective where large areas of land are available for the pond. The surface area of the pond affects the rate at which the water can be cooled.
- **Dry-Cooling:** This refers to a system that uses ambient air to cool the working fluid. Large blowers channel high flow rates of ambient air through liquid-vapor heat exchangers, and thermal energy is transferred directly from the working fluid to the ambient air. These systems use essentially no water, except that required for cleaning. Dry-cooling systems require significantly larger heat exchangers to transfer the same amount of thermal energy compared to any of the three systems previously described since the heat capacity of air is significantly lower than that of water. Additionally, ambient air is subject to larger temperature variations compared to bodies of water, which affects the minimum temperature that the steam-turbine cycle can reach. As described previously, a lower minimum temperature in a thermal power plant cycle contributes to higher efficiencies for a fixed maximum temperature. This applies to both steam-turbine and gas-turbine based cycles, but only the former is discussed here. Maximum cycle temperatures are typically fixed by design. With wet-cooling methods, the minimum

temperature of the cycle can be close to that of the water temperature which is generally low. With dry-cooling, however, the minimum temperature of the cycle must be slightly above the ambient air temperature, which can vary considerably and is generally higher than that of water bodies in the same area. Therefore, dry-cooling can decrease the efficiency of steam-turbine and combined-cycle thermal power plants.

In California, implementation of Section 316b of the Federal Clean Water Act by the State Water Resources Board includes measures to remove once-through cooling systems from power plants in the state. Approximately 19 power plants totaling 17.5 GW are affected by this regulation as of 2010. All of these units are expected to be in compliance with these measures by different times, with the latest date being December 31, 2029 [52]. The use of any of the alternative methods by replacements for these power plants will significantly decrease water withdrawals for the state. This is beneficial for protecting aquatic ecosystems and wildlife.

With the exception of dry-cooling, however, the use of alternative cooling systems may lead to increases in water consumption. For example, an average nuclear power plant in the U.S. using a cooling tower system consumes 2.5 times as much water as the same unit using once-through cooling [53]. However, this increase is small compared to the reduction in water withdrawal by removing once-through cooling.

Water Usage of Renewable Power Resources

Different renewable resource types have a different water consumption rate and care must be taken to consider the water withdrawal and consumption of these resources compared to balancing power plants. An overview of the water usage of different renewable resource types is presented here.

- **Wind power plants** consume the lowest amount of water in operation of all of the renewable resource types. Wind turbines harness kinetic energy in flowing air masses and convert it to electric energy. This process requires no water, and therefore wind power plants do not typically consume any water [51].
- **Solar photovoltaic power plants** also consume very low amounts of water in operation. These power plants convert electromagnetic radiation into electric power, a process which does not require water. For these power plants to be effective, however, the panels must be cleaned regularly to prevent the buildup of dust and other particles that may block sunlight. Depending on the location of the power plant, these systems consume anywhere from a negligible amount of water to as high as 33 gal/MWh [51].
- **Solar thermal power plants**, however, can consume large amounts of water in operation. Since these power plants are essentially steam-turbine thermal plants with a solar-based heat input, these units must be cooled in the same manner. Additionally, the major solar thermal resources in California are located in the southeastern desert area of the state, far away from coastlines. Therefore, cooling water will have to be provided from freshwater resources. These units, however, have a similar set of options for cooling methods as conventional steam-turbine thermal plants and can utilize those which only require low water withdrawals or consumption levels. Dry cooling in particular may introduce an issue for efficiency, however, due to the very high ambient air temperatures of the southeastern desert. Additionally, water must be used to clean the solar concentrators. Depending on the cooling system utilized, solar thermal power plants can consume as little as 26 gal/MWh for tower-based solar concentrator units with dry-

cooling to as much as 1,000 gal/MWh for Fresnel-lens based solar concentrator units with the use of cooling towers [51].

- **Geothermal power plants** can also consume large amounts of water in operation. These power plants are essentially steam-turbine thermal power plants with a geothermal heat input and have the same cooling options. Similar to solar thermal power plants, however, geothermal resources are concentrated in areas which may not be able to use salt water for cooling and will be likely to rely on the freshwater supply. In addition to cooling, geothermal plants can also consume water due to losses in the extraction and re-injection of water or geothermal fluid into the hot rock formation. Depending on the method of extraction and cooling method, these systems can consume as little as no water for cycles with a completely sealed working fluid (flash) [54] and dry-cooling to as much as 4,784 gal/MWh for hot-dry rock systems using cooling towers [51].
- **Biopower plants** can consume moderate amounts of water. Biomass and biogas fuels can be used in steam-turbine and gas-turbine thermal plants. Solid fuels used in steam-turbine power plants have the same cooling method options as solar thermal and geothermal power plants. Biogas used in gas-turbine power plants does not require water in operation. Depending on cooling method, these systems can consume as low as 35 gal/MWh for dry-cooled biogas systems to as much as 553 gal/MWh for steam-turbine systems using cooling towers in operation [51]. However, the water consumption of biopower depends strongly on the feedstock and how the feedstock was obtained, as certain types of biomass may require extensive processing before use, and some of these steps can consume water.

These water consumption factors are compared with those for conventional power plants based on a review by NREL [51] as summarized in Table 3. This comparison is for consumption in operation only, as water withdrawal in excess of consumption is assumed to be small due to the proposed elimination of once-through cooling. Therefore, figures for once-through cooling are not included if they constitute a bound of the range. Additionally, natural gas used in a simple gas-turbine thermal plant is not included since these units do not require water. The range presented here is that between the average water consumption of the least and most water intensive technology for particular power plant types.

Table 3 - Water Consumption Range of Different Electric Power Generation Resources

<u>Resource Type</u>	<u>Water Consumption Range (gal/MWh)</u>
<u>Renewable</u>	
Wind	0-1
Solar PV	0-33
Solar Thermal	26-1,000
Geothermal	0-4,784
Biopower (Operation Only)	35-553
<u>Non-Renewable</u>	
Coal	42-942
Natural Gas (Steam-Turbine)	340-826
Natural Gas (Combined Cycle)	2-378
Nuclear	610-672

2.1.1.1.2. Power Delivery

Power plants have not traditionally been located at or near population centers where electric energy is consumed. Since traditional economies of scale have preferred the construction of large power plants which people have found intrusive, these power plants are mostly located away from population centers. Therefore, power produced at centralized power plants are connected to an extensive power delivery system to move electric power to locations where it is needed.

The power delivery system consists of two components: the **transmission system** and the **distribution system**. Electric power produced at power plants first flows through the transmission system and then through the distribution system before reaching a consumer. Each of these components has limitations on their operation and how effective they can be at delivering power to load centers. A basic description of these components, their operation, and their limitations is presented in this section.

2.1.1.1.2.1. Transmission System – Structure and Basics

The transmission system is responsible for the movement of electric power over long distances from large centralized power plants to the load centers such as cities. It consists of a meshed network of high voltage conducting lines that span large distances across state lines, with multiple pathways available for power to move from one point to another. In the U.S., the transmission system is divided into two regions:

- **Western Interconnection.** This region spans from Canada in the north to the Baja California in the south and from the Pacific Ocean on the west to the eastern border of Colorado. This region is managed by the Western Electricity Coordinating Council (WECC).
- **Eastern Interconnection.** This region spans the remainder of the U.S. and Canada with the exception of Alaska, Texas, and Quebec, which each have their own interconnection.

Power does not typically flow between interconnection regions. Within an interconnection region, however, power plant and load centers are connected to each other by a network which spans the entire region. For example, power plants in Arizona provide power to Los Angeles, California. Power flow between different areas within an interconnection region is managed by

agreements between entities called balancing authorities. Balancing authorities are the operators of the transmission system. These entities will be described later in this section.

Transmission lines accept power from power plants at high voltages. Electric power is first produced at a power plant at low voltage and then stepped up in voltage by use of a transformer before being injected into the transmission system. Typical transmission line voltages range from 115 kV to 500 kV. The transmission system utilizes high voltages because the movement of electricity over large distances is more efficient at these voltages. The conductors which compose a transmission line have a very small resistance to electricity flow per unit length, but the total resistance of a line can be large since transmission lines are typically many miles long. This resistance causes some of the electricity that passes through the line to be lost by conversion to heat. The amount of power lost is determined by the magnitude of the electric current passing through the line. With high voltages, however, the same amount of power can be passed through a line at a lower current and therefore with reduced losses.

The transmission system also utilizes the alternating current (AC) form of electric power to move power instead of direct current (DC). This form was chosen because changing the voltage at the ends of a line is simpler when working with AC. The use of AC, however, means that controlling the power flow throughout the network requires additional considerations compared to the use of DC.

Electric power flow is achieved by voltage differences between connected points. With the AC form of electric power, voltage is not characterized by just a scalar as it is with DC electric power. AC voltage varies in time with a sinusoidal pattern. The voltage difference between points in an AC system is characterized by two traits:

1. The difference in the magnitude of the voltage sine wave
2. The lead or lag of the voltage wave in time at one point relative to that at another. This is characterized by the 'angle' between the voltages.

This can be represented graphically with vectors as presented in Figure 27:

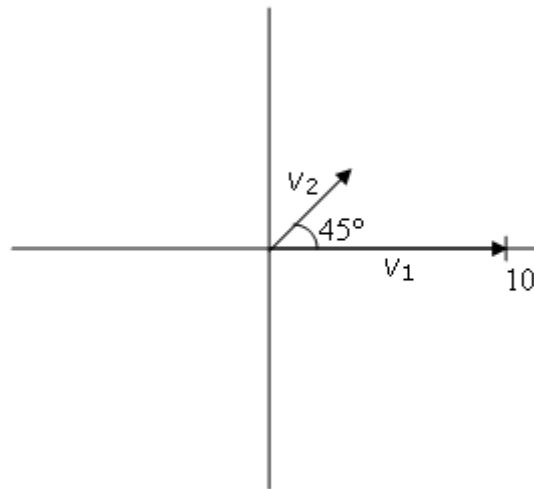


Figure 27 - Vector Representation of AC Voltages

The magnitude is the length of the vectors and the lead or lag is represented by the angle between them. The horizontal component of each vector is related to the resistance of the line and the load being served. The vertical component of each vector is related to the inductance or capacitance of the line and the load being served. At the endpoint of a line or a load, the voltage is typically fixed. At the sending end of a line, the voltage is managed such that subtracting the voltage drop across the line results in the fixed receiving end voltage.

AC electric power is also characterized by two components: real power and reactive power. The real power component represents useful power that is transferred across the line. The reactive power is power that flows back and forth through the line that is required to allow real power to

flow in AC systems. Both real and reactive power components occupy capacity in a transmission line, however. Reactive power is not a part of the useful power delivered across the line: it cannot be used to do work, but is important for voltage management. The flow of both real and reactive power contributes to line losses and voltage drops. The voltage drop due to real power flow is due to the resistance of the line and that due to reactive power flow is due to the reactance of the line. The higher the resistance or reactance, the higher the voltage drop due to a given amount of real or reactive power flow, respectively.

The ratio of real power to the total power flowing in a line is called the power factor. The power factor is a number between zero and one, and is a measure of how much useful power is being delivered compared to the total power flowing in the line. A low power factor indicates that most of the power in the line is reactive and not useful and vice versa for high power factors. High power factors are desirable because reactive power contributes to losses, but does not deliver a useful product. In many circumstances, however, it is beneficial to artificially increase or decrease reactive power flow in a line to manage voltages.

System operators employ a variety of techniques to manage voltages at each point in the network and power flow between those points to ensure that the required useful power is delivered to end uses without compromising the reliability of the system.

It is important to note that when generators inject electric power onto the transmission system, the path of power produced by a specific generator is not kept track of or directed. Rather, electric power from a power plant is aggregated with that produced by other power plants on the system. The transmission operator is responsible for managing the bulk power flow to ensure that all loads are met. Part of meeting this responsibility requires voltage to be managed such

that the power flow between points on the transmission system does not exceed line capacities or cause other stability issues.

2.1.1.1.2.2. Transmission System – Line Capacities

The lines which compose the transmission system have physical limits on how much power can be transferred through them. These power transfer limits are determined by a number of factors:

1. **Thermal Limits.** If too much current flows through a transmission line, the resistive losses will cause the line to overheat. This can physically damage the line with moderate overheating to reduce or its ability to transfer power, and sever the line at severe overheating which eliminates its power transfer capability completely. If this happens within a network, the loss of a major transmission path can destabilize the flow of power in adjacent lines. Additionally, even if the line itself does not melt, heating of the line causes material expansion which lets the line sag between posts. This may cause it to come into contact with trees or other objects at lower heights and cause fires. This is typically the absolute limiting factor for power transfer capability in a transmission line. The power flow level at which this becomes an issue is called the thermal rating. Thermal limits are typically the major issue for transmission lines less than 50 miles in length.
2. **Voltage Stability Limits.** As more current flows through a transmission line, the voltage drop along the line will increase. When too much current flows through a transmission line, it may undergo voltage collapse. In this case, the magnitude of the voltage at the receiving end will drop to very low levels and the power transfer capability of the line will decrease significantly. This will disturb the rest of the network. A typical effect is cascading power outages in unprotected areas. The loss of a transmission path may cause

parallel adjacent paths to be required to flow more power to meet the local demand, possibly causing those lines to undergo voltage collapse. Voltage collapse typically occurs at power flows significantly less than the thermal rating, and is typically more of an issue for transmission lines between 50 and 150 miles in length.

3. **Surge Impedance Loading Limits.** As discussed previously, AC voltage has a magnitude and angle component. If the difference in voltage angles between two points on the transmission line becomes too large in an attempt to flow too much power, the line can be susceptible to destabilization during a transient disturbance. In steady-state operation, the maximum voltage angle difference between two points is 90° . If a transient disturbance such as a fault occurs and the angle difference is allowed to go above 90° between two connected points, this can destabilize the system. Therefore, the maximum voltage angle difference between two points on a transmission line is limited to less than 30° in practice. This is such that if a transient disturbance occurs, there is sufficient margin in the angle difference to prevent destabilization. This is typically the major issue for transmission lines that are more than 150 miles in length.

System operators must manage the voltage between different nodes on the transmission network to prevent the capacity of any transmission line in the network from being exceeded. There are also other stability considerations which are not related to transmission line capacity that are not discussed here.

2.1.1.1.2.3. Transmission System - Grid Frequency

Grid frequency is the measure of how well the electric power system is balanced. The exact frequency target is set by the standards of the organization that manages the interconnection region. In the U.S., all interconnection regions utilize a frequency of 60 Hz, whereas in Europe a

frequency of 50 Hz is used. All power plants that connect to the system must output AC electricity at this specified frequency, and all loads that draw power from the system must be able to accept AC electricity at this frequency. These power plants and entities are said to be **synchronized** with the grid.

In steady operation, the electric power that is extracted from a generator is equal to the mechanical power input to the generator from a turbine, for example. The speed of the electric generator is fixed such that it produces electricity at the specified grid frequency under these conditions.

When there is an imbalance between load and generation, however, the speed of the electric generator may not be maintained. If the load demand is greater than the power output of the power plant, the power input to the electric generator will be lower than the power extracted. This will cause the generator to slow down and the generator frequency will drop. On the other hand, if the load demand is lower than the power output of the power plant, the generator will speed up and the frequency will rise.

On the transmission system, the frequency of the system is only allowed to deviate by a very small amount from the specified set point. In the event of a frequency deviation, the balancing authority sends an Automated Generator Control (AGC) signal to increase or decrease the power output of relevant power plants to restore the specified frequency.

The National Electric Reliability Council (NERC) sets standards for all balancing authorities in the U.S. for maintaining frequency limits within certain bounds. Balancing authorities typically employ a variety of measures to maintain the grid frequency during a system disturbance.

2.1.1.1.2.4. Distribution System – Structure and Basics

The transmission system is responsible for moving electric power from generators to the vicinity of load centers. Once power is delivered to a load center, the distribution system is responsible for delivering it to the different consumer loads. Distribution systems are typically operated by utilities, which sell electric power to the consumers. More details on load-serving entities will be discussed in a later section.

The transmission and distribution systems are connected at a substation. A substation is a facility that takes in high voltage electric power from the transmission system and steps down its voltage before passing it onto the distribution circuits that serve customers. Voltage is decreased before distribution for two reasons:

1. It is dangerous for very high voltages to be present in lines that people are close to.
2. Since the distance over which power is moved is substantially smaller than that in the transmission system, line losses are not as severe of an issue although they are still important.

The voltage of a typical line exiting a substation is between 12-66 kV. This voltage is still too high for consumer use, but it represents a balance between discharge concerns and line losses. The voltage is decreased in voltage further as the lines become closer to consumer connection points. A typical line voltage entering a neighborhood is about 480 V, and entering a house is about 120/240 V. Distribution systems still use the AC form of electric power.

2.1.1.1.2.5. Distribution System - Power Flow and Voltage Management

The distribution system is not as tightly networked as the transmission system. Distribution systems have traditionally used a radial configuration, where a central substation distributes

power to individual circuits that are not typically connected to each other. On each circuit, electric power typically has only one main line on which it can flow. If there were to be a fault on that line, it can cause outages or other issues. This is in contrast to the transmission system where there are multiple paths through which power can flow between points. This property renders the distribution system to be more susceptible to disruptions of service due to contingency events compared to the transmission system.

Circuits in the distribution system are designed with certain assumptions for the direction and magnitude of power flow. Using these assumptions, auxiliary equipment is placed and operated such that the voltage at each point on the circuit is within specified tolerances and acceptable for end-use. Essentially all equipment that uses electric power is designed to accept a particular voltage. Utilizing electricity at a voltage that deviates too far from that set point can damage equipment and devices or cause them to operate in unintended ways. To prevent this, equipment is installed to ensure that as the load on the circuit grows, these voltages can be maintained.

Voltage management is carried out using a number of strategies involving passive measures such as installing capacitor banks or active measures such as using power electronics. Maintaining desired voltages is not only important for managing power flow, but also for serving loads.

These systems are also typically oversized upon construction to account for projected load growth over the lifetime of the equipment.

As stated earlier, AC voltages are characterized by a magnitude and an angle. Serving different types of loads have different effects on the voltage:

- A **resistive load** is one that absorbs only real power. A resistive load has a power factor of 1 and only reduces the horizontal component of the voltage vector. Examples include toasters or incandescent light bulbs.
- An **inductive load** is one that absorbs only reactive power. An inductive load introduces a negative vertical component to the voltage vector and tends to reduce the voltage magnitude. Examples include electric motors.
- A **capacitive load** is one that produces reactive power. A capacitive load introduces a positive vertical component to the voltage vectors and tends to increase the voltage magnitude. Examples include power supplies for electronics.
- An **electric generator** produces real power and act to increase the horizontal component of the voltage vector.

Loads on the distribution circuits include all of these types, with the majority being inductive or resistive. Utilities employ power electronics, capacitor banks, or utilize certain inverters to manage the voltage at points along the distribution circuit in response to the effects of different load types. It is also important to note that loads can arise due to the properties of the lines themselves. For example, a long metallic transmission or distribution line often acts as an inductive load. Utilities must set their sending voltages such that the total voltage drop including effects of the line and the load being served will result in the desired voltage at the load. This is also the case in the transmission grid.

For example, consider a distribution circuit that is serving an industrial customer that uses many large electric motors. This load would cause the voltage deviate from the desired level on that

circuit. To counter this, a utility would raise the voltage at the substation or at a point near the load by installing a capacitor bank to restore the desired voltage level.

As another example, consider a distribution circuit that serves a data center at the end of the line with many electronic systems in operation. This may cause the voltage at the end of the circuit to rise, causing the voltage to deviate from the desired level. If the deviation is high enough, power may flow backwards into the substation. Utilities must then increase the substation voltage or introduce an inductive element to counter the capacitive effect.

2.1.1.1.2.6. Distribution System - Distributed Generation

The typical layout of the electric power system places power plants in remote, central locations.

In the modern electric power system, this is not always the case. Some consumers are opting to install power plants on their homes or buildings in the form of small gas turbines or solar photovoltaic panels. This is called **distributed generation**.

As stated earlier, generators produce real power and increase the voltage at a point on a circuit. Therefore, a distribution circuit with large capacities of distributed generation may exhibit a large voltage increase at points near the location of the generators.

Ideally, distributed generators produce power that is consumed by local loads. In this case, the substation only witnesses a small voltage rise at the end of the circuit since the power required from the substation is decreased. If there is insufficient load nearby to the generators to keep the voltage down, however, the voltage may rise significantly and power may flow back into the substation and onto the transmission grid. Certain connection equipment must be installed at the substation to allow this reverse power flow to be possible and accepted by the utility.

Additionally, transmission grid operators must be able to manage this reverse power flow within

reliability constraints of the system. Circuits with distributed generation must be managed to ensure that the power is delivered to where it is needed and the service voltage is maintained at all points in the circuit.

2.1.1.1.2.7. Distribution System - Harmonics

Ideally, the AC voltage follows a sinusoidal pattern with time at a frequency equal to that set by the transmission grid. Certain types of loads, however, can affect the voltage in such a way that distorts the sinusoidal voltage pattern. These distortions are called **harmonics**. Harmonics are caused switching loads that do not transition smoothly between different electric load points. Examples include electronics and fluorescent lights.

Electric equipment is designed to take in a sinusoidal voltage waveform. Distortions in the voltage pattern that such equipment uses can cause devices to behave in unintended ways. Examples include flickering lights or unintended tripping of circuit breakers. Additional effects include the generation of heat which decreases line capacities and a reduced power factor. Harmonics are typically countered or removed by employing power electronics, which are devices that inject power with patterns that neutralize the distortions and restore the sinusoidal voltage pattern.

2.1.1.1.3. Load Demand

The load demand component is where electric power is consumed and used to drive various commercial, residential, and industrial needs. Electric power is essential to the functioning and growth of every major industry in developed and developing countries. The magnitudes and patterns of the load demand dictate how the rest of the electric power system must behave. Every device or piece of equipment that uses electric power adds to the load demand, and their

operation determines its pattern in time. This section aims to give a high-level overview of the different types of loads that compose the load demand and their patterns.

2.1.1.1.3.1. Load Demand Sectors

Electric energy usage patterns are products of user preference. An example of the aggregate load profile for a week in California is presented in Figure 28:

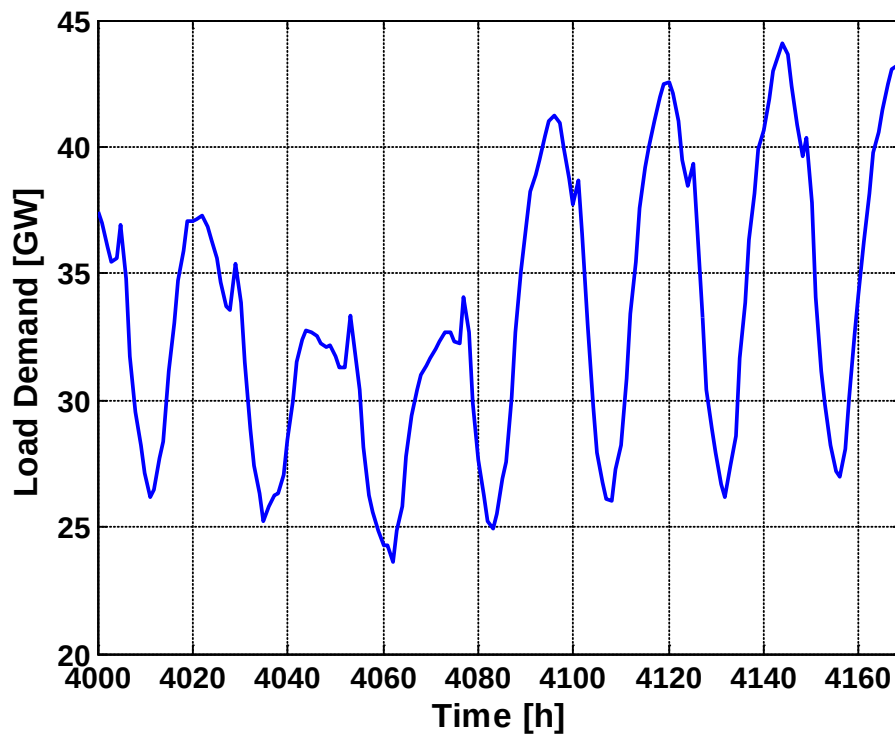


Figure 28 - Example 1-week Load Demand for California from CAISO data for 2005

Electric energy usage is typically categorized into three sectors. Throughout the day, the load profiles of these different sectors behave quite differently.

The **commercial** sector includes all electric loads that are associated with commerce and business operations. This includes but is not limited to the electric energy usage of small and large office buildings, restaurants, shopping malls, retail stores, universities, etc. The aggregate commercial load is composed of a variety of individual loads: small loads such as lighting and

electronics to large loads such as air conditioning for large buildings and refrigeration. The commercial load is generally low in during the early morning hours, rises to high during the daytime through the early evening hours, and drops off to low levels by the late evening. The majority of commercial establishments are not open for business in the early morning or late night hours. Certain businesses open or close later than others, leading to a relatively gradual decrease throughout the evening hours.

The **residential** sector includes all electric loads associated with dwellings. This includes but is not limited to the electric energy usage of houses, apartments, condominiums, and any other establishment where people may live. The aggregate residential load is composed of many small individual loads such as lights, computers, appliances, etc. The residential load is generally low during the late night and early morning hours as the majority of people are asleep. During the morning hours, the residential load rises to a high level as people wake and operate devices in their house before going to work. From the late morning to the late afternoon hours, the residential load is low as most people are out of the house at work or school. The residential load rises to its highest peak in the early evening hours as people return from work and wind down, before the load drops to low levels as people go to sleep.

The **industrial** sector includes all electric loads associated with industrial processes. This includes but is not limited to the electric energy usage of factories and processing plants. The industrial load is composed of a diverse set of processes, but typically consists of a relatively small number of very large loads. The industrial load as a whole has a relatively constant profile. Factories and processing plants typically have equipment and processes that continuously and all day.

Additionally, certain loads that are a part of multiple sectors also stand out as having a relatively predictable pattern. Cooling and air handling loads are typically highest during the day when temperatures are high, and lighting loads are typically highest during the nighttime or early morning when there is little daylight. Trends in the load demand also occur on seasonal timeframes. The total load demand tends to be at its highest during the summer due to air conditioning loads, and lighting loads tend to be at their lowest due to the presence of more daytime hours.

In California, 38.5 percent of the total electricity use is due to the residential sector, 35.4 percent due to the commercial sector and 25.8 percent due to the industrial sector. The remaining fraction was used for electric vehicle charging in the transportation sector, which has not traditionally been a significant part of the electric load [49]. These three categories are used by utilities to assign a rate structure type to a customer.

The combined behavior of the load demand sectors results in an aggregate, state-wide load profile that is typically at its highest during the daytime hours through the late afternoon, slightly lower during the early-mid evening hours, and low elsewhere. The load profile of any given region – city, county or the like – will depend on the composition of its customers. A community that consists mainly of businesses will follow the commercial load more strongly, for example. The composition of the load demand throughout the day and throughout the year will depend on region as well.

2.1.1.1.3.1. Peak Hours and Time-of-Use Pricing

The hours of the day when the load is typically at its highest levels are called peak hours. During these hours, the generation and power delivery components of the electric power system are under the most stress. Many power plants are online, producing large amounts of electric power

that is taking up capacity in transmission and distribution lines, making management of power flow more difficult. Hours immediately before and after these periods are called near-peak or semi-peak hours, and all other hours are called off-peak hours.

The daily and seasonal behavior of the load demand leads utilities to set electric energy prices for the consumer to different levels throughout the day and throughout the year. Electric rates tend to be at their highest during peak hours of the day when the grid is highly stressed. This practice occurs because utilities must purchase electric energy from power plants in the electricity market. This is typically done on a least-cost first basis, where electric energy from power plants offering the lowest prices to that utility is purchased first, then the next most expensive, and so on until the load demand served by that utility is met. The details of the process which gives rise to this trend will be discussed in Section 2.1.1.4. The more electric energy that a utility has to purchase in order to satisfy a high load demand; the more expensive it becomes to do so per unit of electric energy. This additional cost to the utility is reflected in increased electric rates to the consumer. This practice is also carried out due to seasonal variations in the load demand: electric energy rates tend to be higher in the summer and lowest during the winter. The period of the day that is considered to be peak hours varies from utility to utility.

2.1.1.2. Major Entities in the Electric Power System

The electric power system is a complex piece of infrastructure. The system requires precise control of many operating parameters while coordinating the actions of many parties – power plant owners, load serving entities and transmission/distribution system operators. To function adequately and robustly, a number of major entities which are each responsible for managing different aspects of the system coordinate their actions to ensure electricity service for customers. An introductory description of some of these major entities is presented here.

It is important to note, however, that some of these entities are not mutually exclusive in all areas. For example, a balancing authority can also be a load serving entity which is the case in some areas. An area which does not employ a market-based mechanism for selling and buying electric power may not have scheduling coordinators. The entities described here are mutually exclusive for California, however.

2.1.1.2.1. The North American Electric Reliability Council (NERC)

The North American Electric Reliability Council or NERC is the organization that is responsible for the establishment of operating standards that are common to all balancing authorities. It is a non-profit organization formed in 1968 for the purpose of ensuring the reliability of the electric power system.

The responsibilities of NERC include but are not limited to:

- **Establishing reliability and planning standards** for owners and operators of the electric power system. These standards are proposed by the NERC standards committee which is composed of representatives from different major entity types in the electricity sector. These standards must be approved by the Federal Energy Regulatory Commission (FERC). If approved, these standards become legally binding to all owners and operators of the electric power system.
- **Enforcing compliance with established standards.** This is carried out through monitoring, audits, and investigations. An entity which violates NERC standards can be subject to financial or legal penalties. NERC monitors the parameters of the electric power system that are relevant to established standards in real time.

- **Conduct reliability and adequacy assessments.** This is to identify any areas of concern in the electric power system regarding balancing and robustness. NERC does not, however, have the authority to introduce standards aimed at addressing the identified issues.
- **Event analysis.** In the event of a large scale outage, NERC performs investigations to identify their causes and provide a report on ‘lessons learned’.
- **Gathering information about infrastructure security threats.** NERC monitors and gathers information on security-related incidents and potential issues, and communicates them to government authorities.
- **Certifying power system operators.** NERC is responsible for certifying organizations such as balancing authorities before they are allowed to operate their respective part of the power system. Entities participating in the electric power system must be certified by NERC.

2.1.1.2.2. Balancing Authorities

A balancing authority is the organization that is responsible for ensuring that a control area is balanced. A control area refers to a given geographic region. This entails ensuring that the load demand within their control area is satisfied with the appropriate amount of generation such that the system frequency matches that set by the standards of their interconnection region. Carrying out this task typically requires that it fulfills some basic roles:

- **Securing sufficient generation resources ahead of time to meet the predicted load demand.** This involves using the means to create a relatively accurate prediction of the time-resolved load demand for future dates, typically the next day. The balancing

authority must also create a means for power plant owners to transfer electric power to load serving entities. This can be accomplished by the creation of an electric market for power plants of different capacities to list their prices and for load serving entities to purchase power from different plants to meet the load demand of their respective territories. The balancing authority is also responsible for moderating transactions in this market to ensure economic fairness for all parties involved. More on the electric market will be discussed in Section 2.1.1.4. Alternatively, non-market means may be used where the balancing authority simply sets prices based on public agreement. Additionally, the balancing authorities coordinate the importing and exporting of electric power between their respective balancing areas.

- **Operate the transmission system.** The balancing authority is in charge of the major transmission corridors that span its control area. Balancing authorities control and direct power flow from power plants to substations. It must ensure that the power purchased by utilities is delivered in the requested amounts and at the appropriate times. To incentivize power flow paths that are easier to manage, the balancing authority may introduce a congestion charge on top of the price of electricity offered by a power plant if it is to be delivered to a utility through a congested line.
- **Ensure the reliability of the transmission system.** To comply with interconnection standards, the balancing authority must put measures into place that enable the transmission system in its territory to remain balanced even if a major generator or transmission line fails. This type of event is known as an “N-1” contingency. The

balancing authority also continually monitors the voltages and frequencies at points in the system to prevent system disturbances.

In California, the major balancing authority is the California Independent System Operator (CAISO) and the corresponding balancing area encompasses the entire state of California with the exception of a few isolated areas. Balancing authorities are regulated by their relevant interconnection region managing entity (WECC for CAISO) and the Federal Energy Regulatory Commission (FERC).

2.1.1.2.3. Scheduling Coordinators

In areas where the balancing authority employs a market for selling and buying electric energy and system services, individual utilities and power plants cannot typically participate in it directly. To participate, power plants and utilities are represented by entities known as scheduling coordinators. Scheduling coordinators are primarily responsible for placing bids to buy or sell electric power within the market. These bids represent the interests of the parties that they represent.

While the balancing authority sets up and moderates the electricity market, the scheduling coordinators are the entities that actually operate it. Scheduling coordinators have a number of responsibilities including but not limited to:

- Submitting and assuming responsibility for bids to buy and/or sell electricity.
- Tracking and settling power trades between the entities that it represents and between itself and other scheduling coordinators.
- Providing the amount of ancillary services capacity required by the balancing authority.

- Ensuring that any of its bids does not violate environmental regulations.

To become a scheduling coordinator in California, an organization must be certified by CAISO.

2.1.1.2.4. Load-Serving Entities and Utilities

A **load-serving entity** is an organization that is in charge of operating the distribution systems within a given balancing area. A load-serving entity that owns transmission and distribution lines and operates the latter is called a **utility**. While the balancing authority operates the transmission system, utilities own transmission lines in their territory and are responsible for building and planning adequate transmission capacity in their territory. Currently, utilities purchase electric energy from power plants in the electricity market and sell such energy to consumers to meet the load demand for their territory. Utilities can also own and operate their own power plants to supplement or displace the energy that they purchase. The electric utility is responsible for ensuring the reliability of the distribution system and the quality of electric service to individual customers.

Utilities can be structured in different ways. A short description of the major types of utilities is presented here.

Investor-Owned Utilities (IOUs)

An investor owned utility is a for-profit organization that sells electric energy to consumers as a private corporation. These organizations are funded by shareholders who have invested money in the company. The company aims to garner profit for these shareholders, who also typically elect the management of the company. In California, IOUs tend to be very large organizations and provide electricity service to approximately 68 percent of consumers.

In California, the practices of an investor owned utility are regulated by the California Public Utilities Commission (CPUC). The CPUC regulates investor-owned utility services including electric, natural gas, telecommunications, water, railroad, rail transit, and passenger transportation companies to ensure safe, reliable utility service and infrastructure at reasonable rates for California consumers. For electric utilities in particular, the CPUC fulfills roles including but limited to:

- Approving the electric rates and electric rate structures proposed by IOUs. This is aimed at preventing artificial inflation of electric rates to consumers while maintaining a reasonable profit margin for the IOUs.
- Setting standards for power system reliability, inspection and maintenance of power system infrastructure equipment and safety practices. This is aimed at ensuring the quality and safety of electric service to consumers.
- Setting environmental standards for the permitting and construction of power system infrastructure equipment. This includes the siting of transmission and distribution lines.
- All investor-owned utilities must comply with CPUC standards to conduct business in the state of California.

Publicly-Owned Utilities (POUs)

A publicly owned utility is a non-for-profit organization that sells electric energy to consumers as a public service. These organizations are funded by the governments of the cities or territories that they serve. The organization aims to optimize benefits for local customers such as low

electricity rates and the growth of local businesses for example. POU's are typically managed by a locally elected board that hires public employees.

The practices of a POU are regulated by local officials or city councils. This includes but is not limited to:

- Approval of electric rates and rate structures. This attempts to resolve issues of competing interests at the local level.
- Setting standards for maintenance and reliability of power system infrastructure equipment.
- Approving investments and construction of transmission and distribution lines.
- Determining the resource mix for power procurement.

The practices of a POU are not regulated by the CPUC. These utilities are still required to comply with rules set by CAISO to participate in the electricity market.

In California, POU's tend to be relatively small organizations. Collectively, POU's provide electric service to about 24 percent of consumers.

Other Load-Serving Entities

The remaining 8 percent of consumers in California are served by organizations that are not structured in any of the manners described previously. Some of these other organization types are as follows:

An **Electric Service Provider (ESP)** is a non-utility entity that provides electric service to customers within the territory of an IOU. ESPs are typically small organizations which aim to serve a particular type of load while using the distribution infrastructure of an IOU. All ESPs are required to register with the CPUC. ESPs work with scheduling coordinators to procure electricity from the market.

A **Community Aggregator** is a local government that purchases electricity for its end-use customers and does not own distribution facilities or transmission facilities.

2.1.1.2.5. Power Plant Owners

Power plant owners are the entities which own generation resources and sell electricity on the market for purchase by load serving entities. Power plants can be sorted into two primary categories by ownership:

1. **Utility-Owned Power Producer.** A utility-owned power producer is a power plant that is owned and operated by a load serving entity. Although utilities own these resources, they must bid into the electricity market to sell electric energy and services if these units are not under contract. A utility (through a scheduling coordinator) can make bids to both buy electric energy and services from power plants not owned by them and sell electricity from their own generation. Utilities are not allowed to withhold generation resources exclusively for serving their own territory. For example, a utility which owns a combined cycle power plant cannot produce electric energy for only customers of that utility exclusively. In California, utility owned power plants produce 42 percent of the electricity supply.

2. **Independent Power Producer.** An independent power producer is a power plant that is not owned or operated by a utility. These plants can be owned by corporations or cooperatives. The owning entities exclusively sell energy and services on the electricity market which is then purchased by load serving entities. In California, independently-owned power plants produce 58 percent of the electricity supply.

2.1.1.3. Reliability Requirements

Electric power is central to the operations of every industry. In order to ensure that electric service is readily available at all times, the electric power system is designed and operated with a number of reliability measures.

In the electric power system, generation is scheduled and procured ahead of time to meet the predicted load demand within environmental and transmission capacity constraints. The load prediction, however, is not entirely accurate to the extent required for maintaining a balanced system. The actual load demand may be higher or lower or occur at different times than predicted depending on usage trends and other parameters such as weather. Additionally, contingency events such as a loss of a major transmission line or power plant can disturb the system balance. To enable the electric power system to continue operating in the face of these uncertainties, the balancing authority requires generation capacity to be available for measures called ancillary services. Ancillary services are that which ensures reliability and supports the transmission of electricity from generation to load. The nature of the major reliability measures are discussed here.

2.1.1.3.1. Reserve Capacities

A major component of ancillary services is the presence of reserve capacity. Reserve capacity refers to power plant capacity that is available for responding to differences between actual and predicted load and to contingencies that affect the balancing of the system. These services are provided and purchased in the electricity market. For CAISO, this refers to three different types:

- **Frequency Regulation.** This refers to generation capacity which is used to compensate for differences between the actual load and forecasted load and maintain grid frequency within specified stability limits. These power plants operate to minimize the ACE (Area Control Error) of a given balancing area by acting to keep the generation and load balanced on a second-to-second basis. The Area Control Error is a combined metric that measures the deviation of actual load from forecasted load and the deviation of actual grid frequency from that set by the standard for that region. The power plants which provide this service are already online and providing power to meet the forecasted load demand (energy market), but are also receptive to automatic controls that respond to an AGC (automatic generator control) signal from CAISO which alters their power output on a second-to-second basis to balance the system and maintain frequency when necessary. Under current standards, power plants providing regulation services must be synchronized, able to receive and respond to AGC signals, and deliver the full committed power in less than 10 minutes based on its ramp rate [44, 55].
- **Spinning Reserve.** This refers to additional capacity in power plants that can provide useful energy when required to compensate for a contingency event such as an unexpected loss of generation, transmission corridor or a large, unpredicted variation in load. Typically, power plants providing this service are also already online and

synchronized, and will operate at slight part-load conditions (for example, 90 percent) and leave the remaining capacity available for responding to a contingency condition. These power plants are typically the first generation resources to respond to a contingency event since they are already operating. Under current standards, power plants providing spinning reserve services must be synchronized, be able to contribute the full committed power within less than 10 minutes from the onset of the contingency condition, and be able to maintain the committed power for at least 2 hours [44, 55].

- **Non-Spinning Reserve.** This refers to capacity in power plants that are not already operating that can provide useful energy when required to compensate for a contingency event such as an unexpected loss of generation or transmission corridor. These generators are offline until called upon to provide the committed power. Under current standards, generators providing non-spinning reserve services must be able to provide the full committed power within less than 10 minutes from the onset of the contingency condition and be able to maintain the committed power for at least 2 hours [44, 56].

2.1.1.3.2. Frequency Regulation

NERC sets standards for balancing authorities to maintain the frequency within their territory to be within a certain range of the scheduled frequency of 60 Hz. This range is encompassed by the Area Control Error (ACE) discussed in the description of the regulation reserve capacity. The allowable minute-averaged ACE over a 12-month rolling period is calculated separately for each interconnection region. Additionally, the influence of frequency deviation on the ACE varies by balancing authority. More details can be found in the NERC Standard BAL-001-0.1a [57].

Large deviations in grid frequency from the set point can cause power outages, electric generators to trip offline due to protective measures and equipment damage. Additionally, the

timing of automated systems that depend on the grid frequency for time-stamping will need to be recalibrated, a potentially costly task [58].

In practice, the grid frequency is maintained within very tight bounds. For a representative example, consider deviation from the set point of 60 Hz. Governors will need to respond if the frequency drops below 59.98 Hz or rises above 60.02 Hz for time correction. Power outages will start to occur at about 59.1 Hz. Generators will shut down if the frequency drops below 58.5 Hz or rises above 61.5 Hz. Further deviation will damage equipment. This is shown schematically in Figure 29:

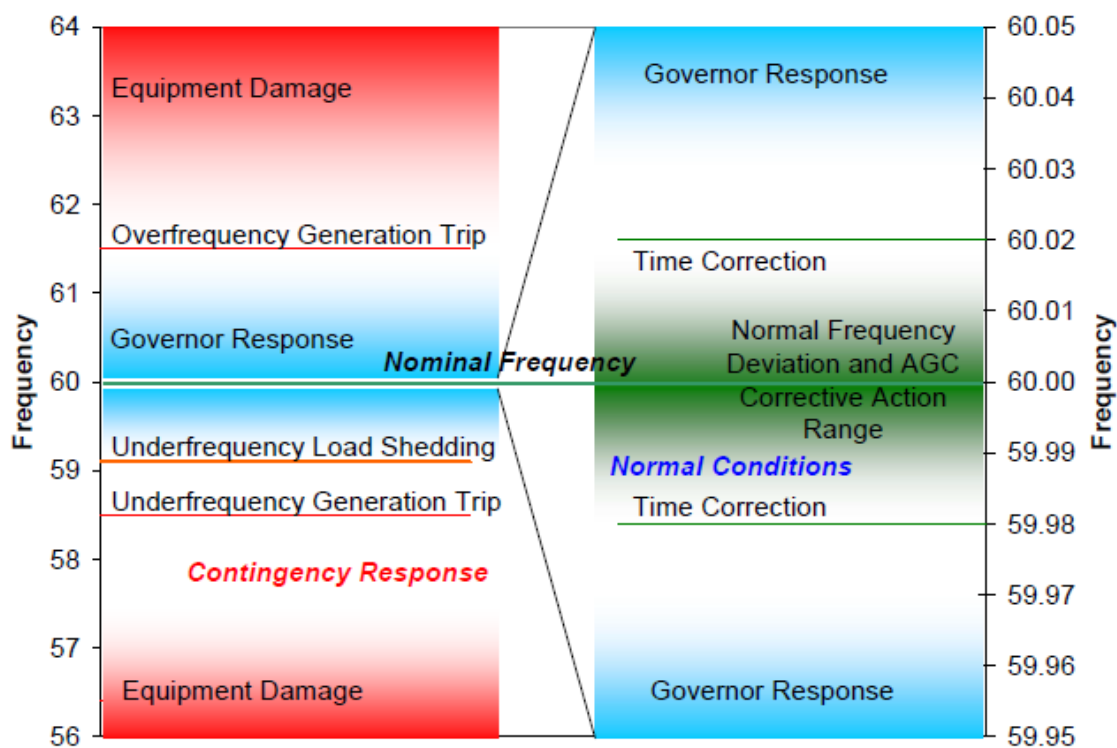


Figure 29 - Grid Frequency Deviation Effects [59]

Contingency events have the potential to severely disrupt the grid frequency. While small deviations in frequency are handled with regulation capacity, large deviations require more

extensive measures. The loss of a major generation resource due to an unexpected shutdown in a power plant or the failing of a major transmission line can prevent electric power from being delivered to satisfy the load demand. This causes the system to become unbalanced, causing the grid frequency to drop.

To prevent this from occurring, measures are implemented specifically to restore the grid frequency after a contingency event. Frequency-based contingency events are primarily an issue on the transmission system.

A typical sequence of post-contingency events and the effect of frequency response measures are displayed in Figure 30 [59]:

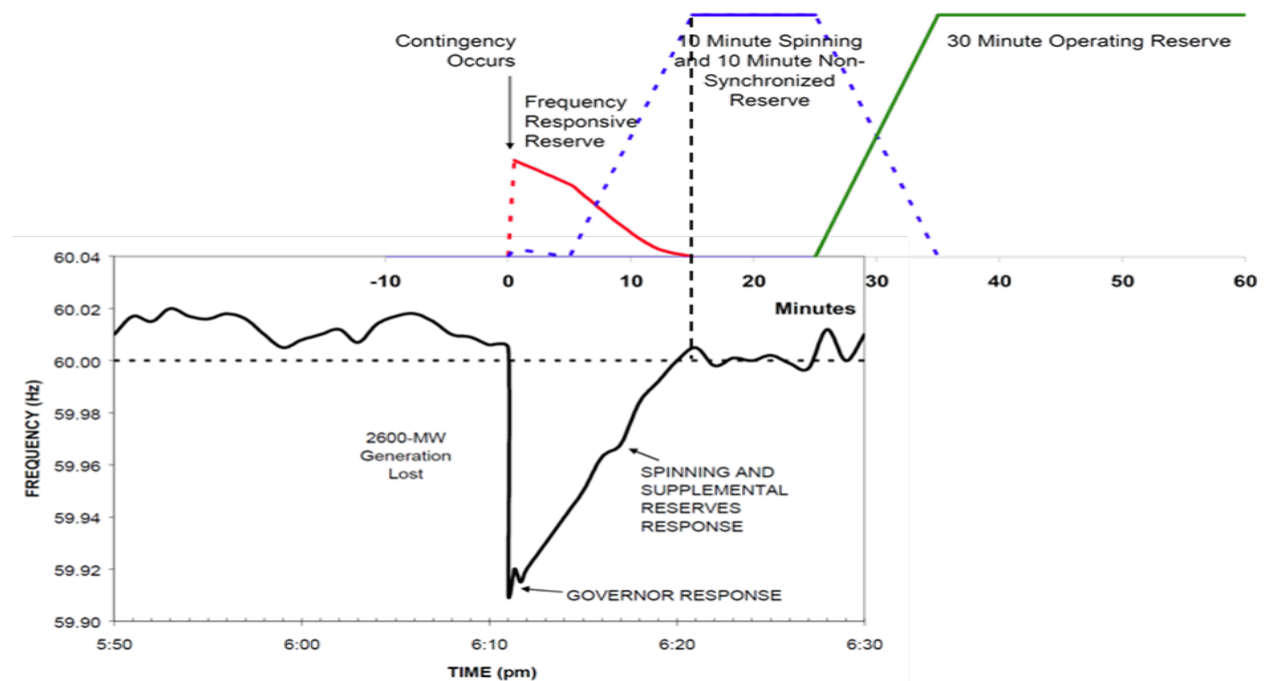


Figure 30 - Frequency Restoration after a Contingency Event [59]

Immediately after the loss of generation, the grid frequency drops. The first effect to dampen the extent to which it drops before reliability measures can respond is system inertia. This aspect will be discussed in more detail in Section 2.1.1.3.4. The response of reliability measures is as follows:

1. **Governor response.** A governor is a device which controls the speed of an electric generator. This is the first measure to respond, typically within 8 seconds of the contingency event. As soon as a drop in frequency is detected, governors temporarily increase the electric power output from a generator.
2. **Spinning Reserve response.** This is the second measure to respond. Power plants that provide spinning reserve services as described prior are called upon by the balancing authority to utilize that capacity to provide additional generation. The full capacity committed to spinning reserve services must be provided within 10 minutes of the contingency event, although many plants reach this point sooner. As these resources increase their power output, the governors return the extraction of electric power to normal levels.
3. **Non-Spinning Reserve response.** This measure responds in parallel with spinning reserve, but typically occurs later due to the time required to start the power plant. Power plants that were originally offline but committed to provide non-spinning reserve services are called to be online and operating at the committed capacity within 10 minutes.
4. **Replacement Reserve response.** This is the final measure to respond, and is aimed at restoring the spinning and non-spinning reserve capacity of the system. Power plants which were originally offline are brought online such that the power plants providing

spinning and non-spinning reserve capacity can return to normal operation. This restores the ability of the system to handle another contingency event. This is sometimes referred to as 30-minute or 60-minute operating reserve.

These measures restore the grid frequency to its target set point and return the system to normal operation.

2.1.1.3.3. Voltage Regulation

The need to manage voltages on the grid to ensure that produced power reaches load centers where it is needed is necessary on both the transmission and distribution systems. Balancing authorities and load serving entities have access to a range of measures to maintain stable voltage profiles on transmission and distribution lines, respectively.

On the transmission system, voltage profiles that lead to too much power flowing down one line will cause voltage collapse and therefore a contingency event. Additionally, other contingency events such as the failure of a transmission line can contribute to voltage collapse and cascading outages. On the distribution system, undesirable voltage profiles can damage user equipment or operate such in unintended ways or cause power to unexpectedly flow into the substation.

NERC standards specify that balancing authorities and utilities maintain and operate sufficient voltage management resources to protect voltage levels during normal operation and contingencies. More details can be found in the NERC Standard VAR-001-2 [57]. The allowable voltage deviation ranges for different base voltage levels are established by the ANSI C84.1 standard. This standard also defines two different allowable deviation ranges for normal and emergency operation. Additionally, standards for service and utilization voltage are defined separately. The standard summarized as follows:

- Voltages between 120 V and 600 V:
 - Normal: 95-105 percent for service, 90-104.2 percent for utilization.
 - Emergency: 91.7-105.8 percent for service, 86.7-105.8 percent for utilization.
- Voltages greater than 600V:
 - Normal: 97.5-105 percent for service, 95-105.8 percent for utilization.
 - Emergency: 90-105 percent for service, 86.7-105.8 percent for utilization.

Voltage regulation is achieved by managing reactive power flow. AC electric power generators produce both real and reactive power, and both components contribute to a voltage drop. On the transmission system, balancing authorities can require generators to change their reactive power input or activate/de-activate capacitive or inductive resources connected to transmission lines.

This is referred to as **voltage support**. On the distribution system, reactive power can be managed by controlling distributed generation, inverters or other types of power electronics.

In California, CAISO has developed operating procedures for voltage control and limits on voltage deviation on the transmission system that participating entities must comply with.

Details on these procedures can be found in the CAISO operating procedure for voltage and VAR control [60].

2.1.1.3.4. System Inertia

System inertia in the context of an electric power system refers to the ability of the electric power system to resist changes in the grid frequency during an imbalance in load and generation.

This property is tied to the physical inertia of the spinning mass in power plants and electric generators. If the load is greater than the generation, the speed of the electric generators will

slow down and vice versa if the load is less than the generation. This causes decreases and increases in frequency, respectively.

Typically, these electric generators receive their power input from a rotating turbine in a power plant. Thermal and hydroelectric power plants, which currently form the majority of the generation capacity, are composed of multiple, heavy rotating parts interacting with each other. These rotating parts have physical inertia which prevents them from slowing down or speeding up too quickly when energy is injected in or extracted from them. This acts to prevent the electric generator from slowing down too quickly when the load demand exceeds the generation on the grid, and vice versa when the load demand is less than the generation. The electric power system consists of thousands of power plants, each with their own inertia. The combined inertia of all of the power plants is what gives the power system the ability to delay changes in grid frequency during an imbalance.

Not all power plants have a high degree of inertia, however. For example, solar photovoltaic plants have no spinning mass, and therefore do not contribute to the inertia of the system. Therefore, a distinction is made between inertial and non-inertial generation. The latter does not have any physical inertia to contribute to the inertia of the system.

In discussing frequency response measures, it was noted that the factor which limited the drop in frequency immediately after a contingency event before any of the measures could respond was the system inertia. This property is important for fulfilling that function. Consider a period where the inertia is too low due to not enough inertial generation being online at a given time. A loss of a major generator may cause the frequency to drop much farther before frequency

response measures could react, causing the problems discussed earlier. This can amplify the damage and cost of recovering from the same contingency event.

System inertia is also important for determining the allowable level of import power that a balancing authority can procure. Since import power contributes to the balancing of load and generation within a balancing area, it can affect the grid frequency within that area. If system inertia is low, variations in the import power will cause larger variations in the grid frequency for that area. Furthermore, a sudden loss in import power due to a contingency in the exporting area may cause the frequency in the importing area to drop too far before response measures can act if the inertia of the importing area is too low. Therefore, a power system in a given balancing area must have high inertia in order to reliably use a large amount of import power from another balancing area.

2.1.1.4. The Power Procurement Process

The goal of the electric power system is to deliver reliable electric service to customers. To achieve this, it must not only be technically sound but also economically sound for all parties involved. The entities who own power plants need revenue from selling electric power to recover and profit from their investment. Utilities require revenue to construct and maintain transmission and distribution systems. Balancing authorities, while non-for-profit, require revenue to operate and monitor the transmission system reliably. At the same time, load serving entities and customers who purchase electric energy and services are only willing or able to pay so much for these commodities. The power procurement process attempts to reconcile all of these needs.

The vast majority of territory in California is controlled by CAISO, which uses an electricity market to meet the economic needs of power plant owners, utilities, and customers. The electricity market is a means for suppliers to sell electric energy and services and load serving entities to buy such commodities. A **supplier** in this case refers to either a power plant or group of power plants represented by a scheduling coordinator. This market operates under what is called **economic dispatch**. Economic dispatch is defined as “the operation of generation facilities to reliably serve customers, recognizing any operating limits of generation and transmission facilities”. The electric market employed by CAISO aims to provide electric service to customers at the lowest cost possible given the power plant mix of the territory. An overview of the electricity market mechanisms employed by CAISO will be discussed here. These mechanisms are current as of July 2012 and may be revised or modified in the future, but give a good general understanding for how the market operates such that how it needs to be changed to accommodate renewables can be understood.

It is important to note, however, that there are many ways by which the major entities in the electric power system can choose to meet those needs. These methods are not always based on an electricity market. For example, the Bonneville Power Administration (BPA) which has some territory in northern California is a balancing authority which is also a load serving entity and does not use an electricity market. BPA owns the vast majority of generation that it procures and sells electricity directly to customers in its territory at a given rate as a public service. Additionally, there are other dispatch mechanisms such as flat or stressed dispatch which cause the major entities in the power system to interact in different ways to provide electric service.

2.1.1.4.1. Types of Products Traded in the Electricity Market

Two main types of products are sold and bought by different entities participating in the electric market:

- **Bulk Energy.** This refers to the electric power required to meet the load demand over a given time interval (i.e. hourly). Suppliers can submit bids to sell bulk energy into the market and load serving entities can submit bids to buy bulk energy to meet their demand. The amount of energy sought to be sold and bought depends on the forecasted demand in the day-ahead market and on the instantaneous demand in the real-time market.
- **Capacity.** This refers to two different types:
 - o **Ancillary Services** such as regulation, spinning and non-spinning reserve as described previously. Suppliers submit bids to provide capacity for different services. CAISO organizes the bids in economic order and accepts bids starting with the cheapest bids first. The cost of procuring ancillary services is passed onto the load serving entities for the corresponding region.
 - o **Residual Unit Commitment.** This provides additional capacity that is needed to meet the load demand in the case that not enough supply is offered as bulk energy. Suppliers submit bids to perform this service. CAISO accepts bids in a similar manner to ancillary services.

CAISO uses these products to ensure that the load demand is met reliably and at the lowest cost possible by making power plant owners compete to sell their products and services. These products are traded in two different markets: the day-ahead market and the real-time market.

These markets and how buyers and suppliers bid into them are discussed in the following sections.

2.1.1.4.2. Bidding into the Electric Market, Pricing and Restrictions

Each type of product or service described has its own market. Within these markets, suppliers submit bids to sell the product or service. Buyers submit bids for buying those products and services. The basics of these processes are described here.

Suppliers and buyers of a product or service will submit a bid curve to the market. A bid curve indicates the price that a supplier or buyer is willing to sell or buy a commodity dependent on how much of it they are buying and selling. For example, if a power plant is selling power for a given hour (energy), it may charge \$120 per MW for power values between 0 and 100 MW, and \$140 per MW for power values above 100 MW up to its maximum power.

Suppliers submit increasing bid curves. They set a higher price per unit of commodity provided if they are requested to sell more of it. Buyers submit decreasing bid curves, where they set a lower price per unit of commodity bought if they request to buy more of it. The price where these bid curves meet is called the market clearing price. This represents an agreement between suppliers and buyers for the price of the product or service in that market. Suppliers agree to sell power at this price and buyers agree to buy power at this price, and the commodity amount corresponding to this point is what is transferred from supplier to buyer. At this point, the market is considered 'settled' or 'cleared'. An example for the energy market is demonstrated in Figure 31:

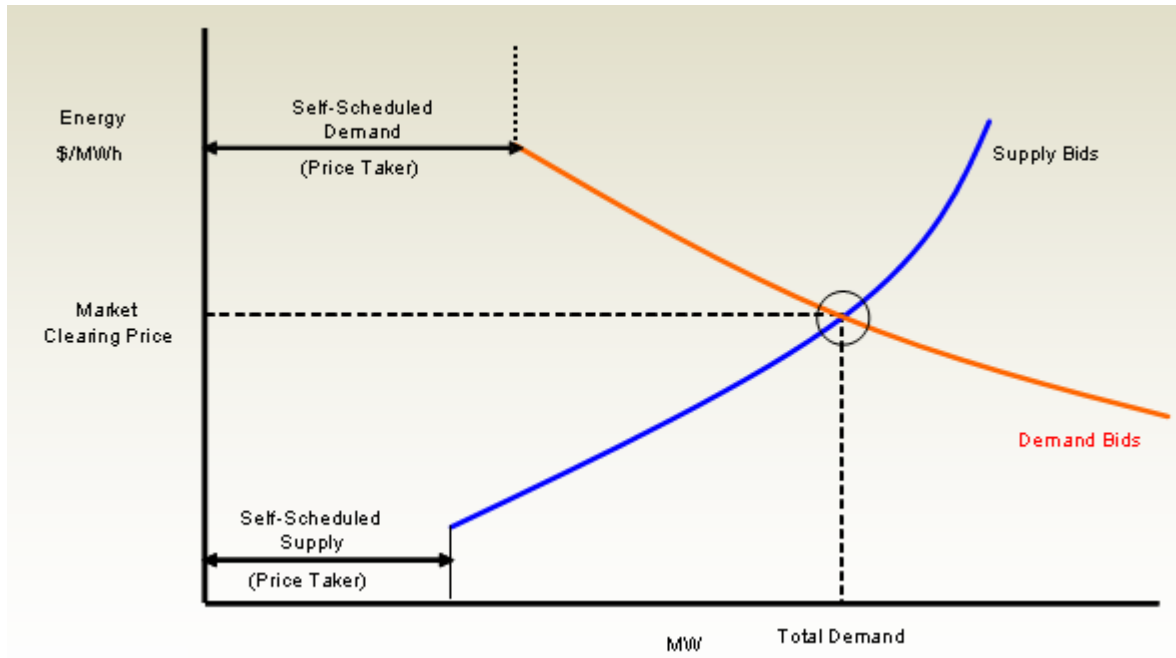


Figure 31 - Demand and Supply Bid Curves

The blue curve is the supplier bid curve and the orange is the demand bid curve. These curves are shifted by the effect of self-scheduled supply and self-scheduled demand.

In the market for each product or service type, there are many suppliers and buyers each submitting their own bid curves. These individual bid curves are stacked in economic order to determine the market clearing price for a product.

The price that suppliers are actually paid and buyers are actually charged is called the Locational Marginal Price (LMP). Suppliers are paid the LMP at the point where they inject power into the transmission system and buyers pay the LMP at the point where they extract power from the transmission system. This price is modified slightly from the market clearing price and depends on the location. The modifications are as follows:

- **Marginal Cost of Congestion:** This adds the cost associated with causing congestion problems in transmission lines due to injecting or extracting power at that point in the transmission system.
- **Marginal Cost of Losses:** This adds the cost associated with losses in transmission lines.

The LMP is equal to the market clearing price plus these modifications, and separate LMPs are computed for different products and services. In CAISO territory, the LMP is calculated at about 3,500 different spatial points in the system.

The bids submitted by suppliers are also subject to environmental constraints. The fulfillment of these bids if awarded must not violate the environmental regulations relevant to the location of the power plant.

2.1.1.4.3. Day-Ahead and Real-Time Markets

CAISO allows products and services to be traded in different markets that open and close at different times. These markets are geared towards different purposes. An overview of the purposes and processes of these markets are discussed here.

2.1.1.4.3.1. Day-Ahead Market

The day-ahead market is concerned with ensuring that there will be enough electric energy supply and reserve capacity to reliably meet the load demand for the next day. The use of a day-ahead market is aimed at allowing more competitive pricing for energy and ancillary services.

The timeline and major processes of the day-ahead market is as follows:

1. **Opening of the day-ahead market for submission of bids.** Bids for supply and demand of electricity are accepted starting from 7 days before the trading day. The **trading day** is the day when these products and services will actually be transferred and

used. Bids for the day-ahead market are not accepted after 10 am on the day before the trading day.

2. **Market Power Mitigation (MPM).** This process is aimed at ensuring that no supplier has the ability to artificially manipulate their prices due to their location. A supplier with this ability is said to have “market power”. For example, if a supplier knows that they will have to provide at least 200 MW of power over a given hour to meet local reliability requirements on the transmission system, they can submit a bid curve that significantly increases the price per increment of power at 200 MW. The MPM process prevents this from happening. During this process, CAISO reviews the bid curves and runs simulations of the transmission system to determine if a supplier has market power. If a supplier is identified as having market power, their bid curve is modified to mitigate their advantage before being considered in the market. This process produces a bid pool that is considered in the next process. Additionally, this process also designates Reliability Must-Run (RMR) units. These are units that are determined to be required to run for local reliability concerns.
3. **Integrated Forward Market (IFM).** This process is where the bids from suppliers and buyers interact to determine the market clearing price for each product within power plant and transmission limitations. The amount of energy that will be sold in the market is determined, and 100 percent of the ancillary services needs on the system are bought by CAISO. This process produces binding time schedules for energy and ancillary services provision for each supplier with an accepted bid and their corresponding prices. Additionally, CAISO notifies which power plants will be required to start up ahead of

time due to this process. CAISO covers the costs associated with starting up for these power plants.

4. **Residual Unit Commitment (RUC).** This process allows CAISO to procure additional capacity required to meet the load demand from generators submitting bids to sell available capacity. Capacity in this market is required when the amount of energy sold in the IFM is not sufficient to meet the forecasted demand for any point of the day. Suppliers with an accepted bid are required to produce a bid to sell energy in the real-time market and are paid during that market. Additionally, suppliers that are under a resource adequacy contract with a load serving entity are automatically available to be used as RUC capacity. These suppliers bid into the market with a zero dollar price, since they have already been paid by the load serving entity for their services and must be available for CAISO use.

5. **Closing of the day-ahead market.** The market is closed and the prices are published.

2.1.1.4.3.2. Real-Time Market

The real-time market opens after the close of the day-ahead market. The real-time market is focused on keeping the system balanced in the face of load variations and managing real-time power flow. This is different from the day-ahead market which is more focused on ensuring that there is sufficient bulk energy to meet the demand of different load serving entities and that sufficient reserve capacity is available. Specifically, the real-time market is used for:

- Procuring energy to meet the instantaneous load demand.
- Reducing supply if the demand is lower than predicted. In this case, CAISO must pay suppliers to reduce output.

- Curtailing demand if there is insufficient generation.
- Obtaining more ancillary services as needed.

Therefore, the only buyer in the real-time market is CAISO since they are responsible for keeping the system balanced. Suppliers submit bids for each of the different products and services which CAISO awards them starting with the lowest cost bid and awards more bids as needed. Eligible suppliers in the real time market include power plants with capacity or energy that was not committed in the day-ahead market and loads that can be curtailed on demand. Bids can be submitted for either an increase or decrease in supply at a particular time, and CAISO awards these bids as needed.

The schedules for suppliers and buyers from the day-ahead market form the basis of the energy schedules in the real-time market. Additionally, bids submitted in the real time market are separate and distinct from those submitted in the day-ahead market. The processes for the real-time market are as follows:

1. **Opening of the Real-Time Market.** The real-time market opens at the close of the day-ahead market, and bids are accepted up to 75 minutes before the trade hour.
2. **Market Power Mitigation (MPM).** This process generally works in the same manner as in the day-ahead market. In this case, the process only looks at the next hour instead of the next day and produces a bid pool for the next process.
3. **Hour Ahead Scheduling Process (HASP).** This process occurs once every hour and evaluates bids for different products and services to propose a solution for balancing the system. CAISO then awards the bids for imports and exports that are part of the solution

in economic order. The result is a binding energy schedule for imports and exports and an advisory energy schedule for power plants for the next hour.

4. **Real-Time Unit Commitment (RTUC).** This process issues start up and shut down instructions for fast-start power plants as needed and occurs continually every 15 minutes. Additionally, more ancillary services are procured by CAISO as needed and suppliers are awarded accordingly.
5. **Real-Time Economic Dispatch (RTED).** This process dispatches available power plants with an energy bid to meet the very short-term load prediction, and occurs continually every 5 minutes. This is the main process that balances the instantaneous load demand. Suppliers are awarded accordingly.
6. **Close of the Real-Time Market for that hour.** Processes end for the trade hour and begin for the next trade hour.

In addition to these processes, CAISO also has other actions that it can take during the real-time market in case of a contingency or reliability concern. These additional actions are described as follows:

- **Contingency Dispatch.** In the event of a contingency, CAISO converts reserve capacity into energy to compensate. Reserve capacity can also be converted and used as balancing energy if there is not enough supply on the system.
- **Exceptional Dispatch.** There are two types of exceptional dispatch:
 - **Out of Sequence** dispatch is when a bid is taken out of economic order and awarded immediately to mitigate a transmission system constraint.

- o **Out of Market** dispatch is when CAISO uses capacity in a power plant that does not have a bid in the market.
- **Manual Dispatch.** This refers to system operators manually dictating the dispatch of power plants. It is used only in the event that the RTUC and RTED processes cannot produce working solutions and is only used as a last resort.

Overall, the day-ahead and real-time markets are mechanisms employed by CAISO to meet the needs of the major entities in the electric power system. These mechanisms aim to provide the lowest cost of reliable electricity by having suppliers compete for electricity sales within generator and transmission limits.

2.1.1.4.4. Extra-Market Agreements

The electric market exists to allow competition between power plants to sell power and produce a low price of electricity. In California, however, a significant portion of the energy that is used to meet the load demand is procured outside of the electric market. Load serving entities typically negotiate contracts to purchase power from specific power plants at agreed upon rates for a certain amount of time. These contracts can last up to a number of years and have their own daily schedules for providing and consuming electricity. These power plants and load serving entities do not bid into the market with a price, however, their schedules must be submitted to CAISO so that the physical energy flow on the transmission system can be monitored and taken into account.

These supply and demand schedules are called **self-schedules** since they refer to energy schedules that are self-imposed by the agreement between a load serving entity and a power plant. Self-scheduled supply and demand refers to supply and demand that has been procured

outside of the electric market. This shifts the bid curve since it refers to a commodity amount that is already procured. For example, a utility and a power plant group have a contract for 100 MW of power during a particular hour. This 100 MW of power does not need to be procured from the market. Therefore the bidding for supply starts above this power level. This influences the market by shifting the commodity level at which the bid curves start to higher values.

Extra-market agreements can also exist for extra capacity. The CPUC mandates that load serving entities have a certain percentage of their peak monthly demand procured as capacity as a margin of safety. Many of the power plants used in the RUC process fall into this category.

2.1.2. Transportation Vehicle and Infrastructure Constraints

The electric power system is a centrally-managed and precisely controlled system, operated in real-time by the coordinated efforts of a number of different entities. The operations of the light-duty transportation infrastructure with respect to sustainability, however, largely arises from the travel patterns of consumers and is shaped by their preferences. While regulatory entities and traffic authorities impose rules for vehicles and roadways, these entities do not operate the system and dictate its energy and water consumption levels in the same sense that corresponding entities operate the electric power system. Consumers who operate light-duty vehicles and use the roadway infrastructure each have their own needs which must be met. Therefore, constraints on this system are characterized more so by the behavior and usage patterns of the consumers and some of these aspects are discussed here.

2.1.2.1. Vehicle Travel Patterns

Light-duty transportation vehicles must be capable of meeting consumers' transportation needs. Therefore, to understand the advantages and disadvantages of transitioning the light-duty transportation paradigm towards the usage of alternative vehicles and the installation of their

respective infrastructures, the patterns of consumer travel demand must be understood. While active tracking of vehicles has not been conducted due to privacy issues, vehicle travel patterns can be characterized by two factors: the vehicle dwelling time distribution and the daily miles traveled distribution.

2.1.2.1.1. Breakdown of the Vehicle Dwelling Time

The vehicle dwelling time refers to the length of time that a vehicle is being driven to a given destination or present at that destination. A breakdown of the vehicle dwelling time allows one to track what vehicles are being used for and where they are typically located on a fleet-wide average basis. Based on data in the National Household Transportation Survey (NHTS), the distribution of the vehicle dwelling time for the average consumer is presented in Figure 32 [61]:

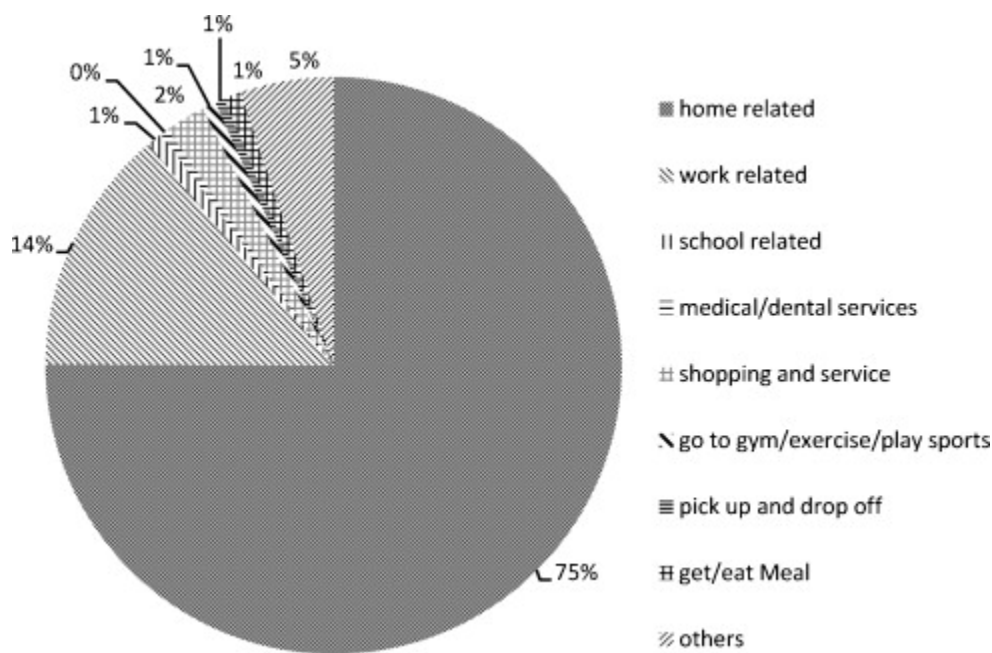


Figure 32 - Distribution of Light-Duty Vehicle Dwelling Time [61]

The vast majority of the time, light-duty vehicles are either at residences or being driven home. This is expected since the average consumer leaves the vehicle at home after arriving home from the workplace and during sleeping hours of the night. The second largest share of the vehicle

dwelling time is the workplace, which is also expected since the majorities of consumers drive to their place of employment and leave their vehicles there during the workday. These two locations take up 89% of the vehicle dwelling time, and imply that a constraint on the light duty transportation system is to allow consumers to reliably meet their need to travel to and from the workplace. This also implies that fueling infrastructure must be accessible for all consumers on the routes between residences and workplaces, or at these locations themselves, for these needs to be met reliably.

The remainder of the vehicle dwelling time is composed of miscellaneous activities as listed. While these activities have a smaller share of the vehicle dwelling time, this does not indicate that they are not important. Vehicle capabilities and the configuration of the refueling infrastructure must allow consumers to meet these needs in addition to home and workplace transportation needs. What this does signify, however, is that the accessibility of refueling infrastructure from these locations may not be as high of a priority as that for the home and workplace routes.

2.1.2.1.2. Breakdown of the Vehicle Trip Length

Consumers require that their vehicles be able to perform the trips that meet their needs. These trips are a diverse set, and span a range of distances. Vehicles which compose the light-duty transportation fleet must be able to accommodate these travel distances without significant inconvenience to their schedules. A plot of the cumulative distribution of the vehicle trip length for the average light-duty vehicle driver in the U.S. in 2009, using trips which start and end at the residences, is presented in Figure 33 [62]:

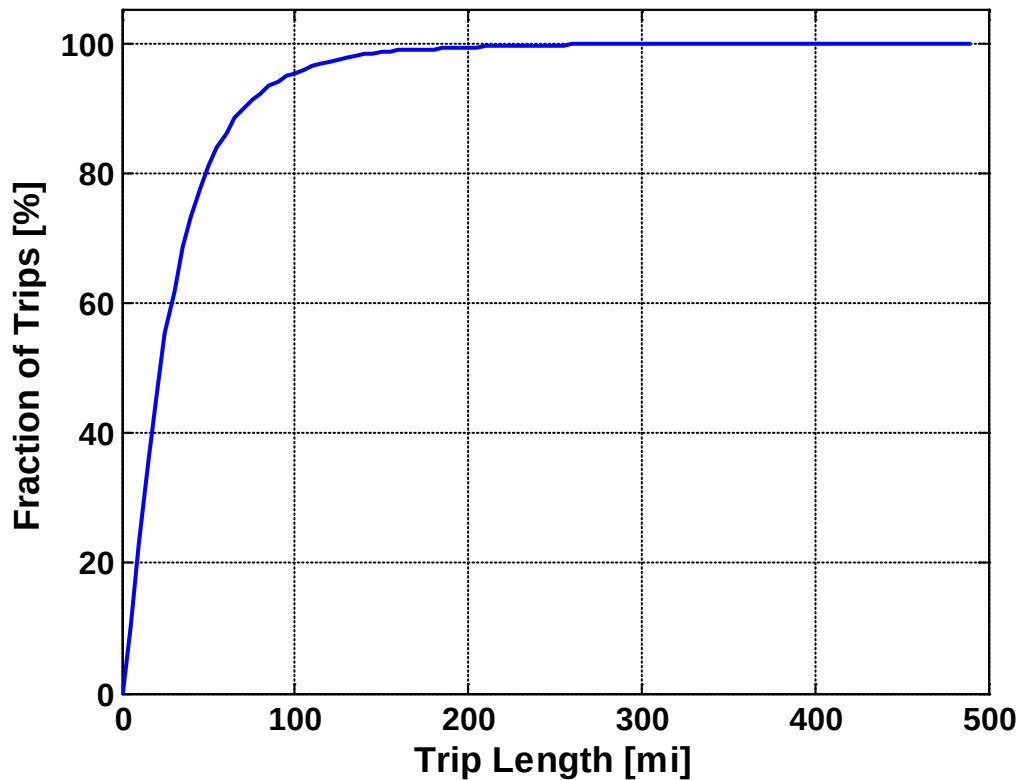


Figure 33 - Cumulative Distribution of Vehicle Trip Length for the Average U.S. Light-Duty Vehicle Consumer [62]

For trips that start and end at home, approximately 92% of the trips are less than 100 miles, and essentially all of the trips are less than 200 miles. The large majority of consumers – about 80% - suffice with trips that are less than 50 miles to meet their average transportation needs.

Therefore, vehicles must be able to perform these trips at a minimum to be considered as a suitable alternative to conventional gasoline vehicles in the light duty transportation fleet.

Additionally, many trips that consumers take do not necessarily start and end at their residences, and consumers may also make multiple trips to and from their residences. Vehicle alternatives which are not able to accommodate these other transportation needs will require consumers to change the manner in which they use their vehicles, which could potentially be a hurdle to implementation and consumer acceptance.

2.1.3. Water Supply Infrastructure

The water supply infrastructure requires the coordinated efforts of many different entities to function. Due to the nature of water supply and demand, however, the management of this infrastructure is not as centralized as the electric power system and does not operate on the same timescales. A high-level overview of the water supply infrastructure and demand trends is presented here.

2.1.3.1. Water Supply

2.1.3.1.1. Sources and Reservoirs

The most significant source for freshwater is **precipitation**. Rainfall due to weather patterns returns evaporated water vapor in the atmosphere to the ground. In the colder mountainous regions, precipitation takes the form of snowfall which builds up in the mountains. This collection of snow or “snowpack” melts during the warmer months of the year to provide freshwater. For California, precipitation in surrounding states contributes to freshwater supply through the Colorado River and many other channels from Oregon and Mexico that enter the state [8].

The water influx can be categorized by the type of reservoir it is collected in. These reservoirs are what the water infrastructure draws from to meet society’s water needs:

1. **Surface water.** This refers to water from precipitation which is collected in natural reservoirs such as lakes and rivers or in man-made reservoirs such as canals, dams, and aqueducts. Water is drawn directly from these reservoirs to feed end-uses. In California, the majority of the surface water originates in the northern and eastern mountain regions of the state in the form of the Sierra snowpack. The water content of this snowpack is higher than all of California’s lakes and man-made reservoirs combined [63].

2. **Groundwater.** This refers to water from precipitation that was not collected as runoff into lakes, rivers or man-made reservoirs. Rather, this water directly falls on land areas, infiltrates through the ground and collects in underground basins or aquifers.

The supply of freshwater from precipitation varies from year to year depending on weather patterns. During years of low precipitation, the demand for water exceeds the water supply and the amount of freshwater stored in surface and groundwater reservoirs is decreased. The opposite is true for years of high precipitation, where an abundance of supply recharges these reservoirs. If successive years of low precipitation relative to long-term water usage take place, this leads to a depletion of streams and groundwater reservoirs called **overdraft**.

The supply of freshwater to the state from year to year depends strictly on weather patterns. Precipitation can vary widely from year to year, dependent not only on rainfall and snowfall but also on that in surrounding areas that sustain major inflows to the state such as the Colorado River regarding California. During low precipitation (drought) years, dependence on water stored in these reservoirs is important to meet water usage needs.

The supply of water is considerably variable. Weather patterns change precipitation levels inside and outside of a given area from year to year, and the amount of freshwater influx that the state has to work with is currently unable to be strongly influenced by societal input. Certain strategies on the supply end such as desalination and cloud seeding are present, but are limited by practical factors and potential unintended weather alterations respectively. For example, the reservoir storage levels for the state of California for two different periods: a drought period between January 2008 and December 2009 in Figure 34 and a normal period between July 2011 and June 2012 in Figure 35 [64].

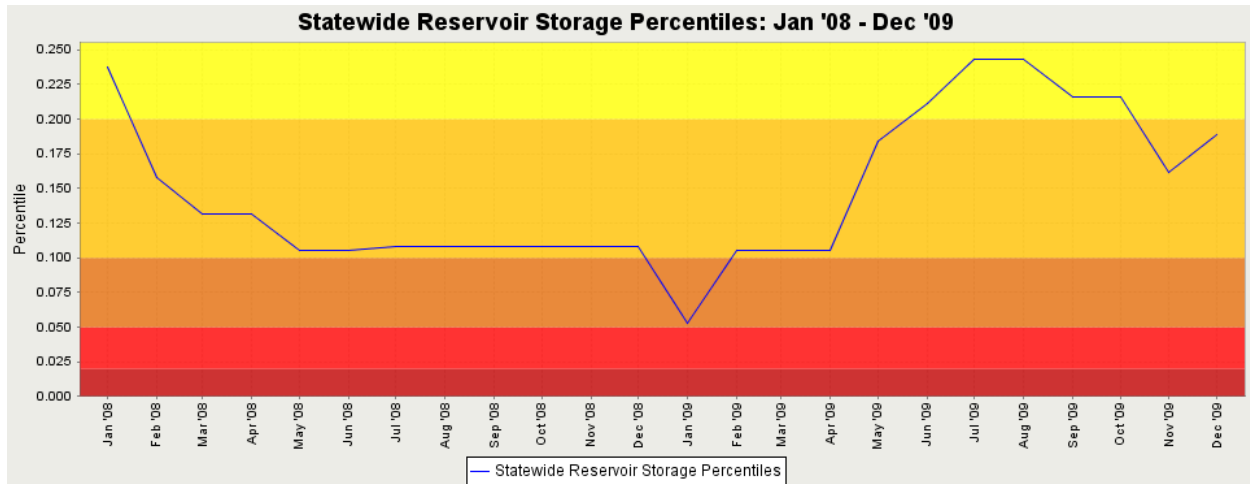


Figure 34 - CA Statewide Reservoir Levels, Jan. 2008 to Dec. 2009 [64]

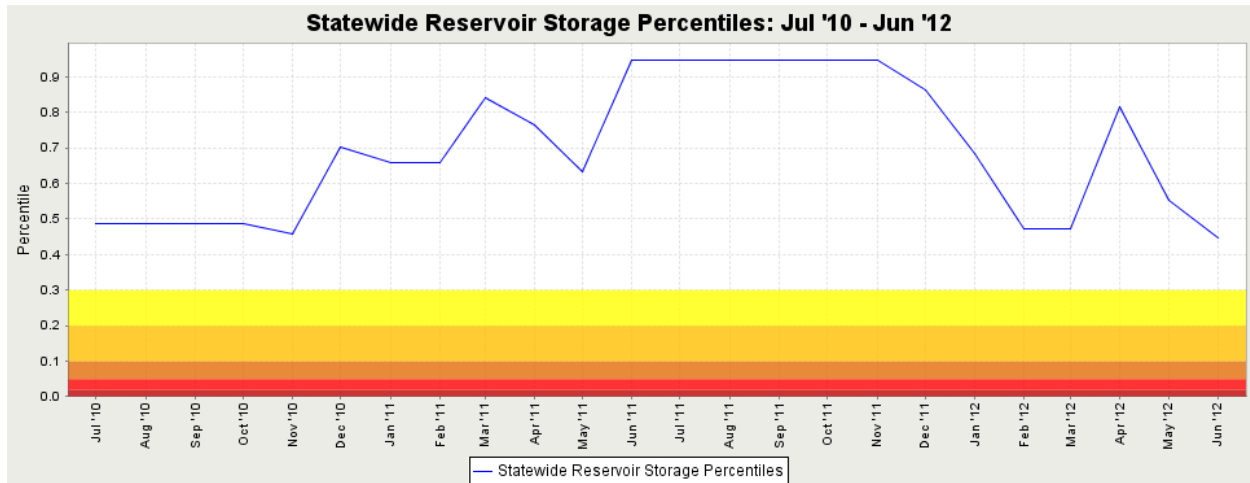


Figure 35 - CA Statewide Reservoir Levels, Jul. 2010 to Jun. 2012 [64]

The different colors indicate different levels of drought severity, with yellow indicating a moderately dry condition and dark red indicating a critically dry condition where statewide reservoirs are at extremely low levels. During the drought period, statewide water reservoir levels dropped to extremely low levels due to low precipitation levels over a long period of time. Only six months later, changing weather conditions brought normal precipitation levels and the statewide water reservoir levels were increased to stable levels. This showcases the strong variability of the available water supply not only from year to year, but between different

multiple-year periods. Additionally, the effect of climate change on weather patterns is also expected to affect the variability of precipitation available for use in the state.

Since water supply is inherently variable, management of water usage is a much more prevalent factor to maintain the balance between supply and demand. In the water supply sector, efforts are focused on matching demand to available supply through water conservation, improving water use efficiency, and maintaining adequate storage to tolerate supply variability. This is accomplished in California by the installation and management of a strongly interconnected reservoir network. The management of this network allows water to be available to customers even during periods of low precipitation up to an extent, and allows water availability to be extended from rainy/snowy seasons to the entire year. Additionally, this allows the delivery of water resources in the relatively wet northern part of the state to the arid southern part of the state, where much of the population resides. The layout of the network of reservoirs and canals in California is presented in Figure 36:

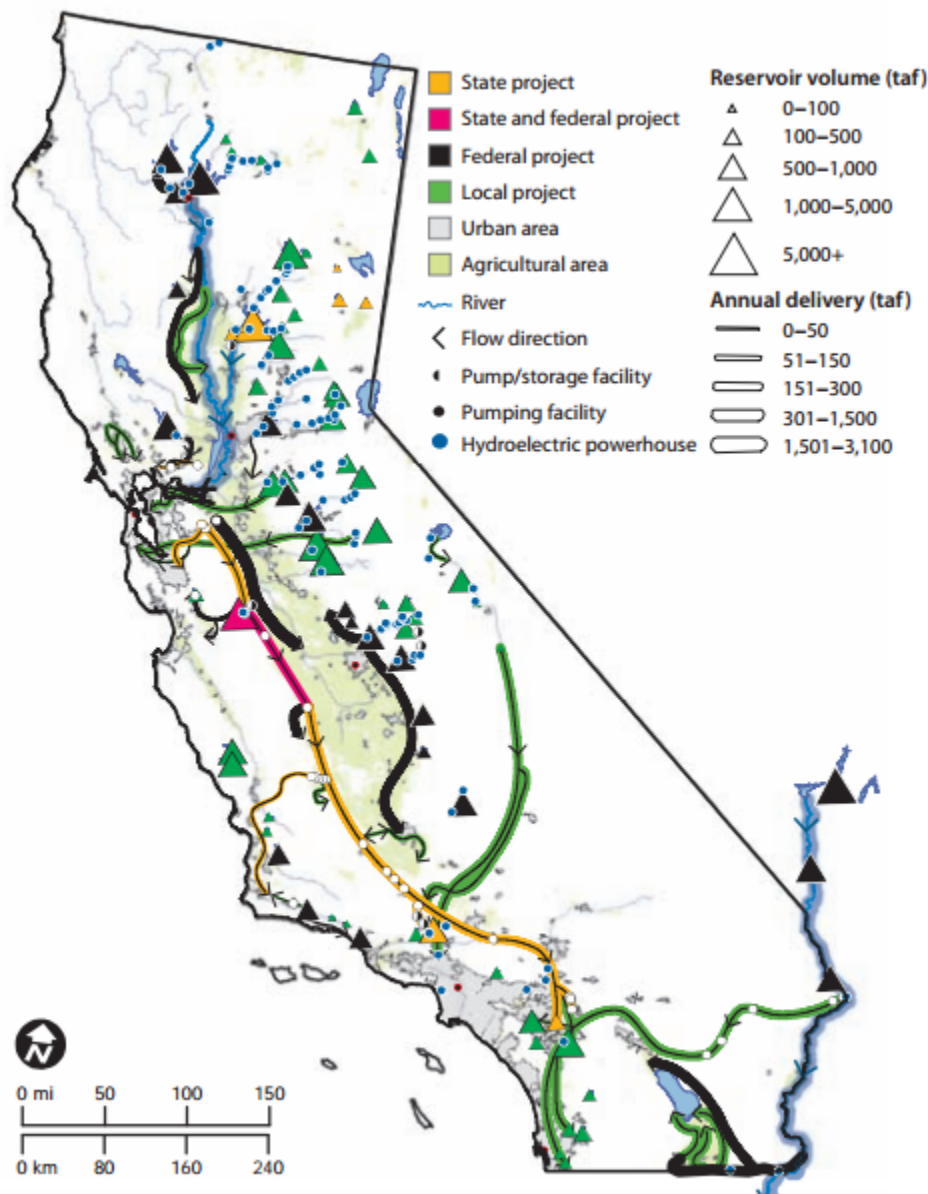


Figure 36 - Overview of California's Reservoir and Canal Network [9]

Different parts of this infrastructure are controlled by different agencies. Each local water utility in a given region is responsible for procuring and delivering water to consumers of any type which fall within their service territory. Procurement of water resources can be obtained from various sources, including but not limited to:

- **Local groundwater aquifers within the jurisdiction of the utility.** Many utilities have access to groundwater aquifers within their territory, however, they are also responsible for management of aquifer levels for long-term water resources planning.
- **Surface water reservoirs that are owned by a given water utility.** Many utilities buy the rights to certain natural surface reservoirs and construct local projects to convey water from it exclusively to their territory. An example includes the Los Angeles Department of Water and Power's use of the Owens Valley Reservoir.
- **Surface water deliveries from state projects.** In California, a large portion of the water resources is sourced from the Sacramento Delta, which collects inflow from all major rivers in the state with the exception of the Colorado River. State conveyance projects have been constructed to deliver water from the Delta to consumers, especially in the southern part of the state. Water utilities submit requests to the Department of Water Resources for delivery of a certain amount of water over a year, and these requests are accepted, partially accepted, or denied depending on the current and forecasted water supply conditions for that year. These deliveries are called **allocations**. Allocations are especially important for regions which do not have typically high precipitation or other local water resources.

Local water utilities and the Department of Water Resources must manage their respective components of the water supply system under the main constraint of **ensuring that sufficient water resources will be available to satisfy demand over short-term and long-term planning horizons.**

2.1.3.1.2. Overview of Electric Energy Requirements Due to Water Use Needs

Extensive management of water resources through the development of a reservoir system and reduction of water demand through efficiency improvements are necessary to meet the water needs of consumers. Managing water resources in this manner requires energy input.

For California in particular, the water sector as a whole comprises about 19 percent of the total electric load demand and about 30 percent of the non-power plant natural gas supply [8, 63].

This includes electricity and natural gas use of the water infrastructure itself *and* that of water-related end uses. The distinction must be made between the two contributions. Water related end-uses alone contribute to 13.95 percent of the total electric load demand, leaving a 5.05 percent contribution due to the water infrastructure. The water infrastructure includes components for water conveyance, treatment, distribution, and collection/treatment of wastewater. Water-related end uses include the various functions that water is used for in the residential, industrial, and commercial sectors. These will be described in detail in this section.

As the demand for water grows and water efficiency measures are implemented, the water supply sector can potentially have a significant impact on the electric load demand. This section will provide an overview of the energy intensity of water infrastructure processes and interactions between projected behaviors of the electricity, transportation, and water sectors.

2.1.3.1.2.1. Energy Requirements for Water Conveyance

Weather patterns are not uniform throughout California's geography. Precipitation is concentrated in particular areas, primarily the northern and eastern mountainous regions of the state. These areas also contain the majority of the natural reservoirs used for water storage. Additionally, river inflows are also located in the northern and eastern areas of the state.

The vast majority of urban freshwater demand is located on the coastal areas, however. Total urban freshwater use is concentrated in areas of high population such as the South Coast and San Francisco regions. These regions are located away from the areas where precipitation occurs, the location of natural reservoirs such as the Sierra snowpack, and the point of entry for river flows such as the Colorado River. Agricultural freshwater demand, while not located on coastal areas, is not necessarily adjacent to natural reservoirs or high-precipitation areas. Therefore, to meet the water needs of urban and agriculture consumers, freshwater must be conveyed from the natural reservoirs and areas of high precipitation to population centers or farmland.

The energy use of conveying water can vary widely due to the specific terrain that a given volume of water must traverse to move from source to point of use. On the low end of the range, conveying water may require almost no energy input at all. This refers to the case where the point of use is located near the source, and the source is at a much higher elevation than the point of use. In this case, gravity allows water to flow from the higher elevation to the lower elevation. If the height difference is enough such that the gravitational potential energy provided to the water is enough to overcome all friction losses and obstacles, then no energy input is required to convey this water.

Fortunately, this is the case for much of the agricultural water demand. The agricultural water demand is concentrated primarily in the Sacramento and San Joaquin Valley, located in the central area of the state and bordered by the northern and eastern mountainous regions.

Unfortunately, this is not the case for urban water use. For example, the South Coast region which accounted for 44.8 percent of total urban freshwater use is surrounded by the Tehachapi mountain range in Southern California [8]. Therefore, to convey water from the northern

sources, water must be conveyed over long distances and above high altitudes. Long transport distances require energy input to overcome friction losses. The need to overcome high altitudes requires energy input to push water volumes against gravity. Therefore, transporting water to this region is very energy intensive and requires multiple pumping stations that consume electric energy and natural gas.

The energy requirement to convey one million gallons (MG) of water from source to point of use can vary between 0-16,000 kWh/MG [63]. The typical energy intensity of conveying freshwater from state sources to water demand centers in Northern California is about 150 kWh/MG, whereas for Southern California this typical figure increases to 8,900 kWh/MG.

2.1.3.1.2.2. Energy Requirements for Water Treatment

Water treatment refers to the removal of compounds, micro-organisms, and other undesirable characteristics such as odor or turbidity from a volume of water extracted from a natural reservoir. Note that this is distinctly different than wastewater treatment, which refers to the same principle but applied to wastewater from urban use processes.

Depending on the end use of a given volume of water, it may have to undergo stages of water treatment. For example, water used for agricultural purposes does not typically require extensive treatment. Water used in agriculture is mostly applied for irrigation, and the level of minerals, micro-organisms and chemicals in non-contaminated freshwater resources is typically similar to or lower than that found in the soil. Therefore, most crops will not be sensitive to using heavily treated water versus lightly treated water. Additionally, some industrial processes can use water which does not require treatment. Many industrial processes use water as a diluting agent, which does not require extensive removal of trace compounds and micro-organisms.

Water used for residential and commercial purposes such as domestic use and drinking tends to require extensive water treatment. This water is regularly exposed to and ingested by humans and is subject to strict quality requirements to ensure safe exposure and ingestion. Treatment of this water is necessary to meet these quality requirements.

Water treatment involves a number of different processes that are aimed at processing input water to provide an output stream with desired characteristics. Conventional processes in order of occurrence include [65]:

- **Screening.** Water flows through screens to remove large pieces of debris.
- **Rapid Mixing.** This acts to allow chemicals added in later processes to trap particles more effectively.
- **Flocculation.** Chemicals with a high molecular weight are added to trap and remove fine particles suspended in the water.
- **Sedimentation.** This process allows large particles to settle out of the water. Approximately 85 percent of suspended mass is removed during this process and drained as sludge.
- **Granular Filters.** Water flows through filters of various sizes to remove extremely small particles in the fluid.
- **Disinfection.** Either chemical or radiation-based processes are applied to destroy disease-causing organisms and/or render them unable to replicate.

Of these conventional processes, only rapid mixing and disinfection can consume significant amounts of electric energy, and the latter only does so if radiation-based processes are used. Rapid mixing involves the operation of large electric motors and accounts for about 15 percent of the electric load demand of a large water treatment plant. The largest contributor to the electric load demand of a water treatment plant is due to water pumping to move water throughout the various processes, which accounts for 60.7 percent of the electric load demand for the plant [65]. For conventional processes, the energy intensity of water treatment plants is between 10 kWh/MG for groundwater and 78 kWh/MG for surface water, which is significantly lower than that for water conveyance. The combination of water conveyance and treatment contributed to 22.3 percent of water-related electricity use in 2001 [63].

Traditionally, water treatment has not consumed significant amounts of electric energy, due to the use of chemical-based disinfection processes. However, many conventional disinfection processes such as chlorination or use of hypochlorite have side effects or safety concerns which may prompt some plants to switch to alternative processes. Additionally, chemical methods of disinfection have varying effectiveness for destroying different types of organisms, whereas radiation-based methods are very effective for the organisms of concern. For example, chlorine gas used in chlorination is extremely toxic and can react with certain compounds to form carcinogens, and the transport of such gas is of concern. Other chemicals such as sodium dioxide are corrosive and can also react to form carcinogens.

The primary radiation-based disinfection process is ultraviolet (UV) radiation. This process involves flowing electric current through ionized mercury vapor in a sealed lamp to emit UV radiation into the water. UV radiation is ineffective if the water has a high turbidity; however, it

is extremely effective at eliminating threats from organisms of concern and does not introduce chemicals into the water. The major tradeoff, however, is that this process consumes a fairly large amount of electric energy relative to chemical processes. For medium-pressure UV lamps, the energy intensity of UV radiation can be as high as 160 kWh/MG, compared to almost zero for chemical-based methods [65]. Widespread use can significantly increase the electric energy consumption of water treatment plants, since this energy intensity is more than double that of all of the water treatment processes combined in a conventional water treatment plant.

An alternative method for water treatment is desalination. Desalination refers to a set of processes that is primarily used to remove salt from seawater or brackish water. As an added effect, desalination processes also remove other compounds and dissolved solids.

Desalination is being considered due to the desire to diversify California's water supply and increase reliability during drought periods [8]. Using desalination allows the impaired groundwater, brackish groundwater and seawater to contribute to the state's fresh water supply. Impaired groundwater refers to groundwater that does not meet water quality standards and is difficult to treat. Brackish groundwater refers to groundwater that is unsuitable for use due to a high salt content and is typically found in saline aquifers. Additionally, desalination is very effective at treating contaminated wastewater that contains specific compounds such as volatile organic carbons, nitrates, and pathogens. The benefits of using desalination are outlined in the California Department of Water Resources Water Plan Update [8].

From an energy consumption standpoint, however, desalination is extremely energy intensive for the primary methods used. The pumping of water to high pressures in reverse osmosis requires significant electric energy input. The vaporization of water requires a significant heat input,

typically from burning a fossil fuel or using a resistance heater which may consume significant amounts of electric energy. The energy intensity for desalination of seawater ranges from 9,780 to 16,500 kWh/MG, and that for brackish water ranges from 3,900 to 9,750 kWh/MG [66]. For comparison, the average energy intensity of the entire water infrastructure in supplying freshwater for urban use was estimated to be 3,950 kWh/MG in Northern California and 12,700 kWh/MG in Southern California [63] in 2005. If widely used, desalination can contribute to significant increases in the electric load demand, especially since conventional water treatment processes have fairly low energy intensities.

2.1.3.1.2.3. Energy Requirements for Water Distribution

Water distribution refers to the delivery of water to end users. After water has been conveyed from sources to the point of use and treated, water must be distributed to each individual end user. This involves the pumping of water through a network of pipes and storage tanks.

In the water distribution system, water must be continually pressurized to ensure adequate water delivery to end users located very far away from pumping stations. Pumps operate continuously to maintain pressure and move water to end users, requiring electric energy input. Distribution in certain regions may require more electric energy input than others, depending on the elevation differences between pumping stations and end users. Additionally, water distribution pipes must be periodically flushed to prevent the buildup of micro-organisms in static water environments and to prevent corrosion of pipes.

According to a survey by EPRI [67] and figures from the CEC [63], the energy intensity of water distribution was estimated to be about 1,200 kWh/MG on average.

2.1.3.1.2.4. Energy Requirements for Wastewater Treatment

After water is used for various purposes, it leaves the point of use as wastewater. This applies mostly to urban water use, as water used for agricultural purposes such as irrigation is typically absorbed into the crops or evapo-transpired into the atmosphere. Wastewater contains various contaminants and micro-organisms and must be treated such that it can be re-introduced into the natural environment without detrimental impacts or repurposed for other uses. This process is essential for protecting public health and the quality of water resources.

In general, wastewater treatment processes are very similar to the water treatment processes described earlier. The key difference between wastewater and water treatment is that wastewater contains a high concentration of organic solid waste. These solids must be broken down and removed before disinfection. Therefore, after the removal of debris but before flocculation/sedimentation, wastewater treatment adds the step of introducing biological agents to break down organic waste. Wastewater is placed in a biological reactor where aerobic bacteria are introduced to break down organic wastes into carbon dioxide and water to the extent possible, with the remainder contributing to sludge. The input stream is then separated into effluent and sludge.

The sludge is removed via sedimentation and placed in another biological reactor with anaerobic bacteria called an anaerobic digester to produce biogas. The biogas can be burned to offset the wastewater treatment plant's heating needs or electric energy needs by use of an on-site gas turbine thermal plant.

The effluent is then subject to the same processes as standard water treatment for the removal of particles and disinfection. Once fully treated, this water can be re-introduced into a river or other natural reservoir, used for irrigation or other uses depending on the degree of treatment. Stricter

water quality standards require more thorough treatment of wastewater. Additionally, wastewater may need to be treated to different degrees depending on the intended re-use of treated water.

Similar to water treatment plants, the vast majority of electric energy input in wastewater treatment plants is used to pump wastewater. Since wastewater contains higher concentrations of organic solids compared to natural water, the energy required for pumping is increased since solids require more energy to transport.

The degree of treatment required also affects the energy consumption of the plant. A more thorough treatment of wastewater streams requires additional processes and steps which directly require electric energy input or indirectly increase electric energy consumption by increasing the pumping requirements. For example, an advanced wastewater treatment plant with a nitrification process can produce treated effluent that is very clean and suitable for a wide range of end uses. The tradeoff, however, is that such a plant uses between 62.9 and 231.5 percent more electric energy compared to a simple wastewater treatment plant [67] for technology levels as of 2002.

The energy intensity of a typical wastewater treatment plant operating in California as of 2004 was estimated to be about 2,500 kWh/MG. This figure is based on a survey of multiple operating wastewater treatment plants as described by the CEC [63]. Many of these plants already use nitrification and advanced wastewater treatment as described in the EPRI report, therefore a switch from simple systems to “advanced” systems for 2002 technology levels would not be expected to increase electric energy consumption. However, stricter water quality standards and the potential for new uses of recycled water (i.e. for drinking water) on a wide

scale may require more extensive water treatment levels that might require more electric energy input.

2.1.3.2. Water Demand

Water is used for a variety of tasks ranging from agricultural to urban processes. Before discussing the major end-uses of water, it is necessary to make the distinction between three terms that are used when discussing aggregate water usage:

- **Withdrawal:** Water withdrawal refers to the extraction of water from a reservoir for use in a societal task. Water that is withdrawn but not consumed is returned to a reservoir at some point in the future. It is important to note, however, that the extracted water may not necessarily be returned to the same reservoir from which it was extracted. Additionally, extracted water may not necessarily be returned to reservoirs immediately after use. Examples include once-through cooling of thermal power plants located at a river or on the coast. Water is taken in to the plant, absorbs heat from the gas-turbine or steam-turbine cycle, and is released back into the river or ocean [40].
- **Consumption:** Water consumption refers to the use of water for a task that renders it unable to be returned to the reservoir from which it was extracted. Examples include water use for irrigation. Water is used to hydrate farmland, where it is absorbed into plants and/or evaporated/transpired into the atmosphere. Additionally, any process which contaminates the water used by adding substances to it (such as cleaning) counts as consumption, since this water cannot be re-introduced into the environment without treatment [40]. If this water is treated and injected into a groundwater reservoir or river, however, it will only be counted as withdrawal and not as consumption.

- **Demand:** Water demand refers to the amount of water that must be delivered to all end-users to allow societal tasks to be performed. This differs from the previous two terms in that it does not make any distinction between where the water comes from (i.e. whether it is water being re-used or newly extracted from a reservoir) or where the water is deposited after it is used to perform the desired tasks.

Qualitative trends in water demand drive trends in water consumption and withdrawal. For example, increased water demand typically denotes increases in water withdrawal and consumption. It is important to note, however, that the quantitative water demand is not exactly the same as the quantitative amount of water withdrawal or consumption. For example, consider two end uses that require 100 gallons of water for a total water demand of 200 gallons. If these 200 gallons were provided by water that was newly extracted from a reservoir directly, this would require a water withdrawal of 200 gallons. If 100 of these gallons were provided from re-used water, however, then the required water withdrawal would only be 100 gallons. Also, depending on what happens to the water after usage, this demand may or may not contribute to water consumption. As a general rule, however, higher water demand drives similar trends in water withdrawal and consumption.

Water consumption is typically discussed for freshwater resources only, since saline water from the ocean is generally not used in a manner that renders it unsuitable for return to the ocean. The two main uses of saline water are for the cooling of thermal power plants. In the former, the water is simply heated up and returned to the ocean at a higher temperature. Water withdrawal on the other hand, may or may not include saline water extraction depending on the institute providing the discussion.

It is also important to note that trends for water withdrawal do not necessarily imply the same behavior in water consumption. For example, the re-use of wastewater for non-potable uses reduces the need for additional water that would have needed to be extracted to satisfy those non-potable uses. Therefore, wastewater re-use reduces water withdrawal. This process, however, does not reduce water consumption. The same amount of water that was extracted from the reservoir ultimately ends up becoming unsuitable for being returned to it. The primary difference is how many uses that quantity of water was able to satisfy [68].

These examples demonstrate a key difference between supply and demand in the electricity and water sectors. In the electricity sector, the electric load demand has a one-to-one correspondence with electric power production. This occurs because electric energy, once used to perform a task, is irrecoverable. In the water sector, the amount of water extracted from reservoirs may not be exactly equal to the water demand, since a given quantity of water can be treated and re-used to satisfy multiple demands.

The end uses of extracted water can be sorted into three primary categories [8]:

1. **Agriculture.** Agricultural water refers to water that is primarily used for the irrigation of crops, the raising of livestock and the sustenance of aquaculture farms. This application uses freshwater exclusively. Irrigation is the dominant water use subcategory of agricultural water use and typically contributes to water consumption, since most of the water used in this fashion is absorbed by the crops and / or returned to the atmosphere by evapotranspiration and only a small amount contributes to runoff that recharges water reservoirs.

2. **Urban.** Urban water use refers to “the use of potable and non-potable water for urban purposes including, but not limited to, residential, commercial, industrial, recreation, energy production, military, and institutional classes”. This essentially refers to all water that is used for domestic or industrial processes.
3. **Environmental.** Environmental water is defined as “minimum flow levels of a specific quality that is needed in order to assure the continued viability of fish and wildlife resources for a particular water body. This is water that is used to maintain and enhance the beneficial uses related to the preservation and enhancement of fish, wildlife, and other aquatic resources or preserves as specified in the Porter/Cologne Water Quality Control Act, 2008”. This essentially refers to water resources that are used to maintain aquatic ecosystems in the natural environment.

Of these three end-use categories, typically only agricultural and urban water end-uses are taken into account when discussing water usage. These two categories refer to water that is directly used to drive society-related processes, whereas environmental water is used for environmental stewardship and is therefore not ‘used’ by society, even though a significant portion of water resources are applied for this function. The discussion here will follow this convention and refer to water use in terms of agricultural and urban end-uses only.

The extent to which each category contributes to water consumption and withdrawal varies widely by state. For example, states on the coast are able to use saline water to cool thermal power plants, where inland states will have to use freshwater to do so without dry-cooling. In the former, thermal power plant cooling does not contribute to freshwater withdrawal, whereas in the latter it may be a significant contributor to freshwater withdrawal. Additionally, the extent of

agriculture and industry varies significantly between states. For example, New York has a large population without the presence of a booming agriculture sector. Consequently, urban water use in New York comprises 99.91 percent of total water withdrawal in the state. On the other extreme, the state of Montana has a very small population but a moderately large agriculture sector. Consequently, agriculture comprises 96.5 percent of total water withdrawal in the state [40].

California represents a unique balance between the different end uses of water. The state has a large urban population as well as a very large agriculture sector. As a result, the water withdrawal (including saline water) of the state is the largest among all of the states in the U.S. In California, agriculture accounts for 55.2 percent of total water withdrawals, with 53.4 percent due to the irrigation of crops alone. Urban water use is also a major factor due to **cooling requirements for thermal power plants, accounting for 27.6 percent of total water withdrawals alone** and using almost exclusively saline water resources [40].

When discussing freshwater resource consumption, however, the outlook is much different. Agricultural water use comprises the vast majority of water consumption in the U.S. and in California. For example, in 2005, agricultural water use accounted for 79 percent of freshwater resource consumption, with irrigation alone accounting for 66 percent [8] in California. In the U.S., agricultural water use was estimated to comprise 83.9 percent of total freshwater consumption, with irrigation alone accounting for 80.6 percent in 1995 [68]. From the standpoint of freshwater consumption, urban water use accounts for only a small amount of total consumption. The behavior of freshwater consumption is more strongly tied to the water-use efficiency of agricultural processes.

Trends in water withdrawal and consumption have been difficult to predict. In contrast to electric energy where every kWh of energy consumed is monitored at the end use, not all water uses are monitored. Water usage statistics such as those just presented are composed from a combination of what uses are measured and estimates for those which are not monitored. Different institutions have also produced slightly different estimates. An example of different estimates of applied freshwater, which refers to the water withdrawal for freshwater only, is presented for the California Department of Water Resources and the U.S. Geological Survey from 1960 to 2000 in Figure 37 [69]:

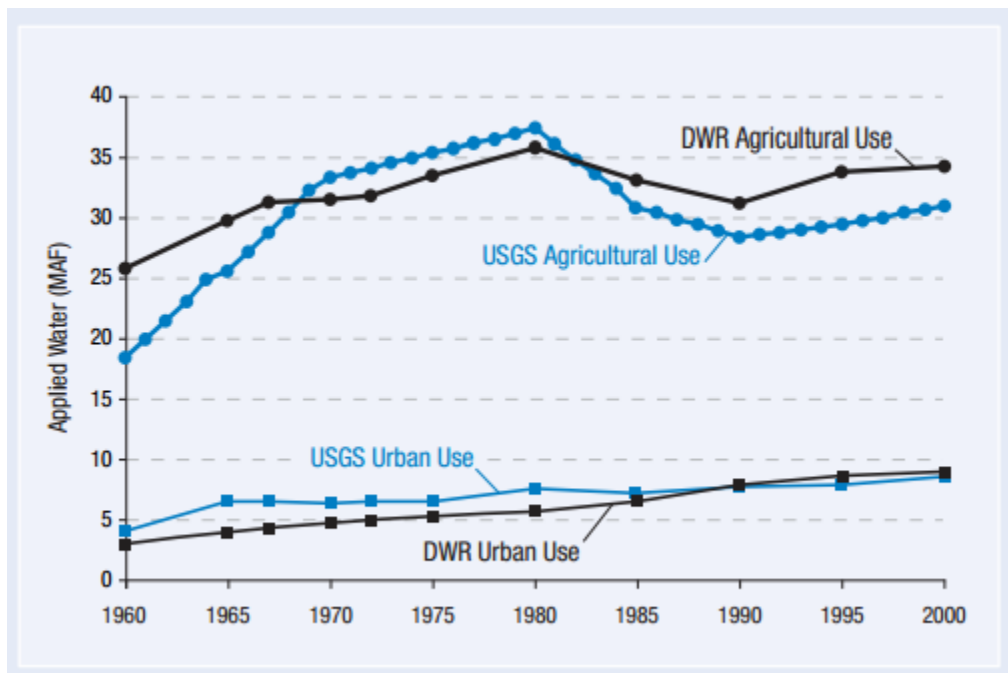


Figure 37 - Historical Agricultural and Urban Water Use for California from 1960-2000 [69]

These different institutions produced slightly different estimates of historical freshwater withdrawal, due to differences in estimate methods for water withdrawal that is not measured. The qualitative traits for these estimates, however, are somewhat similar for both urban and agricultural freshwater use. Urban freshwater use is strongly tied to population, and has grown

steadily with it. Without changes in urban water use efficiency, this trend is expected to continue. However, a number of measures are in place that are aimed at improving urban water usage efficiency, including but not limited to the increased use of recycled water and reductions in water usage for landscaping [8]. Current regions with high populations already employ extensive water efficiency measures and have limited the growth in water demand due to population compared to business-as-usual levels [9]. Note that this trend is for urban **freshwater** withdrawal and does not take into account the extensive saline water withdrawal for cooling thermal power plants.

Agricultural freshwater withdrawal, however, has varied throughout history. Agricultural water use is indirectly tied to population, since more crops and livestock are required to feed a larger population. California, however, has made continuing strides in improving agricultural water use efficiency. Between 1972 and 2001, improvements in irrigation techniques decreased surface water use for irrigation by about 30 percent [70]. Additionally, the average freshwater withdrawal used per acre of farmland was reduced from 3.5 acre-feet per acre of farmland as an average between 1960 and 1989 to 3.2 acre-feet per acre of farmland between 1990 and 2005 [9]. Improvements in agricultural water use efficiency are focused on three main categories as stated in [8]:

1. **Hardware.** Improving on-farm irrigation systems and water supplier delivery systems
2. **Water management.** Improving management of on-farm irrigation and water supplier delivery systems
3. **Crop water consumption.** Reducing non-beneficial evapotranspiration and using crops with lower water consumption.

2.2. Technology and Strategy Options

The following is a general overview of sustainability-oriented technology or management

options for helping individual resource sectors contribute towards meeting holistic sustainability goals.

2.2.1. Electricity Sector

2.2.1.1. Renewable Resources

2.2.1.1.1. Wind Power

Wind power is the extraction of kinetic energy contained in moving air masses constituting a prevailing wind. Loosely speaking, kinetic energy is imparted onto an air mass due to differential heating in the Earth's atmosphere which, along with other factors such as terrain, creates pressure differentials that promote airflow. Depending on application, the kinetic energy in the wind is either used directly as mechanical energy (shaft work) in the case of windmills, or converted to electric energy via the use of a wind turbine.

2.2.1.1.1.2. Power in the Wind

A particular derivation for determining the amount of power that can be extracted from a given flowing fluid mass is provided by Tester [71] using a conservation of momentum analysis.

Consider a control volume that encloses a circular disc of area equal to the swept area of a wind turbine rotor:

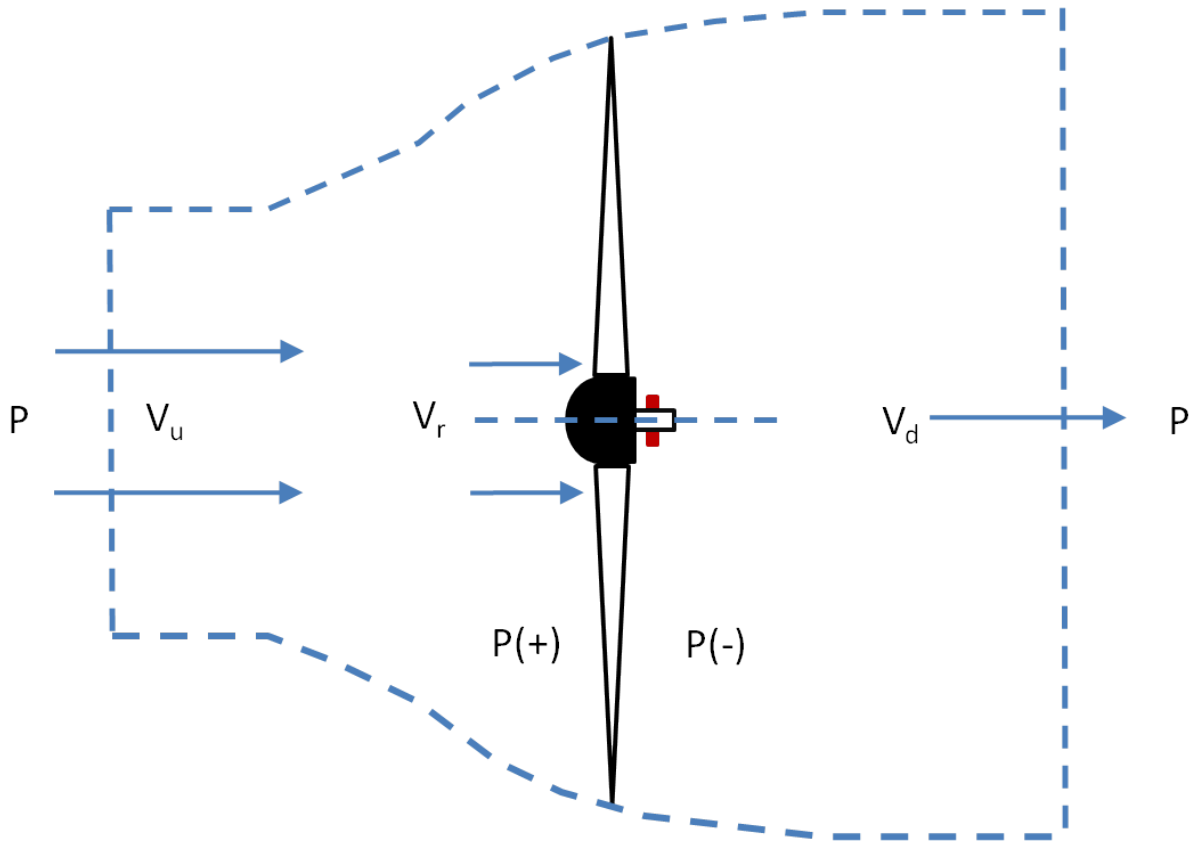


Figure 38 - Control Volume around a Wind Turbine with Upstream and Downstream Flows

The flow in and out of the control volume is assumed to be axial, incompressible, and irrotational, and the disc is considered to be massless. The bounds of the control volume are such that the mass flow rate is fixed. Therefore, the force (F) exerted by the flow on the disc is equal to the rate of change of momentum between the upstream and downstream flows multiplied by the area of the disc:

$$F = \rho A_r V_r (V_u - V_d)$$

Where ρ is the density of the air mass, A_r is the swept area of the disc, V_r is the air velocity immediately upstream of the disc, V_u and V_d are the air velocities far upstream and far downstream of the disc.

The power extracted by the disc is then:

$$P_r = F \cdot V_r = \rho A_r V_r^2 (V_u - V_d)$$

Bernoulli's equation can then be applied for streamlines originating far upstream of the control volume and terminating just upstream of the rotor, and streamlines originating just downstream of the rotor and terminating far downstream of the rotor:

$$P^+ + \frac{1}{2} \rho V_r^2 = P + \frac{1}{2} \rho V_u^2$$

$$P^- + \frac{1}{2} \rho V_r^2 = P + \frac{1}{2} \rho V_d^2$$

Where P^+ is the pressure immediately upstream of the disc, P^- is the pressure immediately downstream of the disc and P is the free stream air pressure.

The pressure drop across the rotor is then given by:

$$P^+ - P^- = \frac{1}{2} \rho (V_u^2 - V_d^2)$$

The force on the disc is therefore the area of the disc multiplied by the pressure drop:

$$F = A_r (P^+ - P^-) = \frac{1}{2} \rho A_r (V_u^2 - V_d^2) = \rho A_r (V_u - V_d) \left(\frac{V_u + V_d}{2} \right)$$

Comparing this expression of F to that presented prior:

$$\rho A_r (V_u - V_d) \left(\frac{V_u + V_d}{2} \right) = \rho A_r V_r (V_u - V_d)$$

$$\therefore V_r = \left(\frac{V_u + V_d}{2} \right)$$

Therefore, in terms of the upstream and rotor velocities, the power extracted by the rotor (P_r) is given by:

$$P_r = 2\rho A_r V_r^2 (V_u - V_r)$$

2.2.1.1.1.2. The Betz Limit

Using the same control volume analysis, the power coefficient can be obtained. The power coefficient (C_p) is defined as the total amount of power extracted by the rotor as a fraction of the total amount of power in the incident wind:

$$C_p = \frac{P_r}{P_u} = \frac{2\rho A_r V_r^2 (V_u - V_r)}{\frac{1}{2}\rho A_r V_u^3} = \frac{4}{V_u^3} [V_r^2 (V_u - V_r)]$$

The maximum power coefficient can then be obtained as follows:

$$\frac{\partial C_p}{\partial V_r} = \frac{4}{V_u^3} [2V_r V_u - 3V_r^2] = 0$$

$$[2V_r V_u - 3V_r^2] = 0$$

$$\frac{V_r}{V_u} = \frac{2}{3}$$

Rewriting the expression for the power coefficient as:

$$C_p = \frac{4}{V_u^3} [V_r^2 (V_u - V_r)] = 4 \left[\left(\frac{V_r}{V_u} \right)^2 - \left(\frac{V_r}{V_u} \right)^3 \right]$$

Substituting:

$$C_{p,max} = 4 \left[\left(\frac{2}{3} \right)^2 - \left(\frac{2}{3} \right)^3 \right] = 0.593 \text{ or } 59.3\%$$

This number is known as the Betz limit, which represents the maximum fraction of power (and energy) that can be extracted by any aerodynamic device from an incident, prevailing wind under ideal conditions. Real-world wind turbines exhibit lower power coefficients due to losses such as friction and flow separation on the blades.

2.2.1.1.1.3. Wind Turbine Basics and Relation to Power Variability

A wind turbine is a device which creates mechanical power by utilizing airfoils that create aerodynamic forces (lift) to rotate a mechanical shaft. A basic diagram of major wind turbine components is presented in Figure 39:

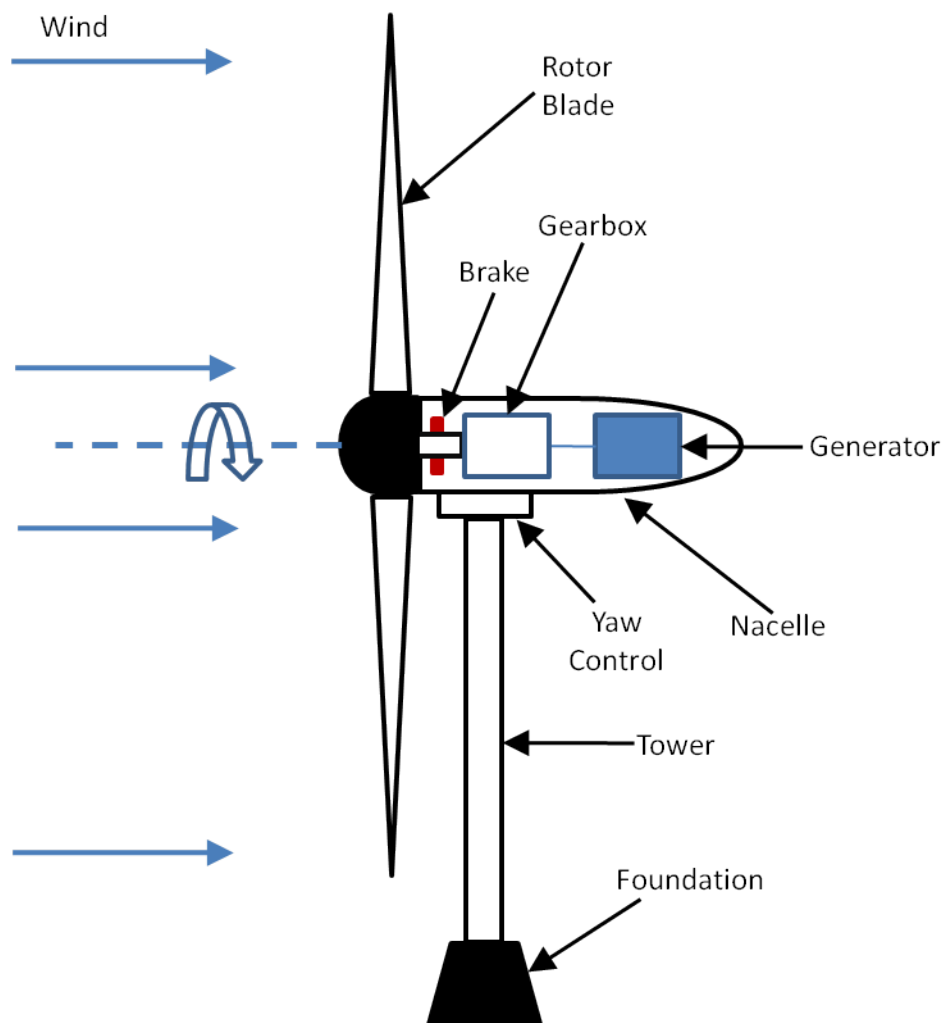


Figure 39 – Schematic of a Typical Modern Wind Turbine

The shaft is connected to an electric generator which provides electricity output that is in sync with the electric grid frequency. In between the rotor blades and the electric generator is a gearbox which serves to reduce the rotational speed of the rotor blades to a speed suitable for the electric generator. A wind turbine may have multiple electric generators to allow different operational speeds while maintaining a constant frequency in the electric output, or a variable-speed electric generator controlled by power electronics to maintain the frequency of the power output. The gearbox, generator, and auxiliary components are housed inside a nacelle which is suspended above ground by a tubular tower.

In order to make the most effective use of the incident wind and preserve the reliability of the turbine, different components of the wind turbine have different capabilities. Nacelles are often equipped with a yaw control system, which allows the turbine to rotate such that the swept area is always facing the incident wind and therefore generating the maximum aerodynamic torque. There is typically a maximum angular velocity at which the blades are allowed to rotate due to mechanical strength and fatigue limits on the rotor blades and other components. Since the amount of power extracted from the wind is a function of the wind speed and therefore angular velocity, the blades are often equipped with pitch control mechanisms to hold the angular velocity of the blades steady after the incident wind speed reaches a certain level. The wind speed at which this occurs is often very close or equal to the rated speed of the turbine. Also, in the event that the wind speed is excessive and the blades are already pitched to provide minimum torque, wind turbines are often equipped with mechanical brakes to stop the rotation of the turbine completely. The speed at which this occurs is called the cut-out speed. This procedure is

implemented such that the excessive amount of power in the incident wind is prevented from inducing high stresses and damaging wind turbine components.

These basic control capabilities are present on all modern wind turbines. With these strategies in place, the power curve of a modern wind turbine is often shaped as displayed in Figure 40:

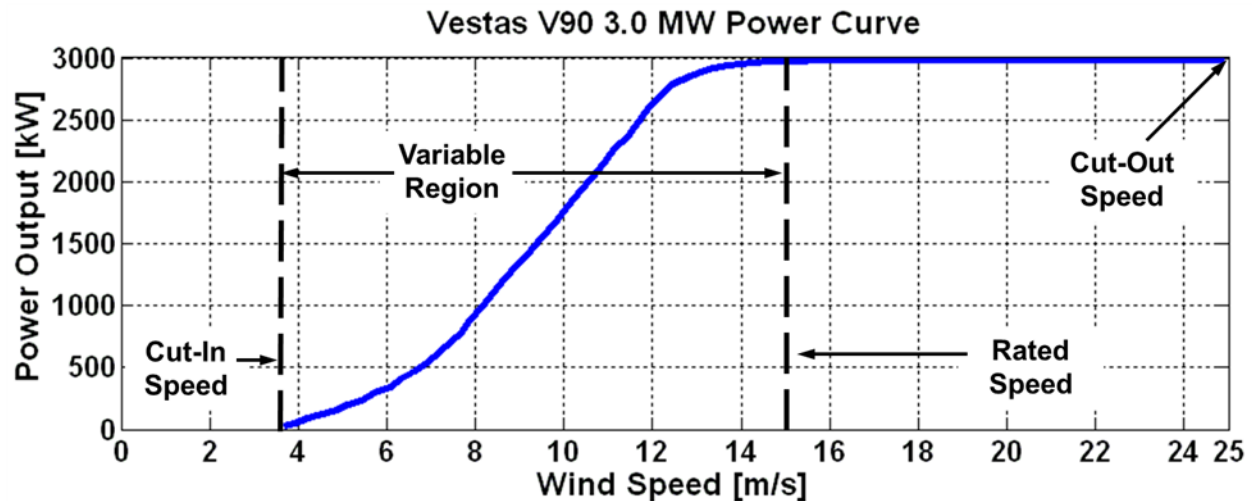


Figure 40 - Power Curve of a Typical Modern Wind Turbine

The power curve of a wind turbine exhibits a number of key features. The wind speed at which the incident wind exerts a sufficient amount of torque to rotate the blades is called the cut-in speed. Below this wind speed, the turbine outputs no power. At wind speeds higher than this, the power output of the turbine varies in a cubic fashion with increasing wind speed until the rated speed is reached. The cubic shape of this “variable region” is consistent with the principle of power being a cubic function of fluid velocity as presented prior. As the rated speed is reached and exceeded, the rotor blades change pitch to maintain a constant angular velocity and power output. This persists until the wind speed increases to a point where it induces unacceptable stress levels on the turbine components, called the cut-out speed. At this point, the brakes are applied and the turbine is stopped as quickly as possible, reducing its power output to zero.

The features of the common wind turbine power curve have many implications for the variability of wind power. In the “variable” region, the power output is loosely a cubic function of wind speed, therefore small perturbations in wind speed can cause large changes in turbine power output. For example, a doubling of the wind speed within this region will multiply the power output by a factor of eight. Even small oscillations can cause rapid, significant fluctuations in turbine power output. Also, the existence of a cut-out speed, while necessary for maintenance of turbine components, can occasionally produce large transients in turbine power output. For example, if a turbine experiences cut-out due to the onset of high incident wind speeds, the power output from such turbine will drop from its rated power (high) to zero power in a very short amount of time. The opposite may occur as well: as soon as the wind speed drops below the cut-out speed, the brakes are released and the turbines are brought back to rated power in a short timeframe. This type of behavior is undesirable from a dynamic standpoint, especially at the wind farm level.

In addition to variability caused by the operation of the turbine and the fundamental relationship between wind speed and aerodynamic power, there exists significant variability in the incident wind speed. The wind speed at any given location is determined by regional weather patterns influenced by a number of factors including temperature, pressure, and geographical features which may alter the character of a large scale air flow. For example, an air flow which passes over rough, hilly terrain may exhibit increased amounts of turbulence and unsteadiness. An explicit examination of characterizing the variability of wind speed in terms of its corresponding physical factors is beyond the scope of this study. One should be aware, however, that the compounding of variability in wind speed and turbine characteristics serves to render wind power as a highly variable energy resource.

2.2.1.1.2. Solar Power

Solar power refers to the conversion of electromagnetic energy in the form of radiation from the sun to forms such as electric or thermal energy for practical uses. This is accomplished by absorbing the radiation directly for space or water heating, concentrating to a heat transfer fluid for steam generation in a steam-turbine cycle power plant, or absorbing the radiation to promote the flow of electricity in semiconductors in the case of photovoltaics.

2.2.1.1.2.1. Solar Radiation Basics

The extremely high temperatures of the Sun produce blackbody radiation that propagates through space and strikes the Earth's atmosphere. The amount of radiation striking the outer edge of the atmosphere any given moment is relatively constant, varying between $1,354 \text{ W/m}^2$ and $1,365 \text{ W/m}^2$, due to variations in the distance between the Earth and the Sun throughout the year. The amount of that radiation that continues through the atmosphere to strike a given site on Earth's surface varies considerably due to the transmissivity of the atmosphere and the location of the site. Lower latitudes (near the equator) tend to receive a higher amount of radiation since such locations tend to have a more direct line of sight to the sun throughout the course of a given day. Dry climate areas tend to receive higher amounts of radiation due to high atmospheric transmissivity and decreased scattering and reflection due to atmospheric objects.

Radiation striking the atmosphere may continue to propagate toward a given area on the Earth's surface either as direct or diffuse radiation. Direct radiation is the component of the sun's radiation which arrives at a horizontal surface at ground level without interruption, in a straight line from the sun. Diffuse radiation is the component of the sun's radiation which arrives at a horizontal surface at ground level after being reflected from or scattered by atmospheric objects such as clouds or airborne particles. The types are displayed in Figure 41:

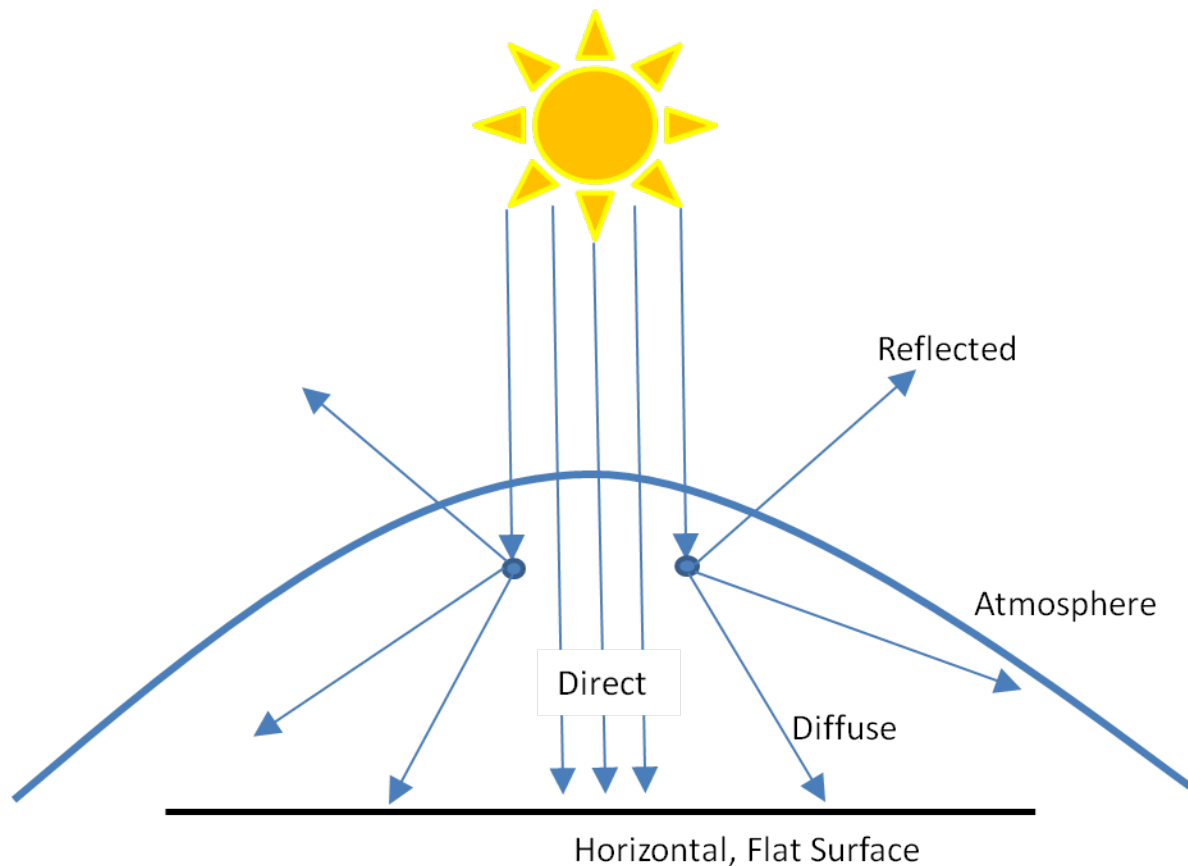


Figure 41 - Components of Solar Radiation

2.2.1.1.2.2. Variation in Solar Radiation

The amount of incident solar radiation striking a given area on the Earth's surface varies considerably in time based upon a number of factors. Before examining the details of such factors, it is important to make the distinction between cyclical variations and non-cyclical variations.

Cyclical Variations are changes in the solar radiation profile of a given site that occur with an observed periodicity. The most prominent examples of such include the diurnal variation of solar radiation due to the rotation of the Earth. The incident radiation changes from zero to a finite amount in the very early morning to a peak value at noon, and dropping back to zero during the onset of the nighttime hours. A second example is the non-weather induced seasonal variation of

radiation that occurs at a given site due to changes in the sun's altitude angle relative to given latitudes, as displayed in Figure 42, sourced from [71]:

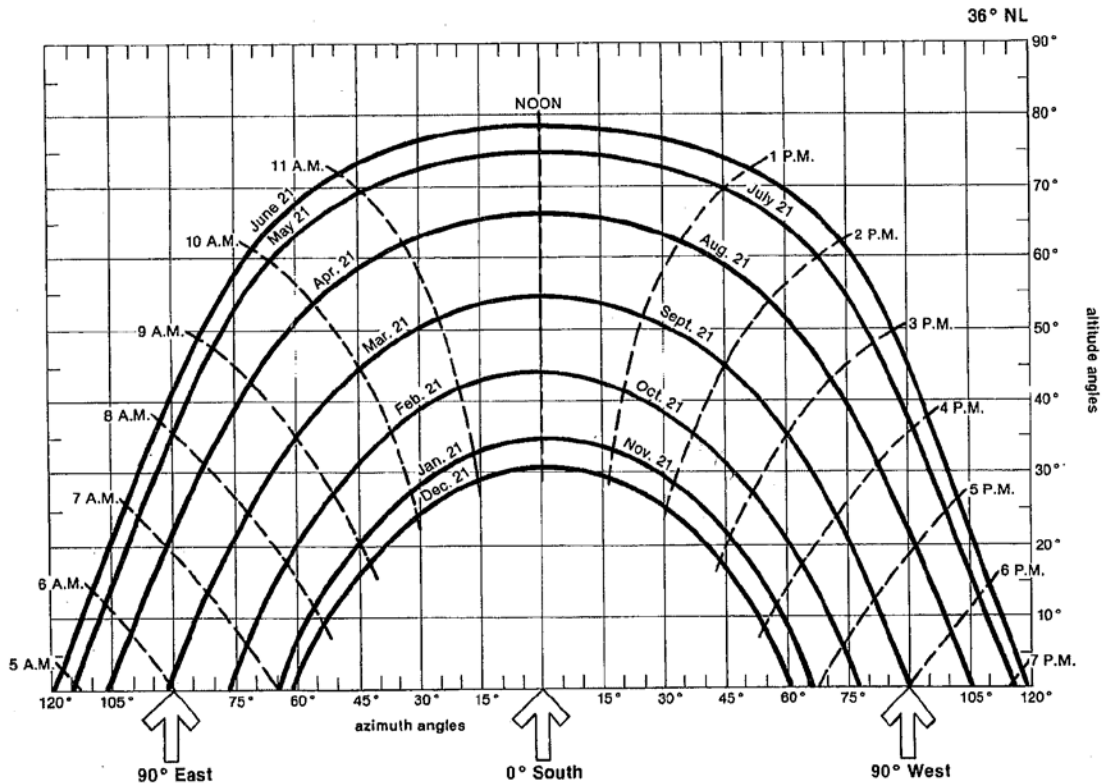


Figure 42 - Variations in the Sun's Altitude Angle as a function of Time of Day and Azimuth Orientation for a 36 degree Latitude.

Additional cyclical variations may be present at certain regions due to regularly occurring weather patterns (such as the Marine Layer effect in the Southern California Coastal Region). Overall, cyclical variations in solar radiation are generally caused by factors which far transcend the spatial scale of a given site, and tend to occur over relatively long timescales (Daily, Monthly, Seasonal, Yearly).

Non-Cyclical Variations are changes in the solar radiation profile of a given site that do not exhibit any typical periodicity. The most prominent example of such is the passing of a broken cloud pattern over a particular land area, as shown in Figure 43:



Figure 43 - Intermittent Cloud Pattern (Picture taken by Dr. Tim M. Brown on 8/9/2010)

The magnitude and occurrence of fluctuations in solar radiation due to such an event is difficult to predict or match to any regular pattern, and exhibits a profile similar to that in [72]. Most cloud pattern passes, due to the distribution of cloud size within the pattern and changes in cloud velocity, can be viewed as causing a non-cyclical variation. Overall, non-cyclical variations in solar radiation are generally caused by region or site-specific factors and tend to cause fluctuations that occur over relatively short timescales (sub-daily, sub-hourly, sub-minute).

In terms of load balancing, cyclical and non-cyclical variability types require different strategies to be accommodated on a system such as the electric grid.

2.2.1.1.2.3. Solar Photovoltaics

A solar photovoltaic cell is a device which converts radiant (electromagnetic) energy directly into electric energy via the photoelectric effect. Cells are combined in series to form modules, arrays, and entire photovoltaic systems. The fundamental operating principles of the photovoltaic cell are discussed herein.

The photoelectric effect is the excitation or ejection of electrons from their resident atoms in a material upon exposure to electromagnetic radiation. Within materials such as conductive metals or semiconductors, there exist certain energy levels which electrons can occupy, two of which are of interest to the photoelectric effect: the ‘valence’ band and the ‘conduction’ band. The valence band is comprised of the highest energy levels that electrons bound to a certain atom can occupy at absolute zero temperature. The conduction band is comprised of the energy levels above that of the valence band, where an occupying electron contains sufficient energy to be released from binding with its resident atom and move about the atomic lattice of the material. When a photon of sufficient energy (higher than that of the energy gap between valence and conduction bands) is absorbed by an electron in the valence band, it is excited into the conduction band and is therefore allowed to move about the material, as shown in Figure 44, sourced from [73]:

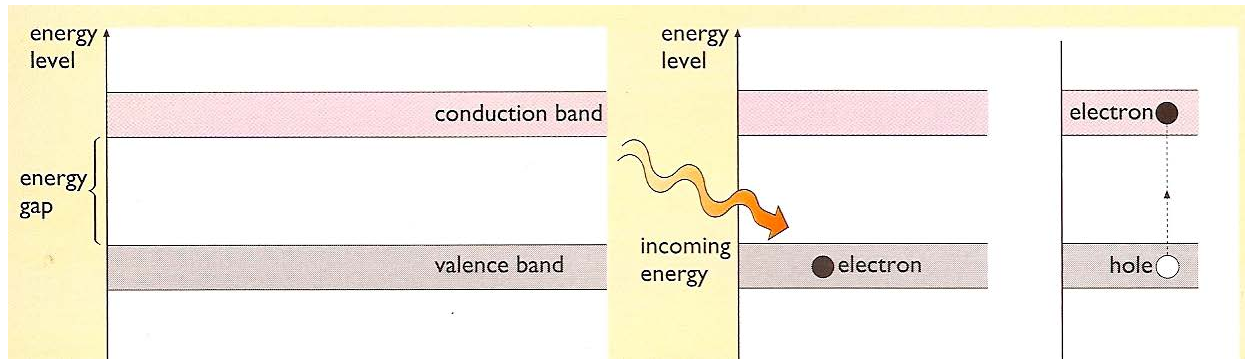


Figure 44 - The Photoelectric Effect in terms of Semiconductor Energy Levels. [73]

A photovoltaic cell takes advantage of this effect by creating a voltage difference within the material to direct the flow of electrons. This is accomplished by the use of a series of p-n junctions, comprised of p-type and n-type semiconductors. P-type semiconductors are materials which have been doped with impurities to become electron-deficient. N-type semiconductors are materials which have been doped with impurities to be capable of providing excess electrons. The junction therefore has a small voltage difference due to these properties. In the presence of light, the number of free electrons and electron holes in the n and p-type semiconductors increase respectively, increasing the voltage difference. When these materials are connected through a load, electrons flow from the n-type material through the load, deliver power, and combine with the electron holes in the p-type material. In terms of energy levels, this is displayed in Figure 45:

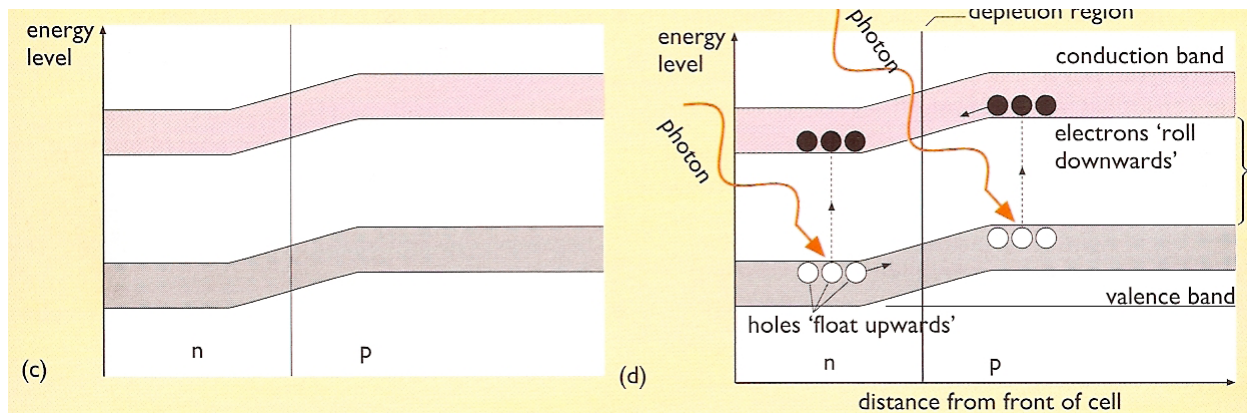


Figure 45 - Photoelectric Effect on a P-N Junction [73]

The photovoltaic effect is a phenomenon which occurs on timescales on the order of milliseconds or less. When light is incident on a photovoltaic panel, electricity production from the panel occurs only milliseconds after the light strikes it. The same principle applies when the intensity of light is suddenly reduced. This property is in stark contrast to electricity producing systems such as conventional power plants and wind turbines, both of which contain a certain amount of physical inertia which dampens the response of the system to input (wind speed, fuel) fluctuations on very fast timescales. Since the photovoltaic effect occurs on a timescale which is much smaller than those which are relevant to the load-balancing of the electric grid, variations in solar photovoltaic power output can be considered essentially identical to that exhibited by solar radiation. Under the presence of certain weather patterns, solar radiation has been demonstrated to exhibit significant dynamics.

2.2.1.1.2.4. Solar Thermal Power

Solar thermal power refers to the use of solar radiation as the heat source for a thermal power plant cycle as opposed to fossil fuels, usually taking the form of a steam-turbine based power plant. To provide sufficient heat input to reach high temperatures, diffuse solar radiation must be concentrated by various means and be absorbed by a working fluid and transferred to the

working fluid of the steam turbine cycle. A generic schematic of a simple solar thermal power plant is presented in Figure 46:

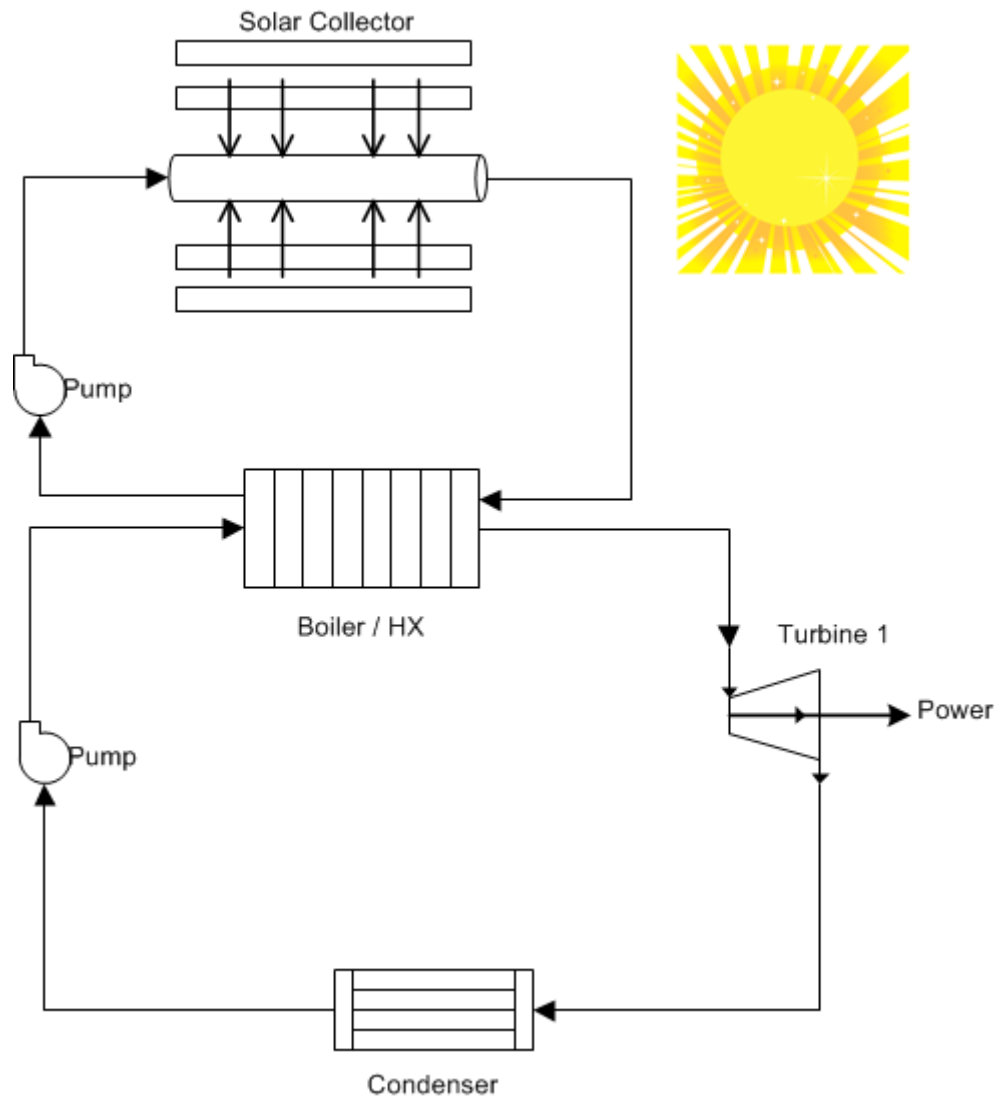


Figure 46 - Simple Schematic of a Solar Thermal Power Plant

Incident solar radiation is concentrated onto pipes containing a working fluid such as oil that is continually circulated in the upper loop. After being heated, the oil passes through a heat exchanger where it releases heat to superheat steam, which is the working fluid of the steam-turbine cycle in the lower loop. The working fluid of the upper loop must have a high boiling

point such that it does not vaporize (and reduce its heat conductivity) and is able to superheat the steam in the lower loop. Other configurations can concentrate solar radiation directly onto the pipes in the steam-turbine cycle, but this can pose practical challenges related to managing the heat transfer into a working fluid that is changing phase.

The solar collector can have a number of different configurations, each with their respective advantages and disadvantages. These types are outlined briefly as follows:

Parabolic Trough collectors use a set of linear, parabolic mirrors to focus solar radiation onto absorbers located on their focal lines, with each mirror strip having its own absorber tube as presented in Figure 47:

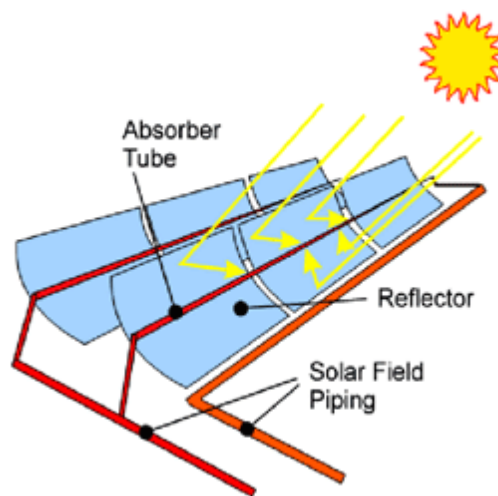


Figure 47 - Parabolic Trough Solar Collector

These systems can reach concentration ratios of up to 80x, and operating temperatures up to 400°C [74, 75]. To ensure optimal concentration, these units also utilize 1-axis (azimuth) tracking to follow the position of the sun in the sky. These systems have been in use in California for over 20 years, in installations such as the Solar Energy Generating System (SEGS) at Kramer Junction with a combined capacity of 354 MW.

Power Tower collectors utilize a centrally-located receiver which stores and circulates a very high temperature working fluid, upon which solar radiation is concentrated. Concentration occurs by the use of a circular arrangement of mirrors using 2-axis (tilt and azimuth) tracking to redirect incident radiation, as presented in Figure 48:

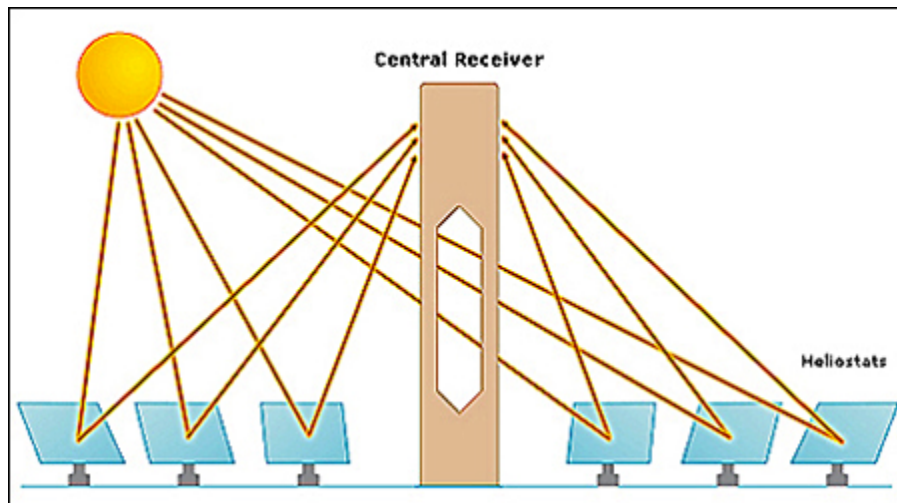


Figure 48 - Power Tower Solar Collector

These systems can reach concentration ratios of greater than 1000x and operating temperatures of up to 600°C, giving rise to high thermodynamic cycle efficiencies [74, 75].

Linear Fresnel collectors are similar to parabolic trough collectors, except that the absorber tubes are centralized (not specific to each mirror strip) and the mirrors are flat, as presented in Figure 49:

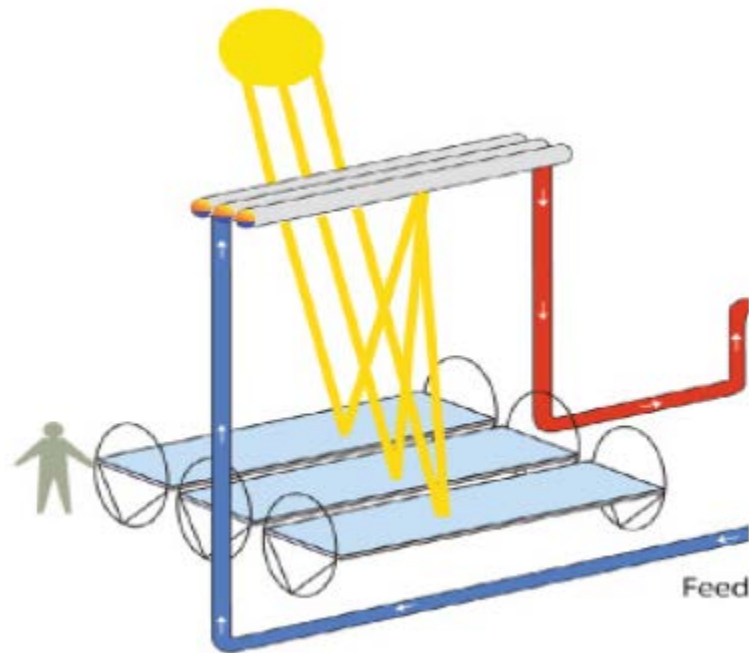


Figure 49 - Linear Fresnel Solar Collector

This allows more control over the concentration ratio compared to parabolic trough systems, since the number of mirrors focused on the absorber pipes can vary. Additionally, these systems can be easier to maintain. Linear Fresnel system can reach working temperatures up to 400°C.

Dish Stirling collectors use a parabolic mirror to focus solar radiation onto a point to directly heat up the working fluid of a Stirling engine, as presented in Figure 50:

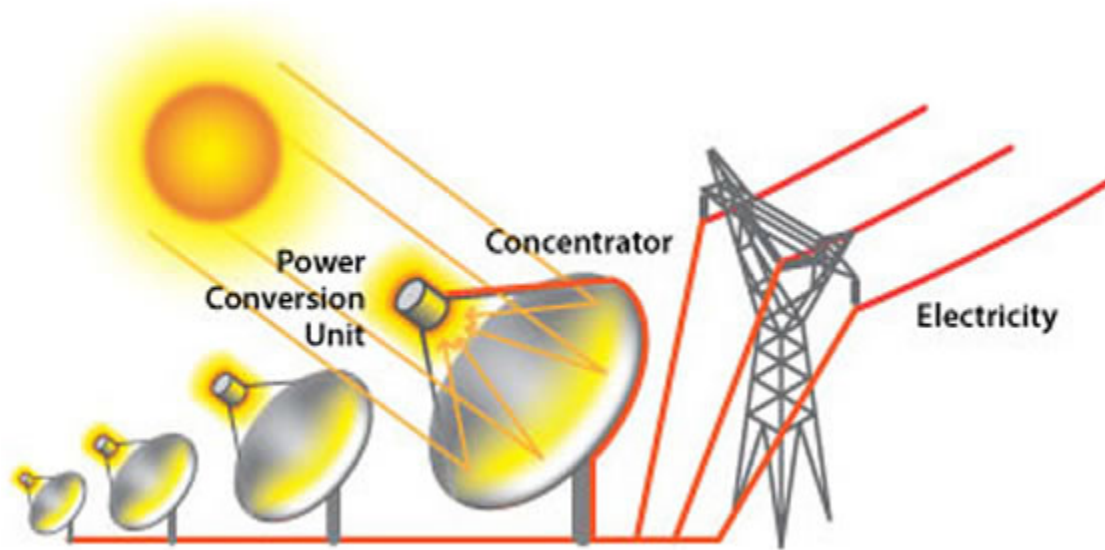


Figure 50 - Dish Stirling Solar Collector

This configuration does not use a steam turbine cycle as presented previously. From a theoretical standpoint, these systems can reach concentration ratios of greater than 1300x and working temperatures up to 1500°C [74, 75], but are still currently in the testing and development phases.

2.2.1.1.3. Geothermal Power

Geothermal power plants take in thermal energy from hot rock in the earth's crust to drive a steam turbine-based thermal plant, utilizing the temperature difference between the atmosphere and the hot rock. These power plants do not produce carbon dioxide or criteria pollutants since no fuel is being burned in operation. In order for a geothermal plant to produce a significant amount of power, it must be located in a region with the following characteristics:

- **Presence of a high temperature hot rock reservoir at a relatively shallow depth.** As discussed prior, the theoretical limit on the efficiency of a thermal plant depends on the temperature difference between the maximum and minimum temperatures within which the plant operates. The minimum temperature is generally fixed by the atmosphere. To

maximize the efficiency of the system, it is desirable to use hot rock that is at as high of a temperature as possible. The temperature of the earth's crust generally increases with depth but varies strongly with geography. Theoretically, if one was willing to drill deep enough, a hot rock reservoir of sufficient temperature could always be found. Practically, however, it is not economical to drill to extreme depths and construct the required piping and power plant systems to accommodate such depths. The temperature of a high quality reservoir for the purposes of geothermal power is considered to be about 200°C or higher.

- **Presence of an aquifer containing water or steam that can be accessed by drilling.**

Current geothermal technology uses water present in aquifers as the working fluid for the steam turbine cycle. In high temperature reservoirs, this water already exists as steam and is simply extracted into the power plant, used to drive the turbine cycle and discharged back into the aquifer. For lower temperature reservoirs, the water is used to heat an organic working fluid with a low boiling point that is used to drive the steam turbine cycle. In either case, the presence of water in an aquifer is necessary with current technology, since the movement of a fluid is able to transfer heat from the hot rock much more effectively than simple heat conduction. This aquifer must be continually recharged or at least maintain its water level.

These requirements tend to be met in regions where there is significant tectonic plate movement. These movements allow magma to flow at relatively shallow depths compared to other locations. California, being placed on the Pacific “ring of fire” has more access to high quality geothermal resources compared to much of the U.S. Using current technology, however, these requirements limit projections of geothermal power potential in the state to about 4,000 MW at a capacity

factor of 85 percent [76]. The majority of current geothermal resources are located north of San Francisco and east of San Diego.

There are also concerns regarding the over-extraction of geothermal heat. Geothermal heat originates from the decay of radioactive material in the Earth's core, and is transported by conduction to the crust. Conduction of heat is generally a slow process compared with convection of heat. The installation of too many geothermal power plants on a given heat reservoir can cause energy to be extracted from it at a rate faster than that which recharges it by conduction. This causes the temperature, and therefore quality, of the resource to drop over time. Additionally, since geothermal power is harnessed via steam-turbine based power plants, they have limited ramping and cycling capabilities and are operated as base-load power plants.

2.2.1.1.4. Biomass/Biogas Power

Biopower refers to power generated from feedstocks of plant matter or organic wastes. This includes but is not limited to trees, certain crops, grasses, human and animal wastes, sewage, agricultural wastes and municipal solid waste (assorted garbage). These feedstocks are typically sorted into two categories for electric power generation:

Biomass refers to solid feedstocks that are generally harvested, pulverized, and combusted in a steam-turbine thermal plant either by itself or along with coal. Biomass is typically collected from a variety of sources.

Biogas refers to gaseous fuels created from solid feedstocks that are generally combusted in a gas turbine thermal plant. This is typically accomplished via gasification or processing in an anaerobic digester to produce a methane or hydrogen rich gas stream. Biogas is typically produced at wastewater treatment plants or landfills as a byproduct.

The carbon content of biomass and biogas resources is much lower compared to fossil fuels such as coal. Additionally, since the feedstocks tend to originate from plants which have absorbed carbon dioxide from the atmosphere in order to grow, the combustion of biomass and biogas tends to have very low net carbon dioxide emissions. Many biomass types also exhibit reduced criteria pollutant emissions when burned. Some coal plants typically offset a part of their fuel stream with biomass to obtain carbon and pollutant emissions reductions in a process called co-firing. Since biomass and biogas are used primarily as a combustion fuel, the technology required to produce electricity from these resources is mostly the same as that used for conventional power plants.

Biopower resources exist in different forms in essentially every part of the U.S. California in particular uses a diverse range of biomass fuels including forest wastes, urban wood wastes, agricultural wastes, municipal solid waste and biogas.

The diversity of biomass sources, however, represents its biggest strength but also its biggest disadvantage. Different types of biomass can have vastly different combustion properties depending on their particular composition and moisture content. Some types can require extensive processing before being suitable to use as a fuel. Most biomass types also have lower energy densities compared to fossil fuels, requiring a larger feedstock to produce the same amount of thermal energy when burned. This is compounded by the fact that biomass sources are typically distributed and energy is required to harvest, collect, and transport sufficient quantities of these feedstocks for processing and use. The availability of agriculture-based biomass feedstocks and therefore the power output of the associated plants also vary seasonally with growing patterns.

For example, consider the use of “energy crops”, which are crops that are grown for the purpose of being harvested and burned in a power plant to produce electricity. This process, however, requires resources for harvesting and transportation due to the low energy density and large land area required to produce a sufficient amount of biomass.

Additionally, the use of certain types of biomass can have potential environmental issues. The use of farm land for growing energy crops competes with the use of the same land for growing food crops. Overuse of farm land for growing energy crops can also stress the land itself, hampering its future ability to grow crops of any kind. For the use of natural biomass feedstocks such as forest wood, harvesting too much can accelerate deforestation.

In terms of power plant operation type, biomass power plants typically operate in a base-load fashion. Most biomass types are used in steam-turbine thermal plants along with coal or by itself, and are subject to the same operating limitations. Biogas power plants can operate in either a base-load, load following or peaking configuration due to biogas being able to be used in gas turbine thermal plants, but are also typically used in base-load operating schemes.

These issues have limited biopower utilization for electric energy in California to about 985 MW in 2007 [37], serving 1.85 percent of the energy of the load demand during that year [77].

2.2.1.1.5. Hydropower

Conventional, large hydropower plants utilize existing streams and gravitational potential energy from a height difference to produce electric power. These power plants are very favorable from a system operator perspective, since the high flexibility, large capacity and low cost allows them to fulfill many critical roles in supporting the electric power system. For example, hydropower provided 80 percent of the spinning reserve capacity for California in the year 2000 [50]. Due to

the nature of these plants, however, there are limitations on where they can be constructed.

Hydropower is only available at locations where there are large volumes of water flow, and the larger plants can only be constructed where a significant height difference can be created.

Additionally, the siting of hydropower plants is limited by land use and ecological concerns.

In California, about 14,000 MW of hydropower dependable capacity is installed. **Dependable capacity** refers to the maximum power output that the entire hydropower fleet can produce on command. The actual contribution of hydropower to serving the energy of the load demand depends strongly on the operation of this fleet from year to year. The stream flows that drive hydropower plants originate as rainfall or the melting of snowpacks in two primary areas: 1) the Sierra Nevada mountain range in the eastern part of the state, and 2) the Cascade mountain range that expands through Oregon and Washington. As rainfall and temperature patterns in these regions differ from year to year, the amount of water available for hydropower production also varies from year to year. Drought years will exhibit lower energy contributions and vice versa for years with heavy precipitation. Therefore, the capacity factor of the aggregate hydropower fleet varies from year to year, and dependable capacity may not give a complete picture. For example, the capacity factor for hydropower generation in 2005 was about 32.8 percent, compared to 22.1 percent in 2007 [77, 78], with the same installed capacity.

California has a large hydropower potential compared to the majority of other states in the U.S. Based on pure stream flow, the state has a total potential annual mean capacity of 27,000 MW. The annual mean capacity refers to the effective capacity of the hydropower fleet if it had a capacity factor of 100 percent. The available potential for hydropower, however, is substantially lower since about 12,000 MW of that capacity would require development on federally protected

lands. This leaves the usable hydropower potential to be about 15,000 MW on an annual mean power basis, which is still a large energy contribution [79]. The annual mean power of the current hydroelectric fleet is approximately $1/3^{\text{rd}}$ of the nameplate capacity, or about 4,700 MW.

While there is a large potential for hydropower development, the growth of hydropower has been essentially stagnant in recent decades. The nameplate hydropower capacity in California has only increased by 100 MW since 1999 [80]. The utilization of the state's hydropower potential is highly limited by the potential ecological and water resource impacts of hydropower plants. Since these installations disrupt natural river flows, they can damage wildlife and ecosystems that develop in these rivers and interfere with water resource needs. For example, the water at the bottom of a hydropower plant is generally colder and lower in oxygen content, killing fish that live downstream of the plant. Plants with large reservoirs tend to withhold water and release it in short bursts, contributing to flood concerns. Due to effects such as these and other similar effects, very few hydropower plants can be permitted.

From the perspective of the renewable portfolio standard, these concerns have led to only "small" hydropower to be counted as renewable. Small hydropower refers to plants with a capacity of less than 30 MW. These plants typically involve power plants that do not have reservoirs and do not interfere significantly with natural river flows as much as large hydropower plants. The power output of these plants is not controllable in the same sense as 'large' hydropower, however, and varies directly with stream flow. When only these installations are considered, the potential capacity of RPS-eligible hydropower is 2,182 MW at a capacity factor of 36.7 percent [65].

Hydropower is a very valuable renewable resource with a large technical development potential. The ability to utilize that potential, however, is extremely limited due to the impacts that these installations can have on their surrounding environments and water resources. Consequently, the potential of hydropower resources that are small enough to not have potentially detrimental effects on local ecology and water resources is very small.

2.2.1.2. Complementary Technologies

2.2.1.2.1. Energy Storage

Another supporting technology that can aid the electric power system with the integration of variable renewable power is energy storage. In general, ‘energy storage’ as a category refers to technologies that are able to store energy produced by a primary generation resource and discharge said energy to a component of the electric power system at a different time. Many technologies currently exist that can perform this function, and each technology has different characteristics that make them suitable for serving different roles in the electric power system. This section seeks to give an overview of some types of energy storage and discuss their effectiveness in terms aiding the integration of variable renewable power. This particular section focuses on electric energy storage: that is, energy storage systems that store and discharge electric energy. Other types of energy storage which primarily store and discharge cold or hot water for cooling or heating loads respectively are not discussed in this dissertation.

2.2.1.2.1.1. Types of Electric Energy Storage

Electric energy from a primary generation resource can be stored using a variety of mechanical, chemical, and electrochemical methods. A brief overview of some of the characteristics of the major technologies is discussed here. Further detail on energy storage technologies can be found in [52, 81-83].

Pumped Hydropower Storage (PHS). Pumped hydropower storage systems utilize two water reservoirs at different heights as an addition to a balancing hydropower plant. To store energy, electric energy obtained from power plants is consumed to pump water from the lower reservoir to the higher reservoir, converting electric energy to gravitational potential energy. To discharge energy, water from the higher reservoir is released through liquid turbines, converting the gravitational potential energy into electric energy. The released water ends up in the lower reservoir.

PHS occupies a unique place within the suite of energy storage technologies since it is the only technology which is capable of both high power charge/discharge rates and the storage of large amounts of energy [81-83] per system. Since PHS systems are constructed as additional capability to balancing hydropower plants, these systems are very large in scale. PHS systems are also able to change charge/discharge rates very quickly due to simple operating principles and proven technology. The response time of PHS systems is essentially the same as balancing hydropower plants, which are typically used for load-following purposes at current. These systems also exhibit reasonably high round-trip efficiencies between 75-85 percent since the primary losses are only due to inefficiencies in pumping equipment [81]. PHS systems are also able to endure many cycles and last for many years.

The potential use of PHS systems, however, is limited by the same factors which limit the use of balancing hydropower systems as discussed in Section 2.2.1.1.5. Impacts on the local environment in terms of ecology and water resources constrain any rapid development of PHS systems. The conversion of balancing hydropower capacity to a PHS system is also complicated

by the fact that lower reservoirs of sufficient size do not exist near many facilities and would need to be constructed in whole.

Compressed Air Energy Storage (CAES). Compressed air energy storage systems utilize a large reservoir such as an underground cave to store high pressure compressed air. To store energy, electric energy obtained from power plants is used to take in and compress ambient air. To discharge energy, this compressed air is combusted with fuel such as natural gas and is expanded through a series of turbines to produce electric energy. Overall, CAES systems are simple cycle gas-turbine power plants which decouple the compression and expansion steps from each other.

CAES is also a technology which is capable of relatively high power charge/discharge rates and the storage of relatively high amounts of energy, although typically not as high as PHS systems. These systems typically have a discharge power capacity between 5 to 300 MW with rated discharge times from 1 hour to upwards of 24 hours [81]. Note that since the compressor and turbine are decoupled, the charge and discharge power rates can be different. The energy capacity of a CAES system is dependent on the size of the reservoir, which can vary by location. Reservoir types include depleted aquifers, salt caverns, and other underground cavern formations. The power capacity of a CAES system depends on the sizing of the gas turbine components.

CAES systems are different from other energy storage technologies in that it requires additional energy input in the form of fuel to operate. This requirement renders these systems to have relatively low round trip efficiencies once the fuel input is taken into account, on the order of 41-55 percent [84]. These systems also have criteria pollutant and greenhouse gas emissions which

may partially mitigate the benefit of storing and discharging energy from variable renewable resources. The response time of a CAES power plant is similar to a simple cycle gas turbine of 5-10 minutes.

Currently, only two CAES systems are in operation worldwide. A system in Huntorf, Germany operates with a discharge power capacity of 290 MW, a charge power capacity of 60 MW, a rated discharge time of up to 3 hours and an efficiency of 42 percent. Another system in Alabama operates with a discharge power capacity of 110 MW, a rated discharge time of 24.5 hours (2700 MWh) and an efficiency of 55 percent [52, 85].

Flow Batteries. Flow batteries are devices which utilize liquid electrolyte to store energy. To store energy, an oxidation-reduction reaction converts electric energy to chemical energy in the electrolyte species. To discharge energy, charged electrolyte is introduced to the electrochemical cell and the same oxidation-reduction reaction occurs in the reverse direction. Different oxidation-reduction reaction chemistries can be used such as vanadium or zinc-bromide. Flow batteries differ from conventional batteries in that the electrolyte is stored separately from the electrochemical cell, whereas in conventional batteries these two components are stacked together.

Flow batteries are able to store larger amounts of energy compared to conventional batteries, and operate at similar power levels [83], up to 10 MW and 10 hours of rated discharge per system [81]. The power and energy capacities of these systems are smaller overall compared to PHS and CAES systems [81]. The advantage of these systems, however, is the external storage of the electrolyte allows the energy and power capacity of these systems to be sized independently of each other. The energy capacity is determined by the amount of electrolyte stored, whereas the

power capacity is determined by the active area of the electrochemical cell. Flow batteries are also projected to be able to endure many more cycles (12000+) compared to conventional batteries [81]. Round trip efficiencies for these systems range from 65-80 percent depending on chemistry [81, 86].

Flow batteries have not yet been widely deployed for energy storage applications; therefore field experience with these systems is lacking [52]. Some limitations for the use of flow batteries include costs due to the use of exotic materials, large physical footprint due to the storage of large amounts of electrolyte, and the toxicity of the electrolyte [81, 86].

Conventional Batteries. Conventional batteries also use electrochemical cells and charged electrolyte to store and discharge energy. In these systems, the electrolyte can be solid or liquid, and is installed as a part of the electrochemical cell assembly. These cells are stacked together to produce the desired voltage. Within each of these cells, reversible reactions take place which convert chemical energy to electric energy or vice versa. Conventional batteries can be constructed using a very diverse suite of chemistries, each with their own advantages and disadvantages. Details on these different chemistries are outlined by EPRI [86], the CEC [52], and work by Chen [81].

Conventional batteries are typically unable to store large amounts of energy, but are capable of reaching high power capacities for both charging and discharging modes. Batteries can also have very high round trip efficiencies depending on chemistry. Efficiencies for conventional batteries can be as low as 75 percent for NaS chemistry up to as high as 92 percent for Li-ion chemistry [86]. These systems are also capable of responding and ramping much quicker than most of the other electric energy storage technologies.

A number of factors, however, are present which limit the use of conventional battery technology in electric power system applications. Conventional batteries typically have higher costs compared to other energy storage technologies on a levelized basis, due to the use of exotic materials and manufacturing, as well as low energy densities. The lifetime of these systems tends to be relatively short compared to other technologies, and significant degradation in power and energy capacity occurs as a battery undergoes more power cycles or is discharged to low levels.

Flywheels. A flywheel is a device which uses a spinning mass to store energy in kinetic form. To store energy, electric energy is used in an electric induction motor which accelerates the spinning mass to high speeds. To discharge energy, the spinning mass is used to operate the electric motor in reverse as a generator to convert the kinetic energy back to electric energy. Flywheels are typically suspended in vacuum enclosures with magnetic bearings, and spin up to 50,000 rpm [52].

Flywheels share an operational characteristic with batteries in that these devices have high power capacities but low energy capacities. Large flywheels can have power capacities up to 1 MW and rated discharge times of up to 1 hour, and adding multiple flywheels in tandem can increase system capability. These systems have response times on the order of milliseconds and high round trip efficiencies on the order of 90-95 percent. Additionally, these systems are able to withstand many charge/discharge cycles (20000+) and be in operation for 15-20 years [81, 86].

Flywheel energy storage is a relatively mature technology that is used for uninterruptible power supply applications in commercial industries. The limited energy capacity of these systems, however, limits the applicability of this technology at current.

A summary of the relative discharge power and energy capacities of these different methods is presented as follows [87]:

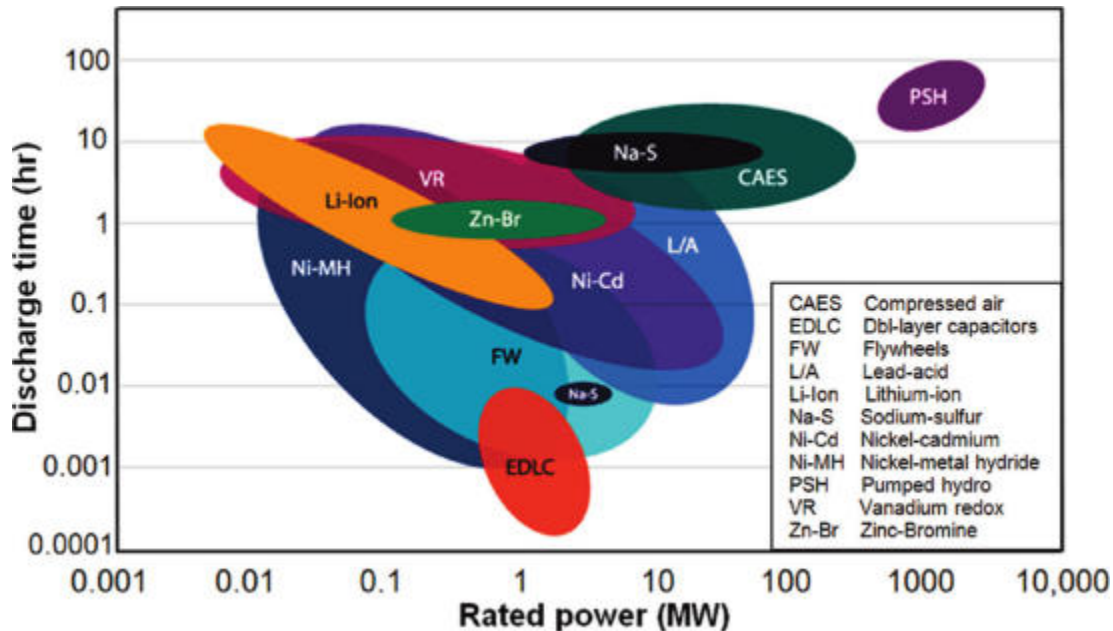


Figure 51 - Rated Discharge Time and Power Capacity Ranges for Different Energy Storage Technologies [87]

Overall, a number of different methods exist for storing and discharging electric energy. The characteristics of these different methods enable them to be suited for different applications in aiding the electric power system with integrating variable renewable power.

2.2.1.2.1.2. Potential Applications for Aiding Variable Renewable Integration

The implementation of energy storage systems in the electric power system has the potential to mitigate many of the potential issues regarding the integration of renewable resources. The ability to store and discharge energy to meet the net load demand can decouple the behavior of electric power generation from that of the load demand. This can allow certain parts of the electric power system to be more resilient to the impacts of variable renewable power. Some of the major applications for different types of energy storage systems in this respect are discussed

here. Note that the applications for energy storage listed here is by no means comprehensive of all possible uses for these technologies. More applications of energy storage on the electric power system are discussed by EPRI [86].

Provision of Regulation Capacity. As discussed previously, regulation capacity is used to compensate for unpredictable short-term variation in the net load profile. Balancing power plants provide this service by continually increasing or decreasing their power output in minute-to-minute intervals to keep the system balanced and the grid frequency within bounds. Energy storage systems could potentially fill this role to some extent in the future. Fast-responding energy storage types can charge to provide regulation-down capacity and discharge to provide regulation-up capacity and be dispatched at the command of the balancing authority similar to balancing power plants. The depth of discharge limits on different energy storage types could be treated in the same manner as the minimum part-load operating condition of balancing power plants.

The use of energy storage may be capable of reducing the capacity of balancing power plants that must be committed to provide regulation capacity, which is expected to grow with increased renewable capacities on the electric power system. This can also reduce the ramping and cycling burden of balancing power plants with by allowing these units to be primarily focused on meeting long-term net load variations. Many energy storage types are also capable of responding much faster than balancing power plants in terms of power ramping.

The provision of regulation capacity requires fast-ramping capability and high power capacities more than high energy capacities. Since regulation deals with short-term variations in the net load that are typically smaller than long-term variations even with variable renewable power,

regulation services do not require a large amount of energy to be dispatched. This application is then suitable for energy storage types such as flywheels and balancing batteries which have these characteristics [52].

Provision of Spinning Reserve Capacity. Energy storage can potentially be used to provide spinning reserve capacity and allow balancing power plants to have additional operational flexibility. The benefits for the electric power system with variable renewable power are the same as that when demand response is used to provide spinning reserve capacity. For example, after a contingency event, a fully-charged energy storage system could be dispatched to discharge and temporarily restore the grid frequency for a long enough period until other generation can be brought online. Since many energy storage systems respond quicker than balancing power plants, this application can be well suited to certain types of storage. The energy capacity requirement to perform the spinning reserve function is moderate, as the system must be capable of providing its full power capacity for at least 2 hours for current CAISO standards. This renders pumped hydropower, compressed air, flow batteries, and large balancing batteries suitable to perform this function.

Many energy storage systems have a self-discharge characteristic, however, where the system loses a small fraction of the energy that is stored is lost over time. Depending on the frequency of contingency events, energy storage systems providing spinning reserve may not be utilized very often and may need to continually be recharged.

Bulk Energy Management. Energy storage can also be used in a variety of ways to shape the net load profile and bestow characteristics that ease the burden on balancing power plants. This can be especially valuable at high renewable penetration levels, where the net load profile has

characteristics that current power plants are not completely equipped to meet. The use of energy storage in this application can entail any of the following:

- Reducing over-generation. During periods when renewable power generation becomes high enough to require curtailment due to inability to shut down committed base-load power plants or insufficient load, energy storage systems can absorb the associated excess energy for use at a later time when renewable power is low. This allows higher utilization of variable renewable resources and can delay the occurrence of the point of diminishing returns and its associated implications to higher renewable penetration levels.
- Smoothing the effects of variable renewable power generation. The peak-dominated nature of wind and solar power combined with potentially strong short-term variability poses challenges for the electric power system. Energy storage systems could potentially decouple the behavior of wind and solar power production from the power output that is placed onto the electric power system. For example, consider when the quick ramping down of solar power combined with the load demand increase in the early evening will require balancing power plants to ramp up too quickly or that a peaker plant be brought online. If energy storage was installed on the system, CAISO could dispatch it to discharge and slow the increase in net load such that committed load-following power plants have sufficient time to ramp up and prevent the activation of a peaker. The opposite could be performed due to a net load decrease for the purpose of preventing a balancing power plant from having to shut down or operate at severe part-load conditions. Additionally, energy storage could allow variable renewable power plants to

have some degree of dispatchability. By decoupling wind and solar behavior from the power output to the system, a wind or solar power plant could potentially be scheduled into the CAISO day-ahead forecast in a manner similar to a balancing power plant. This would require, however, that sufficient energy be present in the energy storage system to firm or guarantee the scheduled production. For solar power plants, if an energy storage system and solar capacity was sufficiently large, the duration of power output from that plant could be extended into the nighttime hours.

- Shaping of the net-load profile. Energy storage could also be used to shape the net load profile and give it characteristics that are more preferable for balancing power plants. For example, wind and solar power in California do not significantly reduce the daily peak net load. Energy storage systems could potentially be dispatched to address this issue. Energy from renewable power plants (and non-renewable power plants if the former is not sufficient) can be stored from other periods of the day and discharged when the net load is high to level the peak. The opposite can be done to raise the minimum net load value which decreases at higher renewable penetration levels. Energy storage systems could be dispatched to charge during periods of very low load and allow balancing power plants to remain online with more steady operation for longer periods of time. By reducing the daily range of the net load, the capacity factor of the balancing power plant can be increased.

All of these functions require fairly large amounts of energy to be shifted from one time of the day to another, and may possibly require shifting of energy over longer timescales. Therefore, only energy storage types which have the ability to store large amounts of energy can be

considered. Additionally, depending on the function, high power capacities may also be required to complement variable renewable power behavior. With current technologies, this limits bulk energy management to pumped hydropower, compressed air, and large flow battery energy storage systems [52, 88].

Congestion Relief on Transmission and Distribution Lines. Energy storage systems can potentially provide support for the transmission and distribution network by being dispatched to alleviate power flow and voltage stability problems. Substantial additions to transmission and distribution line capacities may be required to readily integrate high capacities of variable renewable power in California. Additionally, voltage stability issues may be encountered with increased variable renewable penetration, requiring transmission system upgrades. Energy storage could potentially defer some of the capacity upgrades to existing transmission lines and manage the power flow patterns caused by variable renewable power behavior.

Consider a transmission line connected to a substation that is operating near one of its power flow limits due to a high load at the substation. If an energy storage system was placed at the substation, it could discharge energy to the substation and displace the real power that is flowing through the transmission line. This raises the voltage at the end of the transmission line and reduces the amount of power flowing through the line. When the load at the substation decreases and high power flow will no longer be required, the energy storage system will draw power from the electric power system via the transmission line to be ready for the next high-congestion period [89].

By extension, the temporary injection or extraction of real power into receiving or transmitting ends of a transmission line could potentially be used to manage voltage and power flow. The

extent to which this is desirable is unclear, given that proven reactive power compensation methods that are already employed.

To perform this function, the energy storage system must have a power capacity that is high enough to displace a significant portion of the transmission line's power flow and an energy capacity that is high enough to sustain that power for the duration of the high-congestion period. Since these systems are sited at substations or near load centers, geographically constrained types such as pumped hydropower and compressed air energy storage cannot perform this function. All other types that can be sited near load centers could potentially perform this function. The most suitable type will depend on the specific line and load being served.

Overall, there are many potential applications for energy storage to aid the electric power system with the integration of variable renewable power. The extent to which it is feasible for energy storage systems to be used in these applications from both a technical and economic standpoint is currently a subject of ongoing research.

2.2.1.2.2. Demand Response

Another potential solution for helping to integrate renewable resources into the electric grid is demand response. **Demand response** refers to the ability to manage the behavior of the load demand due to different end uses to respond to the behavior of variable renewable power generation. The dispatch of controllable loads relies on communication which allows end-users or building control systems to monitor the behavior of the net load on the electric power system. Demand response is used to modify the load demand profile to reduce the burden on the electric power system during events caused by renewable power behavior or otherwise. This section seeks to give an overview of some types of demand response and discuss the effectiveness of their implementation in terms of aiding the integration of variable renewable power.

It is important to distinguish demand response from **energy efficiency** measures. Energy efficiency refers to static control of load types to reduce total energy use. Demand response refers to dynamic dispatching of load types. Power reduction measures that continually minimize energy consumption all the time without affecting occupant preferences are energy efficiency measures. On the other hand, power reduction measures which actively respond to minimize load when needed refers to demand response. The difference is that energy efficiency refers to passive load reduction measures that are always operating. Demand response refers to active load reduction measures that only operate when needed, but cannot operate all the time since it will violate user preferences (i.e. comfort).

2.2.1.2.2.1. Types of Demand Response

Electric energy is consumed for a large variety of end uses, and only some of the associated loads can be controlled. Theoretically, all controllable loads could provide demand response. Certain types of loads are more common amongst residential, industrial, and commercial sectors, however, and form larger portions of the aggregate load demand. The ability to dispatch or reduce these loads dynamically is the focus of demand response. Some examples of these load types and their dispatch is discussed here.

1. **Lighting reduction.** Commercial, industrial, and residential load sectors require illumination to operate, but many buildings are currently illuminated to levels that are higher than necessary to perform required tasks. Therefore, lights within buildings can be dimmed to reduce the lighting load in response to an event occurring on the electric power system. For example, consider a case where renewable power generation decreases by a large amount in a short period of time. In response to this event, lights can be dimmed to reduce the load demand such that balancing power plants do not have to

ramp up as quickly. The extent to which the dimming of lights can be carried out is limited by occupant comfort. The lighting inside a building can only be dimmed up to the point where occupants begin to notice and the reduction affects their ability to perform their tasks. The maximum reduction is different from building to building, depending on factors such as the amount of day-lighting in the space and the rate of lighting reduction with slow rates being preferable [90]. Results for commercial buildings in Southern California show that lighting reduction can reduce annual energy consumption by 5-20 percent depending on the extent allowable [43].

2. **Global Temperature Adjustment (GTA).** This strategy involves the adjustment of temperature set-points in a building for heating and cooling to reduce the associated loads. When a cooling set-point is raised to a higher temperature, the equipment associated with meeting or maintaining that set-point can operate at reduced power consumption. For example, consider a building where the cooling set-point is raised from 72°F to 76°F. In this case, chillers can reduce cooling output and air distribution equipment can reduce power consumption, since the cooling demand associated with meeting the higher set-point is decreased. A similar concept occurs for decreasing the heating set-point. The pumping of hot water and air handling equipment can operate at reduced power consumption since the heating demand that is associated with meeting the new set point is decreased. GTA can be accomplished either by an automated building control system or by manual operation. This strategy has been found to be one of the most effective in reducing power consumption since it affects almost all of the HVAC components at the same time [91]. The effect on occupant comfort which limits the

extent to which set points can be changed can vary since some occupants will be more comfortable in a given temperature range than others.

3. **Duct Static Pressure Reduction and Ventilation Fan Turndown.** The duct static pressure and ventilation fan speed determine the supply of airflow for ventilation purposes in buildings. In response to an event on the electric power system, the set-point for the duct static pressure can be reduced and the speed of the ventilation fan can be limited to a certain percentage of its rated speed, reducing the air handling load. The maximum allowable power reduction is dependent on occupant comfort and the design ventilation rates for the building.
4. **Pre-cooling.** Pre-cooling refers to using the thermal mass of a building to shift the cooling load. This involves cooling the building to a low temperature prior to the occurrence of the peak load period, then allowing the building temperature to rise for the duration of the peak load period. The cooling load is effectively shifted from the time of peak load demand to times slightly before the occurrence of peak load demand. The thermal mass of the building determines the rate of temperature reset and the duration for which cooling load can be removed. Results from LBNL [92] indicate that a large commercial building in California can reduce its peak power consumption by up to 20-25 percent when utilizing pre-cooling.

These types only refer to a few of the major demand response strategies that can be implemented in many different building types. A more comprehensive list of controllable loads and their dispatch is discussed by [91].

2.2.1.2.2.2. Potential Applications for Aiding Variable Renewable Integration

The control and dispatch of certain loads to shape the aggregate load demand profile and therefore the net load profile can be applied in a variety of ways to mitigate some of the issues regarding the integration of renewable resources.

Controlling loads can potentially have some of the same effects as controlling power plants to respond to the behavior of variable renewable power. For example, keeping the system balanced during a drop in wind power can either be accomplished by an increase in balancing power plant output or actively reducing the load demand via demand response. Certain types of controllable loads are able to respond much faster than balancing power plants, which make them ideal for serving certain roles in the electric power system.

With this in mind, some of the potential applications for demand response are as follows.

Further detail on these applications can be found in work by ORNL and LBNL [59, 92].

- **Peak-Shaving.** This refers to the use of demand response to reduce the daily peak of the net load demand by removing load during these times. For renewable penetration levels that are likely to be attained in the near-to-midterm in California, pre-cooling is well suited to providing peak-shaving capability. Since the penetration of variable renewable power is low, the peak net load demand tends to align with the hottest periods of the day and pre-cooling can serve to reduce the load during these times. Other demand response strategies are also applicable. **The limitation for demand response to perform peak shaving is the inability for many demand response strategies to sustain a response for the duration of the entire peak-load period.** In terms of complementing variable renewable power, this can provide an important benefit, since wind and solar power in California does not tend to reduce the magnitude of the daily net load peak by a

significant amount. This requires large capacities of balancing power plants to still be online on a given day to meet this net load. With demand response, different strategies can be used to reduce the daily peak net load. This can allow a lower capacity of balancing power plants to be online for the same energy contribution, increasing the capacity factor of the power plant fleet. Additionally, variable renewable power can also cause the duration of the net load peak to last for a shorter time period at high renewable penetration levels. This suits the characteristic of demand response being unable to provide long-term responses, and can prevent the startup and use of peaking power plants to meet this short duration load peak. A reduction in peaking power can contribute to increased fleet-wide capacity factors, and fuel use and emissions reductions.

- **Provision of Contingency Reserve Capacity.** Contingency reserve capacity is backup capacity that can be called upon to provide power in order to keep the system balanced after a contingency event. When this capacity is called upon, balancing power plants with spinning reserve awards increase their power output to provide balancing power. This response can be replicated by the reduction of load after a contingency using demand response. The requirements for providing spinning reserve capacity in particular are well suited for demand response. Many types of loads can be decreased in magnitude or shut off very quickly and do not have the same ramping or minimum on-time limitations of most balancing power plants. The primary delay in utilizing demand response is the delay in communication between system operators and building management systems or end users. With automated systems, this can occur very quickly. Using demand response to perform this function can also provide important benefits for supporting variable renewable power. By allowing demand response to provide

contingency reserve capacity, more capacity for load-following becomes available in the balancing power plants that are online. This can increase the operating range of balancing power plants. For example, consider a power plant with an operating range bounded between 50 and 90 percent of rated capacity. The lower bound is set due to emissions limits and the higher bound is set since this power plant commits 10 percent of its capacity to spinning reserve. If demand response is able to displace that 10 percent of extra capacity, the power plant can operate between 50 and 100 percent. A larger operating range allows this power plant to operate closer to design specifications for increased efficiency and reduced emissions. Additionally, a larger operating range may reduce the number of shut-down (and subsequently start-up) events that balancing power plants may have to endure. Balancing power plants may be able to perform their typical load-following function in a higher part-load range, decreasing the probability that it will operate close to its minimum power or be required to shut down.

- **Regulation-Up Capacity.** Since many load types can respond very quickly in terms of decreasing their demand, demand response can potentially be used to provide regulation-up capacity. Regulation-up capacity is required to balance net-load decreases that occur on short-timescales. Instead of increasing the power output of balancing power plants, load reductions from demand response can be used on a continuous basis. The primary limitation on performing this function is that only a few load types can be cycled continuously without violating occupant preferences. Industrial loads such as gas and water pumping or solid-state loads which can be varied continuously and within a small range can potentially fit this application.

- **Energy Consumption Reduction.** Demand response measures could be used on a recurring basis to reduce the bulk energy consumption of the system. For example, the temperature in a building can be adjusted in real-time every day to meet an energy consumption target. This application is more similar to an energy efficiency measure which seeks the same goal. The primary difference between this application and pure energy efficiency measures is that this entails the use of active means to reduce energy consumption.

Overall, demand response has the potential ability to ease some of the burdens of responding to variable renewable power behavior for the electric power system. The extent to which demand response could garner these benefits is a subject of current research. Limitations on the use of demand response will be discussed in a later section.

2.2.2. Light-Duty Transportation Sector

2.2.2.1. Plug-in Electric Vehicles (PHEVs + BEVs)

One of the major ways to meet the transportation demand with reduced greenhouse gas and criteria pollutant emissions is through the use of plug-in electric vehicles or PEVs. This class of vehicles refers to those which ‘plug’ into the electric power system to charge a battery that is used for primary or secondary propulsion. Currently, there are three major types of plug-in electric vehicles that are on the market in California. A brief overview of each type is presented here:

2.2.2.1.1. Vehicle Characteristics

2.2.2.1.1.1. Battery Electric Vehicle (BEV)

A BEV is a vehicle that uses electric energy as the only fuel for propulsion. The drivetrain of these vehicles consists of a large battery connected to either an AC or DC electric motor used to

drive the wheels. After the battery is depleted, these vehicles are plugged into either a 120 V or 240 V outlet on the distribution system at a house, workplace, or other connection point to recharge.

From a vehicle usage standpoint, battery electric vehicles have significant environmental benefits. Since no fossil fuels are burned while in use, BEVs emit no greenhouse gases or criteria pollutants. The efficiency of the electric drivetrain also tends to be much higher than that of a conventional internal combustion engine-based drivetrain, indicating reduced energy requirements to meet the same VMT demand. The main environmental impacts of BEVs are due to the additional demand that their usage imposes on balancing power plants in the electric power system. The electric power system, however, is typically more adept at managing criteria pollutant emissions than mobile sources such as vehicles due to the larger scale of balancing power plants allowing the use of extensive exhaust cleanup equipment.

Within the transportation sector alone, however, BEVs are subject to a number of limitations. A primary limitation for BEVs is driving range. Current battery technology is only able to produce batteries with a relatively low energy density on both volume and mass bases compared to conventional liquid fuels. The increase in efficiency through the use of an electric drivetrain is more than offset by the reduced amount of energy that can be carried onboard the vehicle. For example, the energy density of state of the art lithium-ion batteries is about 200 Wh/kg [93]. For comparison, the energy density of gasoline is about 12,000 Wh/kg, about 60-120 times that of lithium-ion batteries.

While electric drivetrains tend to be on the order of 6 times more efficient than conventional drivetrains, large battery capacities are still required to obtain reasonable driving ranges. For

example, an 18-gallon gasoline tank carries about 110 pounds of gasoline. For a vehicle with an average fuel economy of 25 miles per gallon, this equates to 450 miles. The Nissan Leaf, which is a BEV that is currently sold on the market, uses a 24 kWh battery pack that weighs approximately 660 pounds [94] for a range of 100 miles [37]. This causes BEVs to typically be much heavier than their conventional counterparts with current battery technology.

Another primary limitation is the charging time. Distribution lines and low-voltage systems are not designed to sustain power flows to each customer equivalent to that of gasoline flowing through a pump. The result is that BEVs require long periods of time to charge to full capacity. For example, the Nissan Leaf requires about 7 hours to charge from empty to full capacity when plugged into a 240V outlet [37], compared to a conventional vehicle which requires 5 minutes to fill a gasoline tank at a fueling station.

To overcome these limitations, battery technology needs to be improved and distribution infrastructures need to be upgraded to retain the current paradigm of vehicle usage.

Alternatively, the paradigm of vehicle usage will need to change to accommodate this technology.

2.2.2.1.1.2. Series Plug-in Hybrid Electric Vehicle (S-PHEV)

This refers to a vehicle that utilizes both gasoline and electric energy as the fuels for propulsion, but allows the wheels to be driven only by the electric motor. The drivetrain consists of a battery that drives an electric motor and a gasoline engine that activates to charge the battery when it is depleted while the vehicle is in motion. The gasoline engine is not connected to the wheels and is only a supplement to the electric motor. The battery can also be recharged by connecting it to a 120 V or 240 V outlet. In typical operation, the vehicle can operate on battery power alone up to a certain distance called the “all-electric range”. Beyond that distance range, the gasoline

engine is activated. The decoupling of the gasoline engine from the wheels allows it to operate at its most efficient speed since it does not have to follow variations in vehicle speed.

From the standpoint of vehicle usage, these vehicles offer significantly reduced greenhouse gas and criteria pollutant emissions compared to conventional gasoline vehicles. Ideally, if a consumer's trips were always shorter than the all-electric range and the vehicle was fully charged from the electric power system between such trips, this vehicle could theoretically never use any gasoline. In practice, consumer trips tend to exceed the all-electric range and full charges are not always possible between every trip. Since the majority of driving trips tend to be short in distance, however, these trips are met in electric vehicle mode and have reduced gasoline consumption if the battery was charged by the electric power system.

The environmental benefits due to usage of these vehicles are not as extensive as that of battery electric vehicles since the use of a gasoline engine still creates greenhouse gas and criteria pollutant emissions. Consequently, these vehicles also are not as restricted by the limitations of battery electric vehicles. The inclusion of a gasoline engine eliminates the range limitation problem. Additionally, the battery can be downsized compared to a BEV since it is not expected to carry enough energy for a very long driving range, and the all-electric range of series plug-in hybrids is typically smaller than the range of a BEV. The use of a smaller battery allows charging times to be shorter than that of a BEV with the tradeoff of a lower all-electric range. For example, the Chevrolet Volt uses a 16 kWh battery to provide 40 miles of all-electric range. The battery can be charged in 4 hours using a 240 V outlet [77].

The use of two powertrains, however, causes these vehicles to still be substantially heavier than their conventional gasoline counterparts. For example, the Chevrolet Volt has a curb weight of

about 3,781 pounds but is classified as a compact car according to the U.S. Environmental Protection Agency's automobile size classification. For comparison, a 2012 model year Honda Civic, which is a standard compact car, has a curb weight of approximately 2,800 pounds.

2.2.2.1.1.3. Parallel Plug-in Hybrid Electric Vehicle (P-PHEV)

This also refers to a vehicle that uses both gasoline and electric energy as the fuels for propulsion, but allows the wheels to be driven by both the gasoline engine and electric motor. The drivetrain consists of the same components as the series plug-in hybrid. With this configuration, the gasoline engine is mechanically connected to the drive wheels. In contrast to the series plug-in hybrid, however, the gasoline engine may activate even when the battery is not depleted. Conditions that require increased power output such as driving uphill or quick acceleration will activate the gasoline engine. In the same manner as the other PEV types, the battery can be charged by connecting it to a 120 V or 240 V outlet.

From the standpoint of vehicle usage, these vehicles offer slightly reduced greenhouse gas and criteria pollutant emissions compared to conventional gasoline vehicles. These vehicles tend to have smaller battery sizes than both of the other PEV types since the gasoline engine is used more often. This causes the all-electric range of these vehicles to typically be much smaller than the series configuration or the BEV. For example, the Toyota Prius Plug-in hybrid which uses this configuration has an all-electric range of 11 miles [95]. The increased reliance on the gasoline engine results in greenhouse gas and criteria pollutant emissions that are higher than the other PEV types but lower than conventional gasoline vehicles.

The smaller battery size also allows shorter charging times. The battery of the Toyota Prius Plug-in hybrid can be charged in 1.5 hours from a 240 V outlet.

Overall, there are currently three different types of plug-in electric vehicles. Each type has advantages and disadvantages in terms of their use for meeting the transportation demand and consumer preferences. Each of these types will rely on the electric power system to differing extents depending on their all-electric range, and this extent will determine the severity of the impact that the electrification of the transportation sector will have on the electric power system.

2.2.2.1.2. Infrastructure Characteristics

Due to the differences in the capabilities of conventional gasoline vehicles and plug-in electric vehicles regarding energy density, electric range, and charging times, the layout and operation of the infrastructure which supports the charging of plug-in electric vehicles is markedly different compared to that for fueling gasoline vehicles. Charging PEVs generally takes longer than filling up gasoline tanks at gasoline stations, and the electric range of PEVs are generally shorter than that of conventional gasoline vehicles. Additionally, the character of the electric load associated with vehicle charging is strongly tied to consumer travel patterns. When a consumer plugs in their vehicle, the charging profile must be managed such that electric grid reliability criteria are met and the consumer has sufficient charge to meet their next scheduled trip. Electric grid operators must manage the fueling of these vehicles in real-time within consumer constraints. This is in contrast to gasoline vehicles, where the temporal patterns for the production and delivery of gasoline are only loosely tied to consumer vehicle fueling patterns. Therefore, the paradigm of consumers driving their vehicles until fuel depletion and refilling at stations is not as suitable for PEVs. Alternatively, using such a paradigm will force consumers to change the manner in which their vehicles are used.

The relatively longer time required to charge plug-in vehicles, especially battery electric vehicles, requires that charging infrastructure be installed at locations where the vehicle is parked

for long periods of time. From the vehicle dwelling time distribution presented in Section 2.1.2, this suggest that charging infrastructure be installed at residences and workplaces, which are placed on the electric distribution system. This is confirmed by the average length of the vehicle dwelling time by activity, presented in Figure 52 [61]:

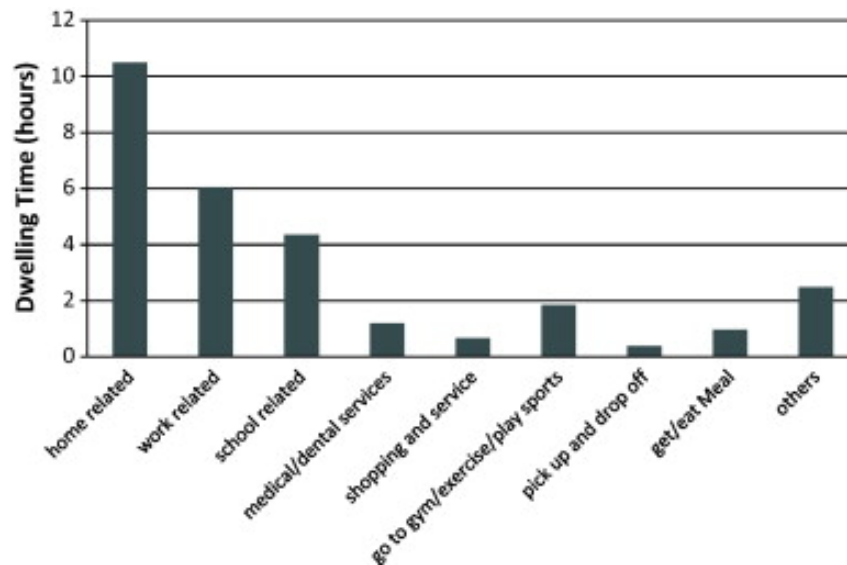


Figure 52 - Average Dwelling Time Length at Different Locations [61]

Vehicles spend an average of 10.5 hours at residences and 6 hours at workplaces. This dwelling time range is suitable for the charging times specified for battery electric vehicles as discussed previously, and the use of PEV types which have lower electric ranges will generally require shorter charging times. Integrating PEVs by charging at these locations may require upgrades to the distribution line capacities and related equipment such as transformers to accommodate the additional load demand on these systems. Control and communications systems must also be installed to manage charging profiles with consideration of real-time power flow and voltage changes.

Charging profile management is also critical for the operation of the PEV charging infrastructure. Without any charging profile management and allowing vehicles to charge immediately upon arrival, the charging profile will generally take the shape presented in Figure 53 [61]:

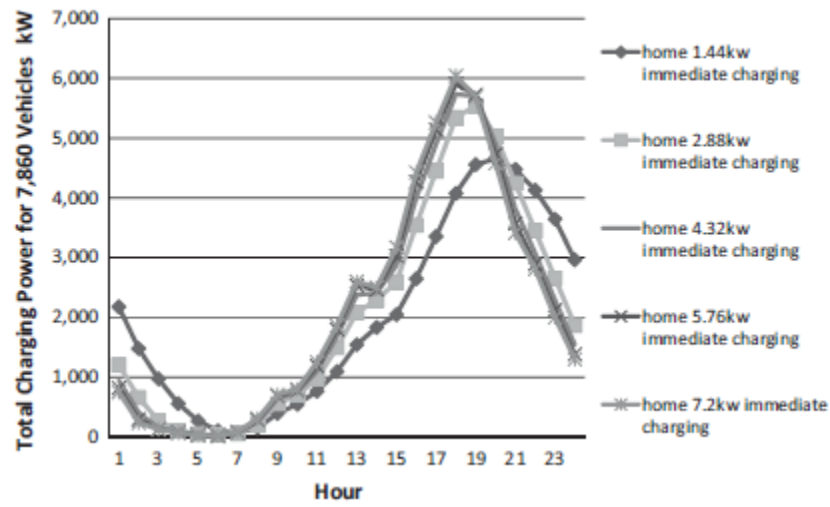


Figure 53 - Daily PEV Charging Profile Shape: Immediate Charging [61]

Vehicles tend to arrive at residences between 5 pm and 7 pm, after the conclusion of the typical workday. This also coincides with the residential peak of the stationary electric load demand, as consumers arrive at their homes and activate appliances and other devices. By allowing immediate charging of vehicles, the charging load will exacerbate this peak. This can have detrimental effects including but not limited to distribution transformer life degradation [96] and increased reliance on peaking generation with subsequent pollutant emissions [97, 98]. A variety of alternative charging management strategies exist, which can shape the magnitude and timing of the PEV charging load based on consumer scheduling in response to the behavior of various systems on the transmission and distribution grids, but requiring various levels of

communication between parties. These strategies are described in Section 4, as part of the model description used in this dissertation.

2.2.2.2. Hydrogen Fuel Cell Vehicles

Another major method for meeting the VMT demand with reduced greenhouse gas and criteria pollutant emissions is through the use of hydrogen fuel cell vehicles or FCVs.

2.2.2.2.1. Vehicle Characteristics

A hydrogen fuel cell vehicle refers to an automobile that uses a hydrogen fuel cell and an electric motor in place of an internal combustion engine. A fuel cell is a device that uses hydrogen fuel in a chemical reaction with oxygen to convert chemical potential energy to electric energy via electrochemistry as opposed to combustion. Electric energy is then used to drive an electric motor for propulsion. This reaction produces no greenhouse gases or criteria pollutants from the vehicle itself, and the only tailpipe output is water vapor. FCVs also carry a small battery to store energy from regenerative braking and supplement the electric motor when needed.

There are many different types of fuel cells which accomplish this task by using different sets of chemical processes and operating at different temperature ranges, but only the proton exchange membrane (PEM) fuel cell is suitable for automobile use. A PEM fuel cell operates at near room temperature and has very fast load-following capability, which allows its power output to respond to variations in the drive cycle. An operational diagram of the PEM fuel cell is presented in Figure 54:

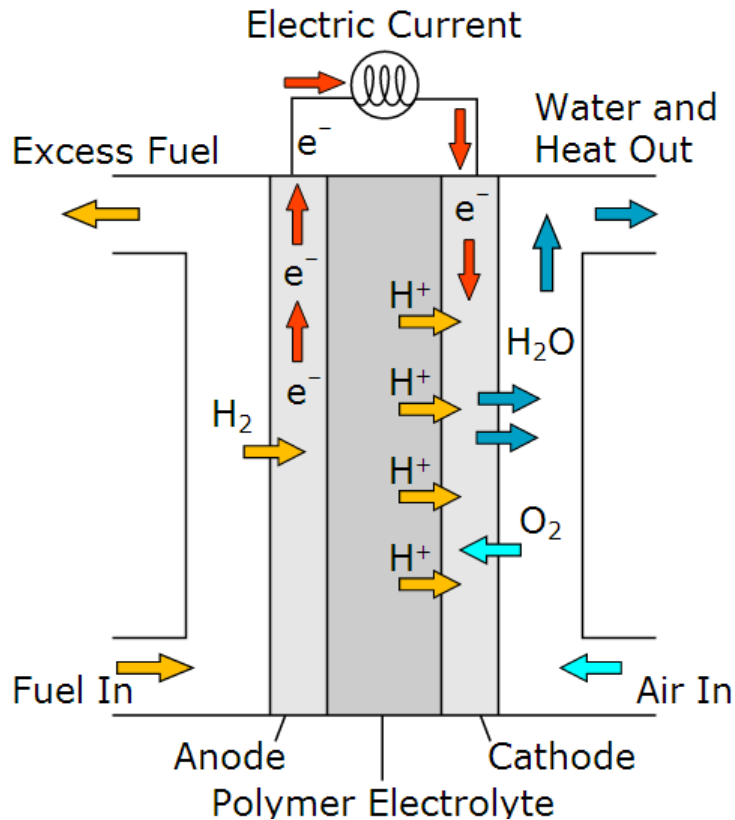


Figure 54 - PEM Fuel Cell Schematic

Fuel cells are typically much more efficient in terms of converting chemical energy to electric energy than combustion engines. A typical FCV with an electric drivetrain is about 2 to 3 times more efficient at converting input energy to kinetic energy for propulsion compared to a modern internal combustion engine.

FCVs are currently slightly heavier than conventional automobiles of the same class, but for a different reason than that of BEVs. The mass of hydrogen required to grant a reasonable driving range is very low, however the fuel cell stack and auxiliary components are typically much heavier than conventional internal combustion engines. For example, the Honda Clarity FCV which is currently available in select markets for lease has a curb weight of 3,582 lbs, and is classified as a midsize car. For comparison, a 2012 Ford Fusion, a typical midsize car has a curb

weight of 3285 lbs. Efforts are currently ongoing to reduce the size and weight of these components.

FCVs do not have the same range limitations as BEVs. In an FCV, energy is typically stored onboard in the form of compressed hydrogen gas at pressures from 350 to 700 bar, storing between 4 to 6.7 kg. This allows current FCVs to have driving ranges between 240 to 300 miles with current technology, similar to many conventional internal combustion engine vehicles. When the hydrogen fuel is depleted, the vehicle can be refilled at a hydrogen station in a manner similar to filling up a conventional internal combustion vehicle at a gasoline station. Hydrogen stations produce hydrogen on-site or have hydrogen delivered via pipeline or truck and stored on-site. When a FCV is being filled up, a high pressure compressor pumps hydrogen gas to the desired pressure and delivers it to the car. Filling times take between 3 to 5 minutes, which is also similar to the filling of conventional vehicles at a gasoline station.

Compared to BEVs, FCVs can be used in a manner much more similar to conventional vehicles. The longer driving range allows these vehicles to be filled up as needed as opposed to at every available opportunity with PEVs, with more and longer trips between fill-ups. The short fill time also eliminates the need to precisely plan a charging schedule as is the case with PEVs. In this respect, the use of FCVs is much less disruptive to consumer driving behavior than PEVs.

In addition, FCVs and PEVs are not necessarily mutually exclusive. A fuel cell stack can take the role of an internal combustion engine in a PHEV, creating a plug-in fuel cell vehicle (PFCV). Such a vehicle was considered in the alternative vehicle greenhouse gas emissions analysis by Argonne National Laboratory [99]. This type of vehicle would operate as a series plug-in electric vehicle until the battery was depleted, after which the fuel cell could be activated to

sustain its charge throughout the driving cycle. When the vehicle returned to a residence, it could be plugged into a 120 V or 240 V outlet to recharge the battery. A PFCV could potentially provide the driving range of a conventional vehicle with zero driving cycle emissions and the benefits of providing a dispatchable load to the electric power system. Additionally, a PFCV could provide redundant methods for meeting consumer transportation needs. The tradeoff of using a PFCV is the added complexity and cost of both the vehicle and the required infrastructure. With current technologies, the cost of alternative drivetrains and the required infrastructure is individually high. Combined with each other, the additional cost can become substantial although this cost would have to be weighed against value of the benefits provided to the overall system.

The main difference between PEVs and FCVs is the environmental benefit and the scale of energy required to produce the hydrogen. Both a PEV and an FCV produce no greenhouse gas or criteria pollutant emissions at the tailpipe, and their primary impacts are due to the demands that they place on other components. For an FCV, the environmental benefit and energy requirement can vary widely and depends on the manner in which the hydrogen is produced. The effect of using FCVs on the electric power system also strongly depends on the fuel pathway to produce hydrogen. These factors are examined as part of this dissertation.

2.2.2.2.2. Infrastructure Characteristics

2.2.2.2.2.1. Hydrogen Production

Hydrogen can be produced from a number of sources using a variety of methods, relying on fossil fuels to different extents. Some of the major methods are briefly described here. More details on these processes and additional hydrogen production methods are discussed by MPR [100]:

- **Steam Methane Reformation (SMR).** Steam methane reformation is a process which reacts methane and water at high temperatures to produce hydrogen and carbon monoxide. The produced carbon monoxide is then reacted with additional water to produce carbon dioxide and more hydrogen. This process requires a thermal energy input. SMR is currently the cheapest method for producing hydrogen on a per kilogram basis. Currently, SMR is the most widely used method for producing bulk hydrogen that is used in gasoline refining and the production of ammonia, accounting for 48 percent of all hydrogen production worldwide [101]. Due to its use of methane in natural gas, SMR produces greenhouse gas emissions and potentially criteria pollutant emissions depending on the composition of the natural gas. These emission rates, however, are still lower than that due to burning gasoline since natural gas has a lower carbon content and fewer auxiliary compounds.
- **Partial Oxidation / Autothermal Reforming (ATR).** Partial oxidation reforming is another chemical process where methane is reacted in a low-oxygen environment to produce syngas, a mixture of hydrogen and carbon monoxide. Autothermal reforming combines partial oxidation with the SMR process, using the thermal energy released from the partial oxidation reaction to supply the thermal energy needs of the SMR process. The primary advantage of this method is that it does not require a large external heat source to maintain the temperatures necessary for the reaction to occur, simplifying reactor design. The tradeoff is that this process is less efficient than the SMR process on an energy basis. Similar to SMR, however, this process still produces greenhouse gases and potentially criteria pollutants.

- **Coal / Biomass Gasification.** Gasification refers to a process similar to partial oxidation, but used on more complex solid hydrocarbon fuels. Compounds such as coal are reacted in a low oxygen environment to produce syngas, with other impurities being produced as side products. The produced carbon monoxide is reacted with steam to produce additional hydrogen and carbon dioxide. Before use, however, the hydrogen stream must be purified by removing the excess products from the gasification process. Similar to the previous two processes, the reliance on coal or biomass produces greenhouse gases and criteria pollutants of varying extents. Along with SMR, coal gasification is widely used due to the abundance of coal resources in the U.S, and is a relatively proven technology.
- **Electrolysis.** Electrolysis refers to the production of hydrogen by using electric energy to split water into hydrogen and oxygen. In this process, a voltage difference is applied across two electrodes in a conductive medium, producing hydrogen gas at the cathode and oxygen gas at the anode. The conductive medium could be an aqueous solution or a solid electrolyte immersed in water. The process of electrolysis itself does not emit any greenhouse gas or criteria pollutant emissions. The emissions impact of electrolysis depends on the source of the input electric energy. If the input electric energy is sourced from fossil fuels, using electrolysis results in greenhouse gas and criteria pollutant emissions from the additional use of fossil fuels to meet the load from electrolysis. If the input electric energy is sourced from renewable resources such as wind, solar, or geothermal power, electrolysis does not contribute to greenhouse gas or criteria pollutant emissions. The efficiency of current electrolyzers is between 56 to 73 percent, corresponding to 70.1-53.5 kWh/kg of hydrogen produced. This efficiency represents the

energy equivalent of the produced hydrogen relative to the electric energy input. Additionally, the production of 1 kg of hydrogen consumes 8.9 liters of water [101]. Compared to SMR and coal gasification, electrolysis is only used to produce hydrogen on a small scale at current. Electrolysis is primarily used in applications that require very high hydrogen purity, since the fossil-based processes do not produce a pure hydrogen stream. Additionally, the hydrogen production capacity of current electrolyzer units is fairly small compared to large SMR plants. Although electrolysis is a fairly proven process, the dependence on electricity price and lack of economies of scale has rendered it to be more expensive than the fossil-based processes [101]. Increases in the price of natural gas and the desire to reduce fossil fuel consumption have the potential to alter this trend.

Additional processes exist for the production of hydrogen, however, these four processes represent the currently proven and available methods. Methods which are currently under investigation or development are discussed by MPR [100].

2.2.2.2.2. Hydrogen Delivery

Once hydrogen is produced it must be delivered to hydrogen stations to be used as transportation fuel. There are many pathways for hydrogen production and delivery listed in brief as follows:

- **On-site Production.** Individual hydrogen stations can have reforming or electrolysis units on site to produce hydrogen. The produced hydrogen is then liquefied or compressed for storage on site. Additional electric load due to liquefaction, compression, and/or electrolysis is placed on the distribution system. This requires that the individual hydrogen stations have direct access to a natural gas stream. Current examples using this

method include the SMR hydrogen station in Oakland, California and the electrolysis-based hydrogen station in west Los Angeles, California [102].

- **Hydrogen Delivery by Truck.** Produced hydrogen is liquefied or compressed at the site of production and carried in large trucks to individual hydrogen stations. The electric load due to liquefaction, compression, and/or electrolysis can be placed on the higher voltage distribution lines or sub-transmission lines depending on the location of the production facility. Current examples using this method include the hydrogen station in Irvine, California which stores liquid hydrogen and the mobile refueler in Sacramento, California which stores compressed hydrogen [102].
- **Hydrogen Delivery by Pipeline.** Produced hydrogen is injected into a high pressure pipeline which pumps it from the site of production to individual hydrogen stations. The electric load is associated with compressor stations that are distributed throughout the network. This requires the installation of an extensive piping infrastructure similar to the natural gas pipeline network. Current examples using this method include the hydrogen station in Torrance, California [102].

2.2.2.2.2.3. Hydrogen Distribution / Fueling

Once hydrogen has been delivered to individual fueling stations, it must be prepared for fueling into hydrogen fuel cell vehicles. Hydrogen stations must store enough hydrogen to meet the expected demand between hydrogen deliveries, and be able to provide the fuel at the pressures that the vehicles are designed to operate at.

To store hydrogen with high density and therefore minimize the footprint of a given station, hydrogen is typically stored as a liquid. Delivered hydrogen is either liquefied on site or

delivered as liquid, and balance of plant systems maintain this state when the fuel is stored on-site. This requires electric energy to operate and maintain the cooling systems, however.

Hydrogen fuel can be stored in the gaseous state at the expense of increasing the station footprint or decreasing the mass storage capacity of the station.

Currently, hydrogen vehicles are typically designed to operate on gaseous hydrogen at pressures of either 350 or 700 bar, depending on the vehicle type [103]. To prepare for fueling, liquid hydrogen is vaporized and compressor systems of one or more stages pressurize the hydrogen vapor to above the vehicle operating pressure. This also requires electric energy, and control systems need to be in place to regulate the hydrogen flow rate into the vehicles. The character of the hydrogen fueling electric loads will vary from station to station, and may be more or less correlated with consumer fueling patterns.

Since the operation of hydrogen fuel cell vehicles is very similar to that of gasoline vehicles, where consumers drive until they need to visit a station to refill, the siting of hydrogen stations to ensure adequate access for all consumers is critical. Studies regarding the optimal siting of early hydrogen stations in California have been conducted by UCI's National Fuel Cell Research Center [104, 105], optimizing station siting based on a variety of metrics such as service coverage, market deployment, and connectivity throughout the state.

2.2.3. Water Supply Sector

2.2.3.1. Seawater Desalination

Desalination refers to the processes by which salts and other dissolved solids are removed from a saline water stream, separating it into two streams: one with highly purified water and another with highly concentrated brine. These processes can be used on any saline water body, including

brackish water and seawater. Since the analyses of this dissertation are focused on the use of desalination for large-scale water supply augmentation in California, this discussion is focused on seawater desalination. Being located on the western coast of the U.S., California has access to the Pacific Ocean as a large source of saline water. It is also important to note that due to the physical nature of the following processes, desalination plants typically operate in a steady, base-load fashion. The electric energy consumption of these plants does not vary significantly on short timescales. The primary methods by which desalination is carried out are discussed here.

2.2.3.1.1. Membrane

Membrane seawater desalination refers to the use of a semi-permeable membrane to separate solvent (water) from solute (salts and other dissolved solids). The most popular form of membrane desalination is **reverse osmosis (RO)**. This process uses electric energy to pump inlet saline streams to very high pressures, on the order of 55 to 82 bars for seawater desalination. The pressurized saline stream is then exposed to a semi-permeable membrane assembly, which selectively filters out salt and other dissolved solids and allows only the solvent to pass through. The pressure is needed to force the water through the membrane, as well as to overcome the osmotic pressure created by the difference in salt concentration on the two sides of the membrane. This produces two streams: a relatively salt-free stream on the other side of the membrane, and a highly concentrated brine which remains on the front side of the membrane. A simple diagram of a reverse osmosis system is presented in Figure 55 [106]:

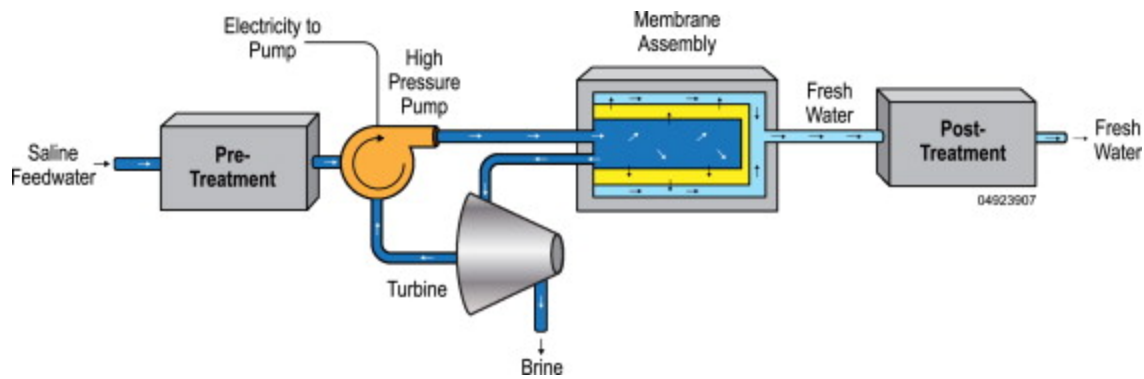


Figure 55 - Simple Reverse Osmosis System Layout with Energy Recovery [106].

Due to the pressures required, this system is fairly energy intensive and requires a large amount of electricity, on the order of 4-6 kWh/m³ of product [106, 107]. To reduce this energy consumption, energy recovery systems are often fitted consisting of a turbine that harnesses the energy in depressurizing the outlet brine stream.

Membrane desalination requires pretreatments to remove sand, turbidity, bacteria to protect the membrane from damage. Most recent developments combine microfiltration with RO as the pretreatment. In spite the pretreatment effort, organic carbon in the water is not efficiently removed, which can cause membrane organic fouling followed by biofouling. Membrane fouling dramatically lowers the efficiency of water production and increases the energy demand [108].

2.2.3.1.2. Thermal

Thermal desalination refers to the use of thermal energy to separate solvent (water) from solute (salts and other dissolved solids). Thermal energy can be procured from the waste heat of gas-turbine or steam-turbine power plants if it is of a sufficient temperature, by the combustion or fissioning of fuels, or by solar energy input. There are two primary plant configurations for thermal desalination processes:

Multi-Stage Flash (MSF) distillation is a process that separates solvent from solute by evaporating saline streams in low pressure chambers or “effects”. This process takes in seawater and heats it using thermal energy input before introducing it into the first low-pressure chamber. Being at an elevated temperature and being introduced into a low-pressure environment, the seawater flash evaporates to adjust to the boiling point dictated by chamber conditions. The vapor is condensed by exchanging heat with the intake seawater flow before the latter is heated, and freshwater is collected. This also has the effect of pre-heating the seawater before it is primarily heated by the thermal energy input. Brine remains in the chamber, where it is passed to the next effect which is at a lower pressure. This process repeats for all of the effects until the pressure required to initiate flash evaporation is too low. A schematic of a multi-stage flash system with three effects is presented in Figure 56 [106]:

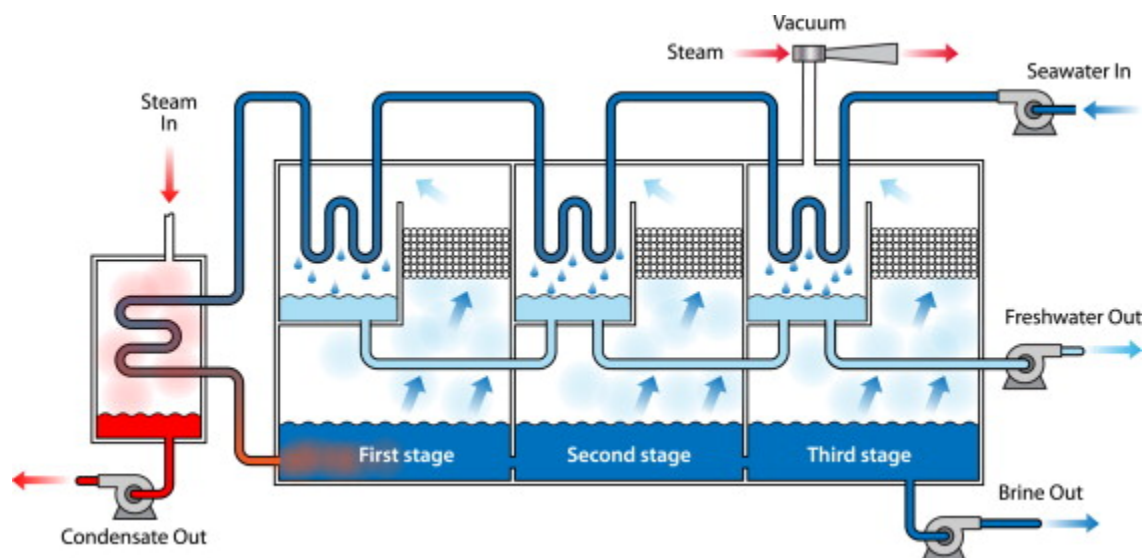


Figure 56 - Multi-Stage Flash System with 3 Effects [106]

MSF systems do not require extensive pretreatment of the seawater, other than the introduction of anti-scaling compounds to prevent the formation of salt layers on the heat transfer surfaces, which reduces heat transfer effectiveness and therefore the efficiency of the system. In general,

MSF systems are very energy intensive. Electric energy on the order of 2-2.5 kWh/m³ is required to operate the pumping and vacuum equipment, and thermal energy consumption on the order of 52.8-78.3 kWh/m³ is required to sufficiently heat the water [106, 107].

Multi-Effect Evaporation (MEE) distillation is also a process that separates solvent and solute through evaporation of seawater through heating and introduction into low-pressure chambers. The difference between the MEE and MSF processes lies in the manner that evaporation is carried out. In an MEE system, the feed seawater is pumped into a series of nozzles placed at the top of pressure vessels called effects. In each effect, the nozzles spray the seawater onto a series of tubes containing hot steam and receive thermal energy through conduction and convection, causing it to separate into a two-phase mixture. The liquid phase, which contains all of the salt and other chemical constituents, falls to the bottom of the effect where it is collected and discharged as brine. The remaining content consists of vapor-phase water and non-condensable gases that may have been dissolved in the intake seawater. This vapor mixture rises to the top of each effect, where the non-condensable gases are removed and discharged into the atmosphere, and the vapor-phase water is fed into the tubes of the next effect to be used as the hot-side heat transfer fluid for another spray of seawater. Once the fluid in the tubes is cooled, it is condensed and collected as distillate. The process continues sequentially for each effect in the system. Each subsequent effect is maintained at lower pressures than the previous effect. This is necessary to encourage evaporation while the temperature of the hot-side heat transfer fluid in each subsequent effect is decreasing in temperature. This vacuum is maintained by vacuum pumps operating on the last effect of the system. A schematic of an MEE system with three effects is presented in Figure 57 [106]:

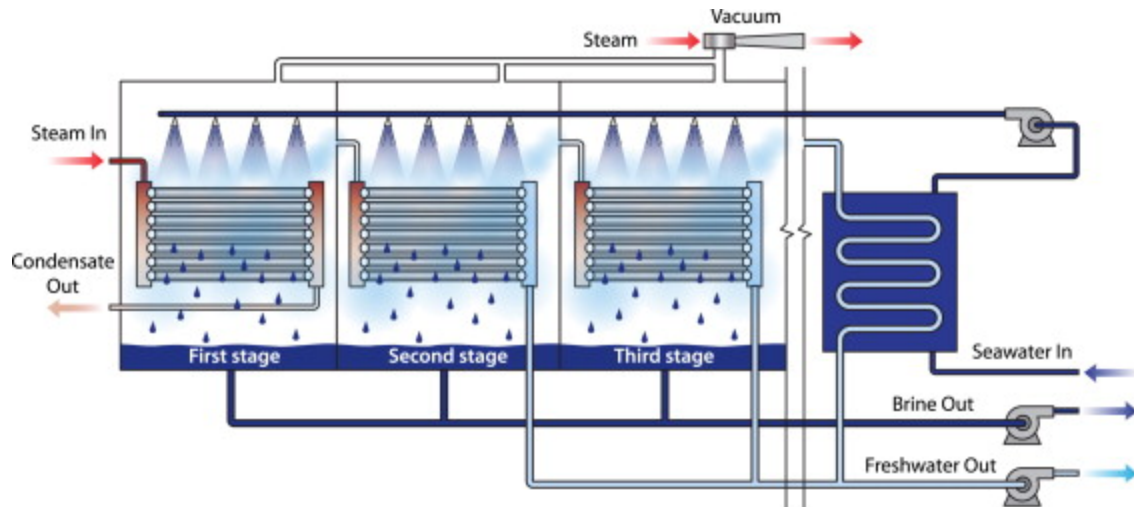


Figure 57 - Multi-Effect Evaporation System with 3 Effects [106].

The MEE system has a larger heat transfer surface area compared to the MSF system, allowing more efficient use of the supplied thermal energy. This allows MEE systems to have lower thermal energy requirements compared to MSF systems, on the order of $40.3 - 63.9 \text{ kWh/m}^3$. Electric energy consumption is similar due to the pumping needs of the system, at around $2\text{--}2.5 \text{ kWh/m}^3$ [106]. The operation of an MEE process is fairly robust, and does not require extensive pretreatment of the feedwater. The primary operating concern for this system is due to scaling on heat exchanger tubes, which reduces heat transfer effectiveness. Additionally, these systems can be coupled with a thermal vapor compressor to reuse entrained vapor in the last effect of the system to supplement the mass flow of motive steam, reducing energy requirements.

2.2.3.2. Urban Water Conservation

Urban water conservation refers to a wide range of measures aimed at reducing the demand of water needed to perform tasks in the urban environment as defined in Section 2.1.3.2. Many of these measures are dependent on consumer behavior, while others are not. Urban water conservation also has strong energy implications, since while it is a lower portion of the water demand compared to agricultural use, it comprises the majority of the water-related energy use

[63]. A brief overview of the measures considered as part of urban water conservation in different areas is listed as follows:

- **Reducing Indoor Residential Water Use.** This involves the installation of low flow appliances for toilets, showers, dishwashers, faucets, and washing machines. Additionally, this can involve economic incentives to encourage consumers to reduce the amount of water utilized for these purposes.
- **Reducing Outdoor Residential Water Use.** This involves the reduction of water use in landscaping for lawns, turfs, and gardens, or the removal of these areas in part or altogether. This can be accomplished by changes in land use or installation of more efficient landscaping irrigation systems.
- **Fixing Leaks.** This involves identifying and fixing leaks in water distribution systems to reduce the loss of water in transport.
- **Reducing Commercial and Industrial Water Use.** This involves the reduction of water use in industrial processes such as manufacturing, water needs for equipment cooling, and commercial landscaping, laundry, kitchen or restroom purposes. The varied nature of water use in the commercial and industrial sector renders the measures to achieve these reductions as a very diverse set. Measures can also be incentivized by appropriate rate structures, however, the elasticity of the commercial and industrial water demand may be less than that of the residential demand.

Different estimates have been given for the potential reduction that can be obtained by these measures, ranging from about 2.0 – 3.1 MAF/yr [109, 110]. Characterizing this potential and how it changes with time is an ongoing topic of work.

2.2.3.3. Water Reuse

Water purification and reuse refers to additional treatment of wastewater treatment plant effluent to standards that allow it to be reused as part of the water supply. Water that is used in urban and agricultural purposes is conveyed to a wastewater treatment plant which removes harmful contaminants from these streams to render it suitable for discharge into the river or ocean bodies. Wastewater treatment plants must obtain permits to discharge effluent such as a National Pollutant Discharge Elimination System (NDPES) permit from the U.S. EPA [32], with consideration of water quality at the point of discharge and connected water bodies. While wastewater effluent may be treated and cleaned to allow environmental discharge, treatment to higher levels are needed to allow reuse of this water as part of the water supply.

Water reuse refers to the routing of effluent from wastewater treatment plants to reclamation plants, where additional treatment processes are employed to produce effluent that meets the standards required to be applied towards potable uses. A simple schematic of this process for the Orange County Water District is presented in Figure 58 [111]. In this particular example, water from the reclamation plant is re-injected into local groundwater aquifers, where it is treated as part of the standard groundwater supply.

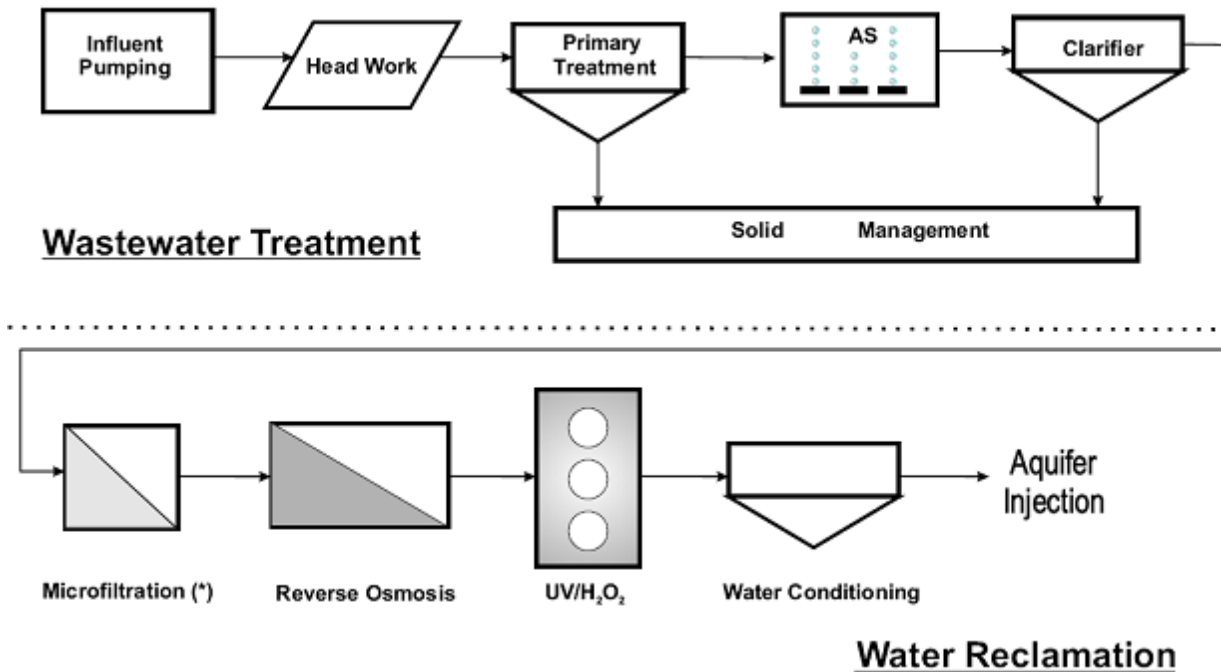


Figure 58 - Wastewater Treatment and Water Reclamation [111]

Three primary processes are used on wastewater effluent. Microfiltration acts to remove suspended and colloidal solids, reverse osmosis removes dissolved constituents, and the UV/H₂O₂ process removes residual trace elements and disinfects the stream. Once this stream has been produced, it can be routed through two different paths for reuse.

First, it can be injected into existing surface water or groundwater reservoirs and considered similarly to natural inflows into those reservoirs. This water is withdrawn and subject to pre-treatment processes similar to natural water supplies. This is termed **indirect potable reuse**.

Alternatively, it can be directly routed for use in particular applications instead of being injected into reservoirs. In this case, the reclaimed water is not subject to pre-treatment processes in the same vein as natural water supplies. This is termed **direct potable reuse**.

Indirect potable reuse subjects the reclaimed water stream to a redundant stage of pre-treatment. Since this water has already been treated to potable standards in the water reclamation plant, it does not need to undergo similar processes to during pre-treatment. Indirect potable reuse, however, is used for groundwater level stabilization and for public perception concerns.

The potential for water reuse to contribute towards augmenting water supply in a given region is limited by the wastewater treatment capacity in that region. Since water reuse in this application is based on the treatment of wastewater treatment plant effluent, the amount of water that can be reclaimed cannot exceed that amount.

2.3. Framework of the Study

This section has provided an overview of the operating practices of the infrastructures in major resource sectors, and some of the constraints within which current and emerging sustainability-oriented technology and management options much function within. Additionally, an overview of the physical and functional characteristics of these options in different primary resource sectors has been provided.

Studies have been performed which have evaluated the performance of some of these options while taking into account some of these constraints. Details of these studies will be provided in the literature review for each component study of the dissertation, in Sections 5, 6, and 7. The majorities of these studies, however, have been very specific in scope and therefore have focused on either a specific infrastructure aspect or characterizing performance within the context of resource sectors in isolation. Additionally, many of the studies which do recognize the cross-sector impacts of deploying these options have used static assumptions for the operation and behavior of co-dependent resource sectors, without simultaneously considering the integrated

constraints of these sectors, or have only considered relevant interactions for specific deployment scenarios.

In this context, this work seeks to address these gaps in understanding regarding the performance and preferred role of different options in contributing to meet sustainability goals. Evaluations of options within individual resource sector contexts are carried out to determine relevant infrastructure impacts and effects on constraints. Next, evaluations of different option deployments within the integrated context of two resource sectors simultaneously is carried out, using spanning scenarios which allows dynamic evolution of the technology portfolio and infrastructure operation of co-dependent resource sectors. This allows examination of the nature and implication of interactions between resource sectors not only for a specific scenario, but the sensitivity of these interactions to different technology pathways. Finally, the knowledge gained from the earlier analyses will be used to evaluate different pathways for simultaneously meeting sustainability goals for the combined electricity-transportation-water supply system, taking into account the dynamic evolution of their behavior and cross-sector impacts. Overall, identifying these interactions can provide robust insight into the development of pathways to meet sustainability goals moving into the future. This understanding will help policy planners to identify and avoid unintended detrimental effects and obstacles towards meeting sustainability goals, and to leverage beneficial interactions to overcome traditional obstacles towards meeting these goals.

Chapter 3: Approach

This section will focus on the proposed approach towards meeting the objectives stated previously.

Task 1: Understand the motivation behind sustainability goals in major resource sectors.

In order to understand how to shift the operations of major resource sectors towards a more sustainable paradigm, it is important to understand the nature of the problem. Each major resource sector contributes to the issue of unsustainable satisfaction of societal needs in different ways, and is responsible for different shares of these issues. Before embarking on how to determine the preferred pathways for meeting sustainability goals, an understanding of how current resource sectors contribute towards unsustainability must be developed. This helps to identify the aspects of these resource sectors that must be targeted for change to meet sustainability goals.

Task 2: Characterize the technical operating constraints of major resource sectors.

Electricity, transportation, and water supply services are not provided without the presence of significant infrastructures which must be precisely managed and operated for robustness and quality. The introduction of new technology or management options into these infrastructures must not compromise their ability to provide robust and quality services to satisfy societal demands. Therefore, it is critical to understand the operating constraints and practices of the infrastructures in these major resource sectors such that the framework which new options must work within can be identified.

Task 3: Develop a modeling platform that captures the inter-dependency of the key infrastructures of major resource sectors and the sensitivity of their operation to extra-sector technology options.

With an understanding of the motivation behind sustainability goals and the operating constraints and practices of major resource sectors, a modeling platform which can take into account these aspects, their interaction, and sensitivity to the deployment and operation of emerging technology and management options must be developed. This is accomplished by developing models of individual resource sectors: electric grid, transportation vehicle fleet, and water reservoir network while keeping in mind their co-dependencies and merging them together into a coherent platform. The details of these models and their connections will be presented in Section 4.

Task 4: Characterize the capabilities of technological options for meeting individual sector sustainability goals.**

Before evaluating the benefits and disadvantages of deploying options in the context of co-dependent resource sectors, it is important to establish a baseline for the performance of these options within their primary, individual resource sectors. This allows us to characterize the fundamental impact of these options on individual infrastructures, such that it can be determined whether the effects of interacting with options in co-dependent infrastructures are beneficial or detrimental. This is carried out for the electricity sector and the water supply sector. The transportation sector is not considered in isolation as mentioned in Section 1.5.

Task 5: Use the developed platform to assess the capabilities of technological options for meeting holistic sustainability goals within constraints while capturing relevant synergies and mapping out the option portfolio space.

The next phase is to evaluate the performance of emerging sustainability-oriented options in the context of multiple, co-dependent resource sectors, identifying the nature and beneficial or detrimental implications of interactions between options and the dynamic evolution of resource sector infrastructure behavior. This is accomplished first by considering paired resource sector contexts (electricity and transportation, electricity and water supply), and finally by considering an integrated, tri-sector context (electricity-transportation-water supply).

Task 6: Advise the deployment of technological solutions in each sector to most effectively contribute to satisfying holistic sustainability goals.

With an understanding of the performance of different options in the context of the sustainability of the combined system of all resource sectors, recommendations can be made regarding the preferred selection and deployment of sustainability-oriented options in each individual resource sector, such that holistic sustainability goals can be most effectively satisfied. A sensitivity to the factors that give rise to these recommendations and what trends can affect either their strength or direction is discussed and presented.

Chapter 4: The UCI-STREET Model

The UCI Spatially and Temporally Resolved Energy and Environment Tool (UCI-STREET) is the modeling platform utilized to conduct this study. In its current state, the UCI-STREET model consists of a number of detailed models representing the electric grid, light-duty transportation, and water supply sectors and the details of their respective sustainability-oriented options integrated into a single platform. This approach allows the model to assess two primary aspects:

- The sensitivity of the technical and economic performance of one sector due to changes in the options used and operation of the others, and
- The sensitivity of the combined technical and economic performance of the entire integrated system to interferences and synergies between the operations of the different sectors.

A simplified, bulk diagram the interactions included in the UCI-STREET model is presented in Figure 59.

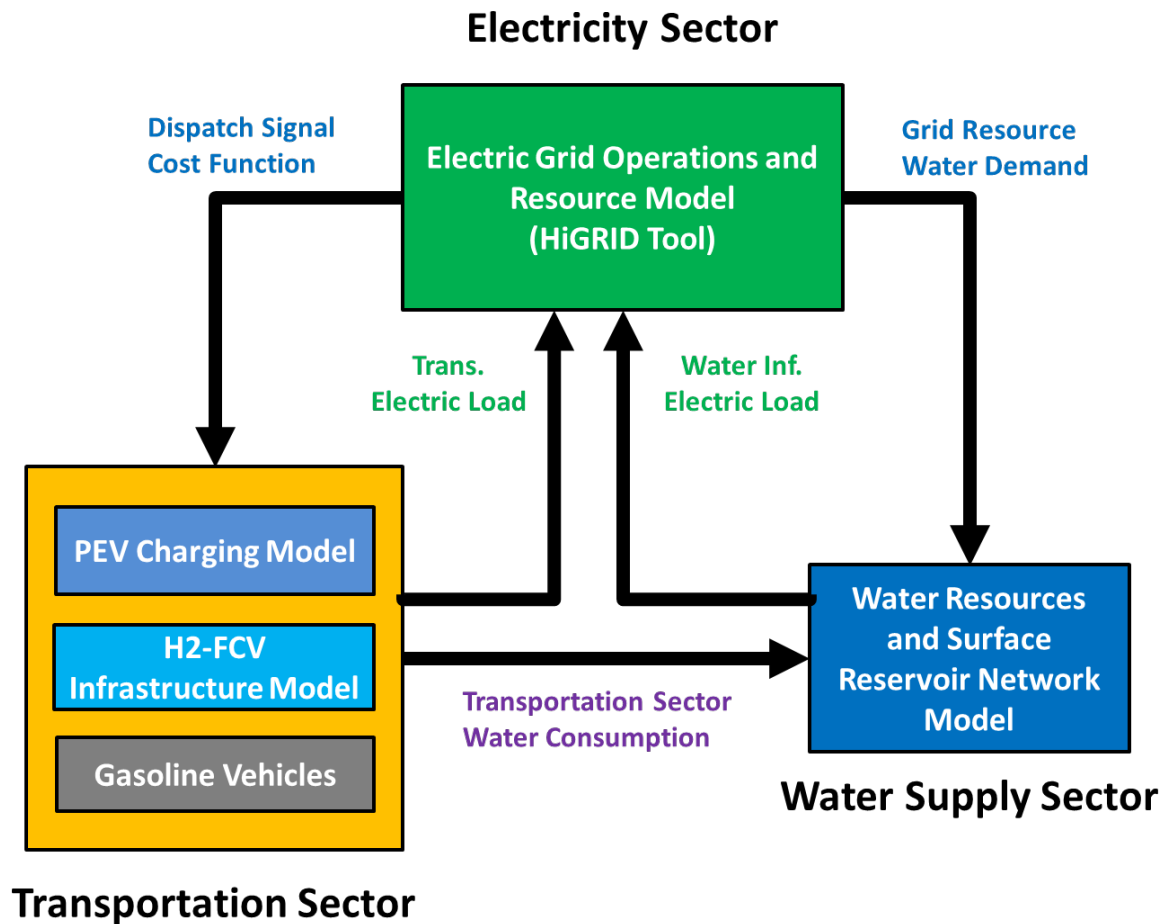


Figure 59 - Bulk Overview of the UCI-STREET Model Component Interactions

Each of the model blocks consist of a number of smaller-scale, detailed models for different aspects of the system, each with its own inputs and outputs. A description of these models and their overall integration is the focus of this section. In addition, a large number of outputs are also available from each model, which will be described in the relevant section.

Many components of the model have been described in part in different publications, and certain figures and text have been presented with modification from these publications as follows:

- Samuelson, S., Mueller, F., Eichman, J., **Tarroja, B.** Advanced Power and Energy Program. 2013. *Piloting the Integration and Utilization of Renewables to Achieve a Flexible and*

Secure Energy Infrastructure. California Energy Commission. Publication number: CEC-PIR-08-033.

- **Tarroja, B.**, et al., *Spatial and temporal analysis of electric wind generation intermittency and dynamics*. Renewable Energy, 2011. **36**(12): p. 3424-3432.
- **Tarroja, B.**, F. Mueller, and S. Samuelsen, *Solar Power Variability and Spatial Diversification: Implications from an Electric Grid Load Balancing Perspective*. International Journal of Energy Research, 2012. **37**(12): p. 3424-3432.
- Eichman, J.D., Mueller, F., **Tarroja, B.**, Schell, L.S., Samuelsen, S., *Exploration of the integration of renewable resources into California's electric system using the Holistic Grid Resource Integration and Deployment (HiGRID) tool*. Energy, 2013. **50**(1): p. 353-363.

Additionally, some of these components are described in publications that have been currently submitted to refereed journals as follows:

- **Tarroja, B.**, AghaKouchak, A., Samuelsen, S., Sobhani, R., Feldman, D., Jiang, C.S., “Evaluating Options to Stabilize the Water-Electricity Nexus in California: Part 1 – Stabilizing Major Reservoir Levels”, Science of the Total Environment, 2014. **Submitted as of March 2014**
- **Tarroja, B.**, AghaKouchak, A., Samuelsen, S., Sobhani, R., Feldman, D., Jiang, C.S., “Evaluating Options to Stabilize the Water-Electricity Nexus in California: Part 2 – Greenhouse Gas and Renewable Energy Utilization Impacts”, Science of the Total Environment, 2014. **Submitted as of March 2014**

4.1. Electricity Sector – The Holistic Grid Resource Integration and Deployment (HiGRID) model

Various tools have been developed to analyze energy systems and grid load balancing, each capable of taking into account different sensitivities and options to varying levels of detail.

Connolly et al. compiled a list of the most prominent energy analysis tools available [112]. The available tools and their features were cross-referenced against the requirements for this work to establish a list of appropriate tools. Of the 37 tools explored by Connolly, only four tools include modeling of conventional generation and renewable energy and the ability to explore energy storage and demand response at a sufficiently high resolution (1 hour or less) to capture

the interactions between each resource. The four tools are HOMER, H₂RES, TRNSYS and EnergyPLAN. The first three of those tools are best suited for small, remote or islanded systems [113-115] and while they can be stretched to analyze larger systems, they do not have the functionality required to incorporate many generators and many resource types adequately. EnergyPLAN has many of the desired features including hydroelectric modeling and the ability to look at transportation constraints and CO₂ emissions for large systems; however, a requirement for this work is the capability to explore the infrastructure sensitivities to installing renewables, including impacts on other generators including base load, peakers and load-followers. While EnergyPLAN separates the geothermal and nuclear from other generation, it lumps the remaining generation (predominantly coal and natural gas) into a single category [116]. To carry out this work, the capability to capture the details of how variable renewables impact the large scale electric power system is necessary. Thus, none of the reviewed tools could adequately provide this functionality.

There are a number of tools that have the potential to model the breakdown between every type of generation both renewable and non-renewable and the externalities associated with increasing renewable penetrations, including PLEXOS, VENTYX and GE MAPS [117-119]. These tools use a combination of unit commitment and economic dispatch to calculate the price of electricity and generator dispatch for a large grid system. PLEXOS and VENTYX include both types of constraints, while GE MAPS considers mainly generator operating constraints and transmission constraints to a lesser degree. All three of the above-mentioned tools rely on data from the utilities and grid system operators and operate on hourly or sub-hourly timescales and are able to represent a diverse range of renewable generation coupled with conventional generation, while simultaneously satisfying reliability requirements. However, they are not very amenable to

implementation of complementary technologies (e.g., energy storage, demand response) or interfacing with the dynamic operation of electric loads in other resource sectors (transportation, water) except when the response of these options directly aligns with market bidding strategies. In an effort to maintain the required functionality and have greater control over the implementation of complementary technologies as well as interactions with other resource sectors, an energy modeling tool was developed that allows for analyses of large (i.e., statewide, regional) on an hourly timescale, described in the next section.

4.1.1. HiGRID Overview

The HiGRID model was developed to resolve interaction between different types of generation (e.g., gas turbines, combined cycle plants, renewable generators) and supporting equipment in an effort to evaluate the cost and benefit of installing renewable generation capacity. The time resolution is hourly and the analysis area can range in size from a city to the entire state of California depending on the input data. Applied to the state of California, it has the capability to integrate conventional generators including coal, nuclear, natural gas and hydroelectric with an array of both local and regional renewable generation.

Each resource data signal is temporally coincident, because many of the phenomena that contribute to variability in renewable generation such as wind speed, temperature, cloud cover, and humidity also affect the operation of other generators as well. For example, on a cloudy day, while the solar power generated will be lower than on a clear day, the ambient temperature will be lower as well and can result in lower cooling needs. Figure 60 presents the flow diagram for the HiGRID model. The systems modeled in HiGRID are composed of generation resources, both renewable and conventional, and additional complementary resources such as energy storage and demand side-management strategies that all act to balance the system by not only

providing sufficient energy to meet the demand, but in the case of the model for California, also must provide sufficient generation reserves to maintain reliability.

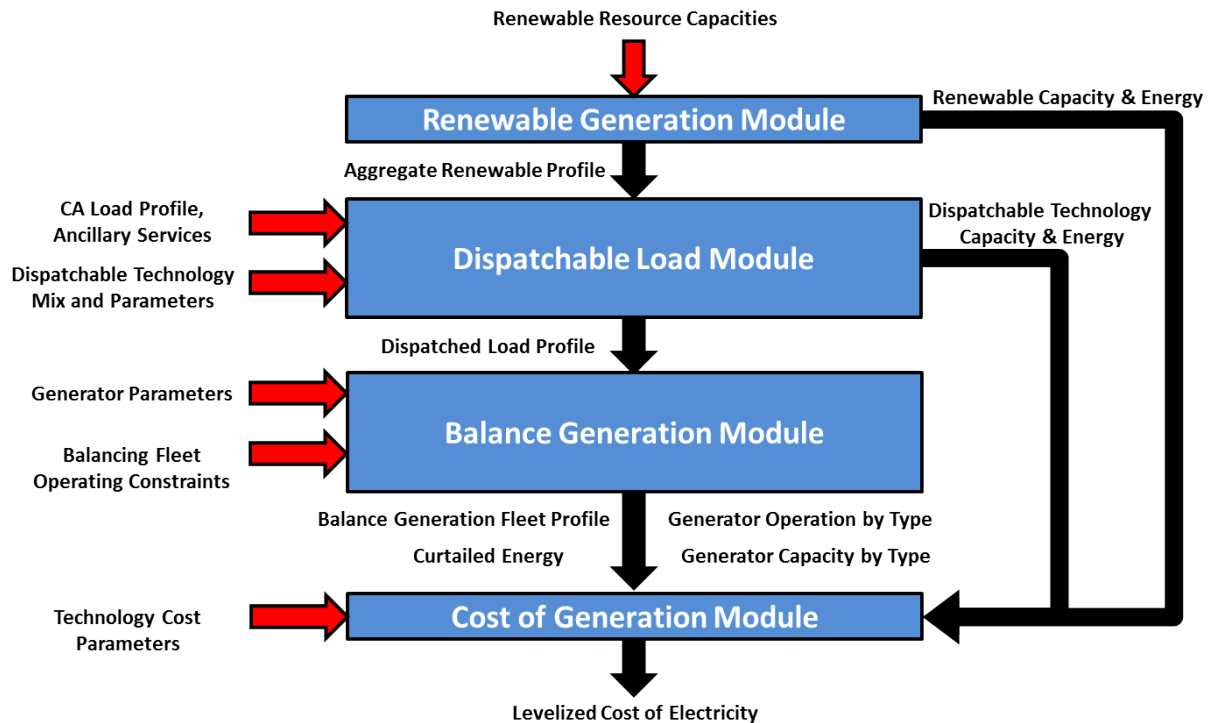


Figure 60 - HiGRID Model Flowchart

Specifically, the HiGRID tool makes use of 4 distinct modules. These modules are described in brief as follows, with more detailed descriptions present in the ensuing sections.

Renewable Generation Module: This module takes the capacity of different renewable resources as an input, and uses models of each type to determine the time-resolved profile of power generation and power delivered to load for each resource type. The costs associated with utilization of these resource types is also calculated and factored into the cost of generation module. The generation profile of the combined renewable resource mix is composed and fed into the dispatchable load module.

Dispatchable Load Module: The dispatchable load module takes the time resolved electric demand profile and aggregate renewable generation profile as inputs to compose the net load profile. This module dispatches complementary technologies and loads in response to the behavior of the net load profile or the behavior of balance generators through an iterative process, within the operating constraints of each technology. Included in this module are models for hydroelectric generation, energy storage (thermal and electric), demand response, electric vehicle charging, and hydrogen production/storage. The option for some of these technologies to meet ancillary service requirements for the grid such as spinning reserve and regulation capacity is also available. After all selected technologies are dispatched, the adjusted net load profile and the remaining portion of ancillary services which balancing generators must meet is produced and fed into the balance generation module.

Balance Generation Module: The balance generation module determines the sizing and dispatch of base-load, load-following, and peaking generation that is required to meet the adjusted net load profile and remaining ancillary services, within the performance capabilities of different generator classes. Base-load generators such as nuclear and coal power plants are dispatched on an installed capacity and monthly capacity factor basis that includes planned outages, and have flat operating profiles within each month. Load-following and peaking generators are dispatched to meet the remainder of the adjusted net load profile. Each of these classes of generators has performance limitations including minimum operation time, ramping limitations, part-load operation range, and generator size. Additionally, the maximum and minimum number of load-followers and peaking generators are also considered. The operation of balance generators determined in this module can also be re-routed back into the dispatchable

load module to allow technologies to respond specifically to certain aspects of the balance generator fleet (i.e. number of peaking generators) in an iterative process.

Cost of Generation Module: Once all of the installed capacities, operational characteristics and resource consumption of all of the different types of technologies considered have been computed, these measures are fed as inputs into the cost of generation module. This module is based in part on the California Energy Commission (CEC) model for determining the Levelized Cost of Electricity (LCOE) and has been developed further to include a wide range of technologies and unique operation methods.

A summary of the technologies used in the HiGRID model are presented in Table 4. The HiGRID tool can operate for the entire state of California. The California model includes regional resources as well as distributed wind and solar generation plants (i.e., local to the point of use). The California model includes all generation, in-state or out-of-state, that is required to meet the electric demand.

Table 4 - Technologies Included in the HiGRID Model

HiGRID Technologies	
	California Model
Renewable Generation	Local and regional wind Local, Rooftop fixed axis PV Regional, Utility 1-axis tracking PV Regional, Utility 2-axis tracking PV Solar Thermal Trough Plant Small hydropower Geothermal Biomass/Biogas
Dispatchable Generation	Demand Response Electric Vehicle Charging Electric Energy Storage Hydrogen Electrolysis for Fuel Cell Vehicles
Base load Generation	Nuclear Coal Geothermal
Balance Generation	Gas Turbines Combined Cycles

4.1.2. Renewable Module

The details of the renewable module are described here.

4.1.2.1. Wind Modeling

Wind generation is modeled following the process described in Tarroja (2011), with data drawn from the Wind Integration Dataset developed by 3TIER in collaboration with the National Renewable Energy Laboratory (NREL) [120]. The area selected to support this work includes predominantly California with resources in Tehachapi, Beaumont, Palmdale and Granite Mountain as well as wind resources in Colorado and New Mexico. Resource limitations are calculated from the WWSIS study and from the Renewable Energy Transmission Initiative report released in May 2010 that describes the current status and future possibilities for siting renewables and transmitting their power [121, 122].

4.1.2.1.1. Wind Data Acquisition and Characteristics

The specific wind power dataset implemented for use in the HiGRID code has been obtained from the NREL Western Wind and Solar Integration Project (NREL-WWSI) [123]. Specifically, the data provides 10-minute temporal wind speed and potential power for 2 km by 2 km potential wind sites across the United States for the years of 2004 through 2006. Each 4 kilometer square area of the study is assumed to contain ten 3-MW wind turbines. Details of the dataset compilation are presented in the report presented by the 3TIER Corporation [124]. The electric power output and effective wind speed from each of these areas were determined using a mesoscale model developed by 3TIER Corporation. The performance curve for the Vestas V90 3.0 MW turbine was used to determine the wind power output potential of each block.

The WWSI interface is presented in Figure 61. Each wind turbine icon or colored dot on the map is representative of one 2 km by 2 km block. The icon colors represent the effective capacity factor of each block for a Vestas V90 wind turbine at a height of 100 meters as shown in Table 5.

Table 5 - Legend for NREL Wind Potential Map Capacity Factors

Icon Color	Wind Potential Capacity Factor
Blue	< 25%
Green	25 – 30%
Yellow	30 – 35%
Orange	35 – 40%
Red	> 40%

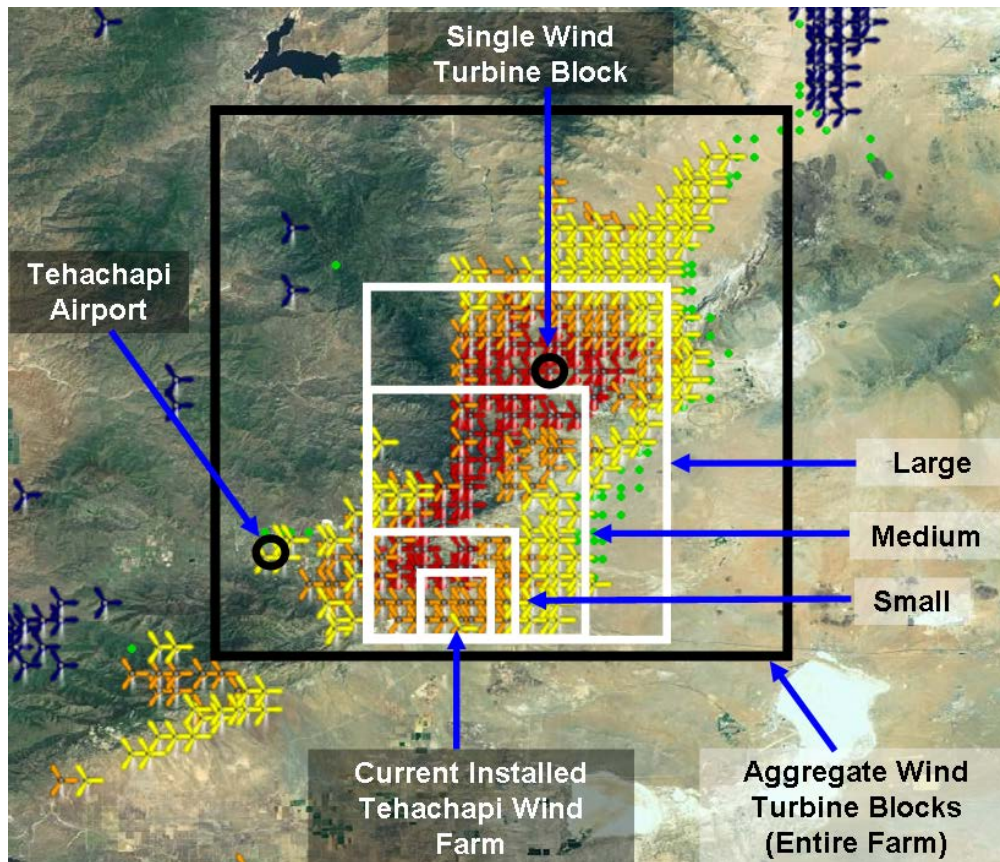


Figure 61 - NREL Wind Farm Potential Map in the Tehachapi region of Southern California

Data from the NREL model was obtained and uploaded into a SQL data server, where it was extracted by applying SQL database queries. One example of such a query was used to effectively calculate the sum of the power output from every turbine block confined to a user-specified set of spatial coordinates (latitude and longitude). This approach allows the user to obtain wind power data for different sizes of wind farms within the potential map or for the entire potential map itself, allowing the evaluation of wind power characteristics as a function of farm size. In addition, simple mathematical operations such as calculating the mean and standard deviation of each wind turbine block were also implemented using an SQL query.

The use of this dataset allowed the synthesis of wind power profiles of different spatial scales, capturing an important aspect of modeling wind power on the transmission grid from a dynamic

energy balancing perspective. The wind power output and severity of power fluctuations exhibited by a single wind turbine or small group of tightly clustered wind turbines is significantly higher than that exhibited by a large, spatially diverse group of turbines. An example of wind power profiles composed from data representing different scale measurements is presented in Figure 62 and Figure 63:

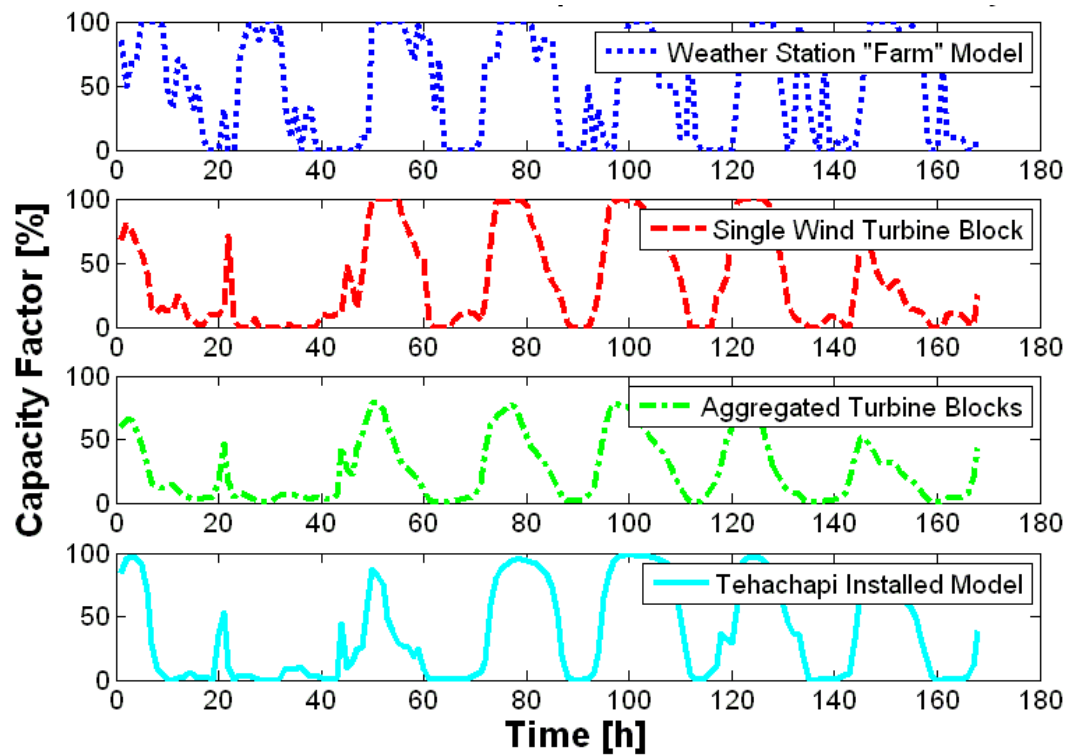


Figure 62 - Power profiles of different wind farm representation: 4th week of July 2005

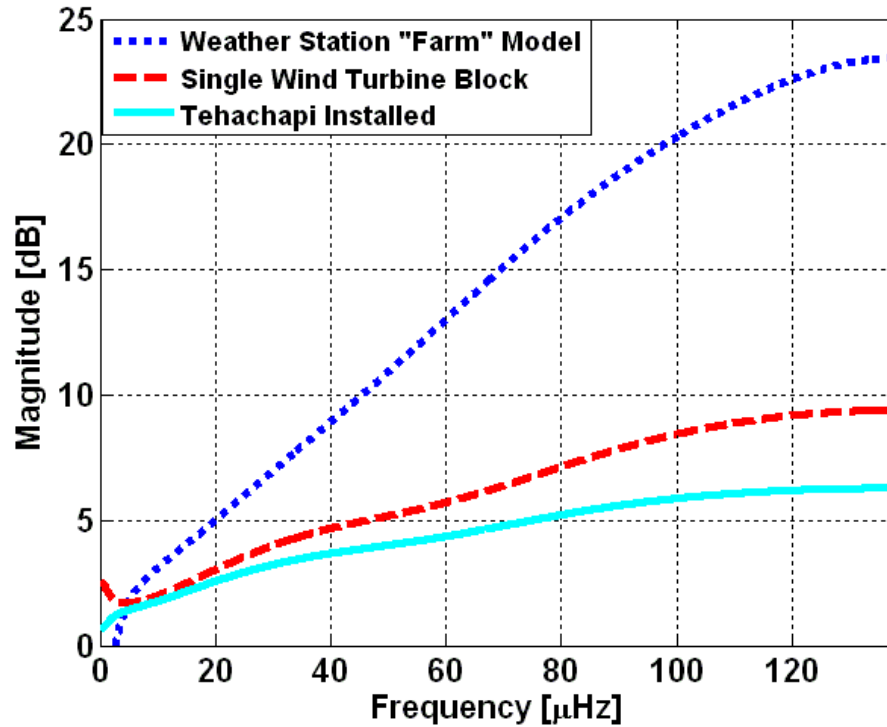


Figure 63 - Corresponding Power Spectral Density Relative to Aggregated Turbine Block Model

Four different scales of wind power measurements were compared:

1. A wind farm subject to measured wind speeds from the Tehachapi airport weather data (single point) using the Vestas V90 Power curve
2. A single wind turbine block (10 simulated turbines)
3. The currently installed Tehachapi wind farm (small simulated wind farm)
4. Aggregated wind turbine blocks (large simulated wind farm), as shown in Figure 61.

From Figure 63, it is apparent that wind power output determined from data measured at smaller scales yield more severe power dynamics than that determined from large-scale data. This is due to the buffering effects of the rotational inertia of the turbine and the finite time required for a prevailing wind disturbance to propagate or affect the total output of a wind farm covering a large land area. A separate, power spectral density-based analysis examined and confirmed the

presence of these effects, and the use of this particular dataset allows these characteristics to be taken into account when creating wind power profiles for the HiGRID model.

Wind power data was also obtained for different geographical regions, allowing the evaluation of wind power characteristics as a function of regional dispersion, allowing the use of decoupled wind power profiles to create aggregate wind power profiles in addition to simple scaling of power output. Total wind power profiles created in this manner are believed to be more representative of the actual wind power profile that will be imposed onto the transmission grid since wind power potential from different regions is likely to be utilized.

In the HiGRID tool, the total nameplate capacity of wind farms installed in different regions is specified as an input, and the resulting time-resolved power profile (MW vs. time) is calculated and produced from computation of the wind data.

4.1.2.1.2. Wind Data Verification

Wind power results from this model were verified against wind power production data from the currently installed Tehachapi wind farm as shown in Figure 64 and Figure 65. Data was provided by Southern California Edison [125] for the month of April 2005 as presented by the solid lines. The modeled wind profile which encompasses the currently installed wind farm is dubbed the “Tehachapi installed model”, and is based upon the known areas of wind turbine installations and estimates of wind turbine sizes and dispersion in this region as coupled to the NREL 2 km X 2 km wind data [124]. Model results are presented as dashed lines for the representative days (Figure 64) and average diurnal profiles (Figure 65). The Tehachapi installed model well represents the daily production from April, 2005 and the average diurnal profile [126] for the month of July 2005. In addition, the current analyses considered the entire Tehachapi area wind

resource as represented by the “Tehachapi Farm Model” curve, and shown for comparison in Figure 65.

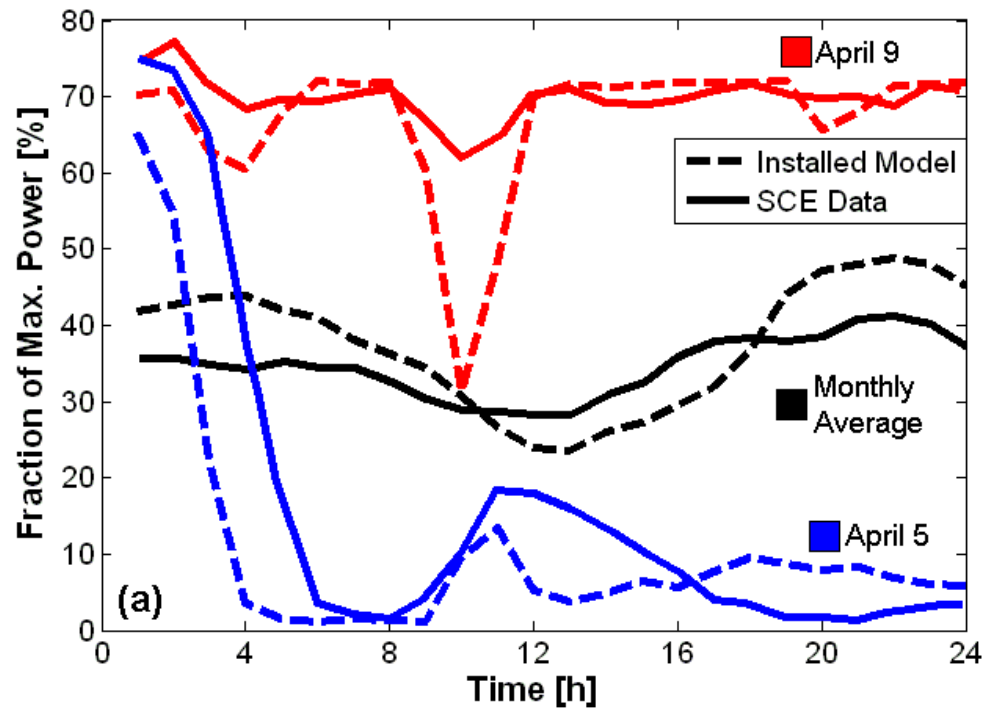


Figure 64 - Current Wind Power Model Verification with Tehachapi Wind Farm Power Data for April 2005

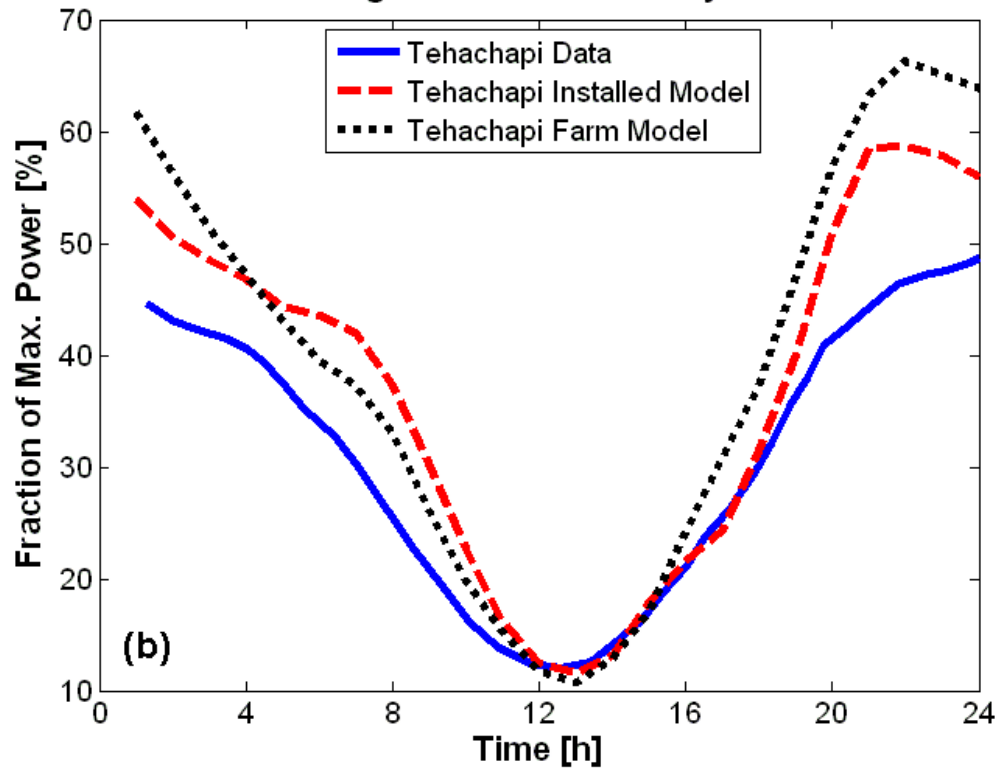


Figure 65 - Current Wind Power Model Verification with Tehachapi Wind Farm Power Data for July 2005

The Tehachapi installed model well simulates the average measured power production profiles, sharing the same qualitative characteristics and shape. Wind power is lowest during the day and peaks during the early morning and late night hours. However, the predicted average diurnal profile has higher capacity factors during the peak hours and lower capacity factors during the daytime hours than the SCE data. This trend is displayed to a reduced extent for the July 2005 results of Figure 65. This discrepancy is most likely due to differences between the wind turbine units assumed in the model and the actual wind turbine units currently used in the Tehachapi Wind Potential region. The model determines power output using the power curve of the Vestas V90 3.0 MW turbine, which is larger than most of the currently installed units. The currently installed units exhibit significant variation due to the diversity of wind turbine units from various manufacturers. The various cut-in speeds of the installed turbines compared to the single higher cut-in speed of the Vestas turbine lead to the more dynamic model responses to wind speed

(especially for low wind velocity) compared to the data. The rated speed of the Vestas turbine is about 15 m/s, which is generally higher than that of the installed turbines allowing modeled power to take advantage of the higher wind speeds at night, explaining the higher nighttime capacity factor of the model.

The model is also not expected to exactly predict the data due to other factors not considered in the model such as the diversity in the technology level of the currently installed wind turbines and wider variations in hub height (100 m in the model versus 60-100 m in the data).

Nonetheless, Figure 65 the figures present comparisons of wind power measured and predicted for two days in the year 2005, April 5 and April 9 that adequately verify essential intermittencies, day-to-day variability, dynamics and ramp-rate features of wind power in this region are captured.

4.1.2.2. Solar Photovoltaic Power Modeling

Solar power includes both photovoltaic and solar thermal technologies. For solar photovoltaic technologies radiation data from the NSRDB were selected for different sites in California including: 1) coastal sites like Santa Ana, Santa Maria and Miramar, 2) desert sites like Daggett-Barstow, Palm Springs, Twenty-nine Palms and Edwards Air Force Base, and 3) inland sites like Bakersfield Meadows and China Lake. Transmission and resource restrictions are considered in a similar manner as that for wind generation. Technologies include fixed plate, 1-axis tracking and two-axis tracking photovoltaic panels.

4.1.2.2.1. Solar Data Acquisition

For the purposes of the HiGRID code, solar power production is modeled by utilizing radiation data obtained from the National Solar Radiation Database (NSRDB) developed by NREL as inputs to first-principles-based models of solar photovoltaic panels and solar thermal power

cycles. The dataset includes the different components of radiation (direct, diffuse) and is converted into an effective total (in-plane) radiation via an in house radiation model. Data from the NSRDB is available for most sites from 1991 through 2005. The database contains hourly-resolved radiation measurements from a variety of sites spread throughout the U.S, as shown in Figure 66:

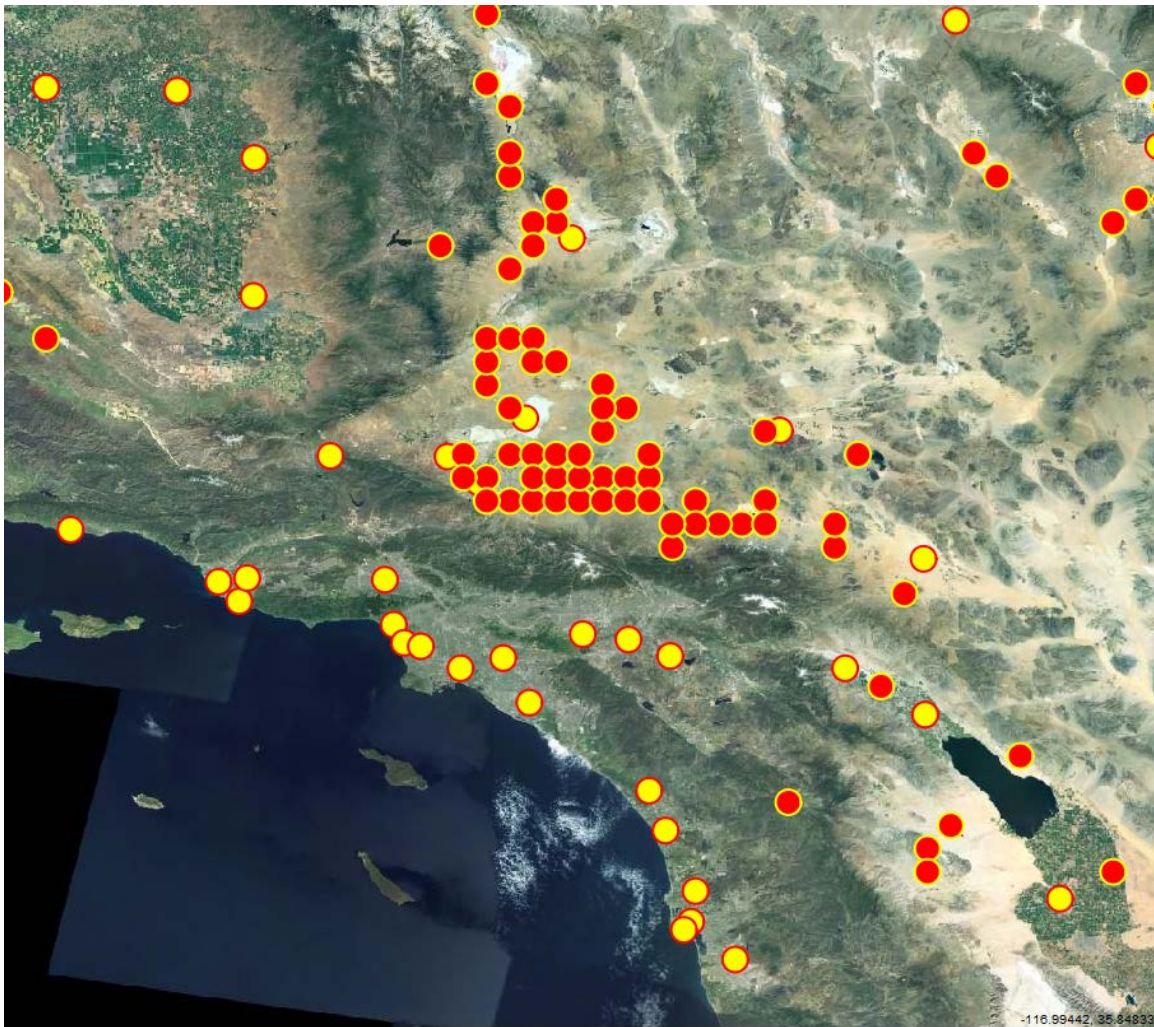


Figure 66 - Location of NSRDB Solar Radiation Measurements (Yellow)

A separate, in-house analysis [72] showed that for solar power profiles composed of a large amount of solar farms that are spaced apart by a sufficient amount such that their cloud-pass sequences are decoupled, the fast-timescale fluctuations in radiation become a smaller and

smaller fraction of the total solar power output and the total profile converges towards its longer-timescale average. This effect is presented in Figure 67 utilizing radiation data with a 5-minute resolution for the case of a) 1 site, b) 3 sites, c) 5 sites, and d) 8 sites spread across the state of Oregon, respectively.

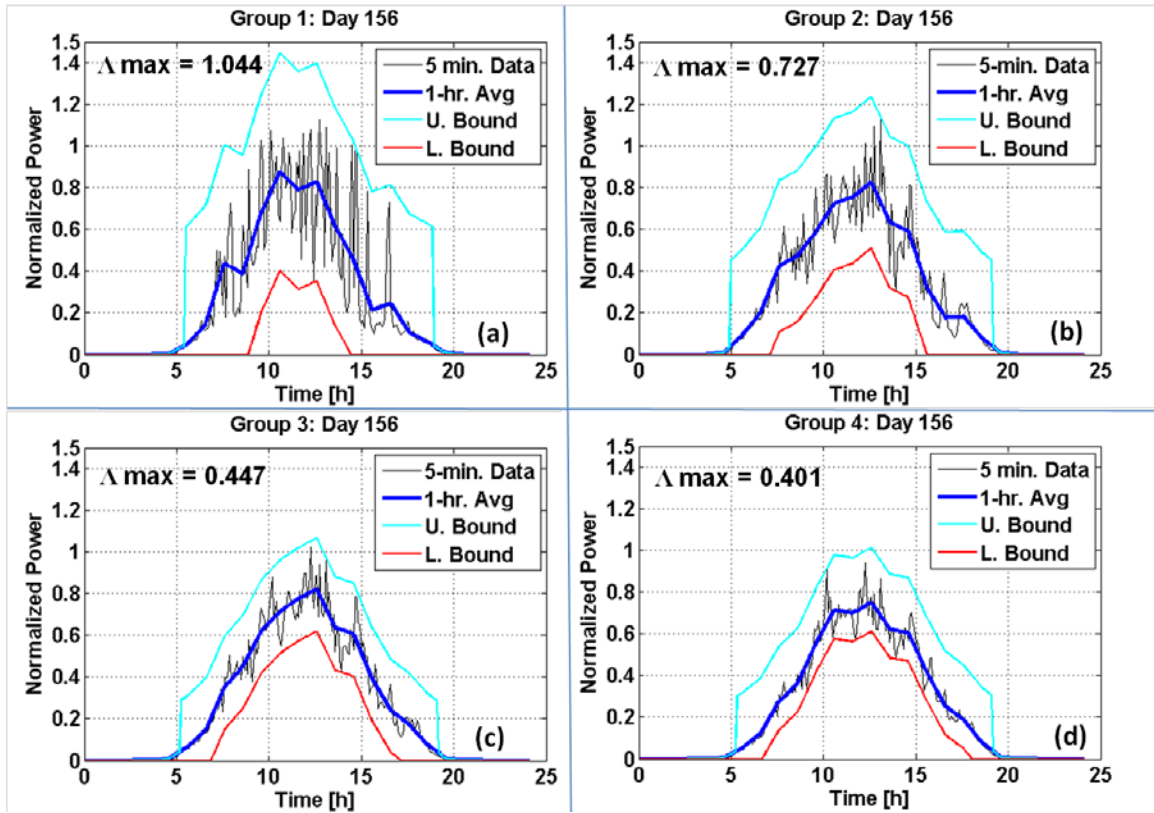


Figure 67 - Decrease in Magnitude of Fast-Timescale Fluctuations in Radiation Profiles based on a) 1 site, b) 3 sites, c) 5 sites, d) 8 sites

Therefore, for a large-scale system such as the transmission grid that utilizes multiple solar farms that are spread across large distances, it is reasonable to utilize hourly resolved radiation data as the input to model solar power production.

The use of this dataset allows for the construction of aggregate solar power profiles from solar farm installations that may be present at a variety of sites ranging from large desert installations to distributed coastal installations such as the rooftops of buildings. In the HiGRID code, the

nameplate capacity of solar farms at different sites is specified as an input, and appropriately scaled profiles from the different regions are combined to create the aggregate solar power profile. Different technologies such as fixed-plate, 1-axis tracking, and 2-axis tracking can be specified for each individual solar farm, and the different technologies utilize slightly different power profiles produced by in-house models.

4.1.2.2. Solar Radiation Module

Solar photovoltaics are capable of producing electric power from both direct and indirect light inputs. Therefore, the total radiation that is incident on the photovoltaic cell must be calculated from the different radiation components.

Calculation of the in-plane radiation on the solar array is done using the exact model constructed in Heling [127]. The model reads files containing hourly data for different types of solar insolation for a given location:

Direct “beam” insolation (B) is the component of the sun’s radiation which arrives on a horizontal surface at ground level without interruption, in a straight line from the sun.

Indirect “diffuse” insolation (D) is the component of the sun’s radiation which arrives at a horizontal surface at ground level after being reflected from atmospheric objects such as clouds and airborne particles.

An additional given parameter is the global horizontal radiation (H), which is the amount of total (beam and diffuse) radiation striking a horizontal surface at ground elevation.

The model uses the different types of insolation to calculate in-plane beam radiation (I_b), the in-plane diffuse radiation (I_d), and the in-plane radiation that is reflected from the ground. (I_r). The total in-plane radiation on the solar panel is then:

$$I = I_b + I_d + I_r$$

The in-plane beam radiation is calculated according to the following method using the solar declination and the true solar time:

The solar declination, which is the angle between the earth's equatorial plane and a straight line drawn between the center of the earth and the center of the sun, is calculated for locations north of the equator as:

$$\delta = 23.45^\circ \sin \left[\frac{360(d_n + 284)}{365} \right]$$

where d_n is the serial number of the day of the year.

The true solar time, which is the difference between noon and the considered hour of the day in terms of a complete revolution of the earth, is calculated as:

$$\omega = 15 \times (TO - AO - 12) - (LL - LH)$$

where TO is the local time, AO is the time by which the clocks are advanced ahead of local time zones, LL is the longitude of the site in consideration, and LH is the reference longitude of the local time zone encompassing the site in consideration. Note that TO and AO are in hours, and LL, LH are in degrees.

The solar declination and true solar time are used to calculate the angle of solar incidence θ_s , which is the angle between the sun and the line that perpendicular to the face of the photovoltaic array:

$$\begin{aligned} \cos \theta_s = & \sin \delta \sin \phi \cos \beta - \sin \delta \cos \phi \sin \beta \cos \alpha + \cos \delta \cos \phi \cos \beta \cos \omega + \dots \\ & \cos \delta \sin \phi \sin \beta \cos \alpha \cos \omega + \cos \delta \sin \alpha \sin \omega \sin \beta. \end{aligned}$$

where Φ corresponds to the latitude of the site under consideration,

The total in-plane beam radiation is then calculated by:

$$I_b = B \max(0, \cos \phi_s)$$

The total in-plane reflected radiation can also be calculated by:

$$I_r = \rho_g H \frac{1 - \cos \beta}{2}$$

where ρ_g is the reflectivity of the ground.

The in-plane diffuse radiation is calculated according to the model presented by Perez (Perez, 1990), represented by:

$$\theta_z = \cos \phi \cos \delta \cos \omega + \sin \phi \sin \delta$$

$$I_d = D \left[\frac{(1 - F_1)(1 + \cos \beta)}{2} + F_1 \frac{a}{b} + F_2 \sin \beta \right]$$

Where F_1 and F_2 are functions of the sky condition, found from tables presented by Perez [128], and θ_z is the solar zenith angle as calculated by Duffie [129]. The values for a and b are calculated according to:

$$a = \max(0, \cos \theta_s)$$

$$b = \max(0.087, \cos \theta_z)$$

4.1.2.2.3. Fixed-Plate Solar Photovoltaic Module

The PV model captures the effect of solar irradiance, cloud cover, and ambient temperature on the array outlet power, dynamically capturing the variable nature of solar PV power. The model integrates (1) a power equivalent circuit model and (2) an energy balance based PV cell temperature model. The developed model is tuned to represent experimentally measured data of a Solarex MSX-60 panel installed on top of the Engineering Laboratory Facility at the University

of California, Irvine. The developed module model output is scaled to simulate any sized solar installation parametrically.

Power module

The model was developed based on an equivalent circuit representation of a solar cell as presented in Walker, 2001, with temperature dependence of the diode saturation current (I_o) and photo-current (I_L), and the inclusion of a series resistor. The circuit diagram is presented in Figure 68.

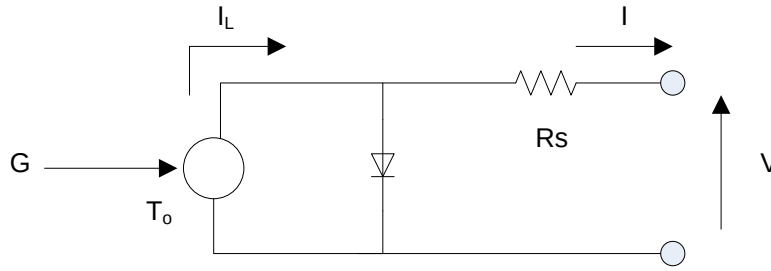


Figure 68 - Equivalent Circuit Representation of a Solar Cell

The operating current throughout the panel circuit is determined from the Shockley diode Equation and Kirchoff's current Law:

$$I = I_L - I_o(e^{q(V + IR_s)/nkT} - 1)$$

The limiting current of the panel is assumed to have a linear temperature dependence, where the slope is determined from the short circuit current at different temperatures:

$$I_L = I_{L(T_1)}(1 + K_o(T - T_1))$$

$$K_o = (I_{SC(T_2)} - I_{SC(T_1)})/(T_2 - T_1)$$

The reference limiting current is assumed to have a linear dependence on the magnitude of the incident solar radiation:

$$I_{L(T_1)} = G \cdot I_{SC(T_1, \text{nom})} / G_{(\text{nom})}$$

The diode saturation current is dependent on temperature and is given by:

$$I_o = I_{o(T_1)} \cdot (T / T_1)^{3/n} \cdot e^{-qV_g / nk \cdot (1/T - 1/T_1)}$$

$$I_{o(T_1)} = I_{SC(T_1)} / (e^{qV_{oc}(T_1) / nkT_1} - 1)$$

Where the variables are as follows:

Table 6 - Power Module Variables

Variable	Quantity	Value	Units
I	Operating Current	--	A
I _o	Diode Saturation Current	--	A
I _L	Photo-current	--	A
T	Temperature	--	K
T ₁	Reference Temperature	298	K
G	Radiation	--	W m ⁻²
R _s	Series Resistor	0.003	Ohm
I _{SC}	Short Circuit Current	3.8	A
K _o	Slope of Current vs. Temperature curve	--	A/K
V _{OC}	Open Circuit Voltage	0.585	V
q	Charge	--	C
n	Diode Quality Factor (1 < n < 2)	1.2	--
V _g	Band Gap Voltage	1.12	V
k	Boltzmann's Constant	1.38 x 10 ⁻²³	J K ⁻¹
V	Operating Voltage	--	V

Cell Temperature Module

The temperature of the solar cell was determined by applying conservation of energy to a control volume encompassing the entire reference solar array. Heat transfer due to convection and

radiation was resolved, however conduction was assumed to be negligible since the contact area of the panel interconnects with the roof is very small.

$$\rho \forall C_v \frac{dT_s}{dt} = Q_{\text{rad}} - Q_{\text{conv}} - Q_{\text{rad,loss}} - W$$

Convective heat transfer was determined using a turbulent-flow Nusselt number approach for a flat plate:

$$\overline{\text{Nu}} = \frac{\bar{h}L}{k_f} = 0.664 \text{Re}_L^{0.5} \text{Pr}^{0.33}$$

Where Re_L is the Reynolds number of the ambient flow, Pr is the Prandtl number, k_f is the thermal conductivity of the ambient air, L is the length of the plate, and A_s is the surface area of the array.

The density, dynamic viscosity, thermal conductivity and Prandtl number are all temperature dependent. The velocity of the ambient air is taken from measured wind speed data in the Santa Ana region for the appropriate time period.

Radiative heat transfer was modeled using the grey body assumption, where the temperature of the grey surface is set to the ambient temperature:

$$Q_{\text{rad}} = (G_{\text{measured}} - \varepsilon \sigma (T_s^4 - T_\infty^4)) A_s$$

where G_{measured} is the in-plane solar radiation on the panel, calculated from the radiation module.

In addition, a radiative heat loss was included to account for the absorptivity of the ambient atmosphere and any cloud cover that might be present. This loss is also modeled with a grey body, where the temperature of the grey body is set to the ambient temperature minus 2 degrees

Kelvin, and the emissivity of the grey body is dependent on the ambient relative humidity and cloud condition:

$$Q_{rad,loss} = \varepsilon(\%RH, \text{Cloud}) \sigma A_s (T_s^4 - (T_\infty - 2)^4)$$

Where:

$$\varepsilon(\%RH, \text{Cloud}) = 1 - \left(\frac{\varepsilon_{RH} + \varepsilon_{Cloud}}{2} \right)$$

Where ε_{RH} and ε_{Cloud} are the emissivity indices of the grey surface due to relative humidity and cloud cover, respectively:

Table 7 - Relative Humidity Emissivity Indices

Relative Humidity (%)	Relative Humidity Index
RH < 65%	0
65% < RH < 70%	0.1
70% < RH < 75%	0.25
75% < RH < 80%	0.4
80% < RH < 85%	0.5
85% < RH	0.8

Table 8 - Cloud Condition Emissivity Indices

Cloud Condition	Cloud Condition Index
Clear	0
Few	0
Scattered	0.05
Broken	0.25
Overcast	0.65
Haze	0.8

This approach greatly simplifies the calculations needed to determine the temperature of the solar cell. Notice that as the cloud cover or relative humidity increases, the radiation loss decreases, representing the effects of atmospheric radiation absorption and re-radiation. This assumption was made since it was deemed unnecessary to develop a physics of weather simulation for the purpose of determining the temperature of the solar cell, since the variation in the performance of the cell over the temperature range considered is relatively small, however it is significant enough to be included.

4.1.2.2.4. Fixed Plate Photovoltaic Model Verification

The model was constructed to simulate the performance of a Solarex MSX60 60W solar panel array. Model validation of the power module was carried out by comparing simulation results to power data obtained from a 3.85 kW solar array on the rooftop of the Engineering Laboratory Facility at the University of California, Irvine. The simulated radiation and cell temperature were used as inputs to the power module, and the results were compared to the measured power data. The individual 60W panel was scaled up to 3.85 kW for comparison.

The combined model was validated against measured power, cell temperature, and radiation data from a 3.85 kW solar panel array on the roof of the Engineering Laboratory Facility at the University of California, Irvine.

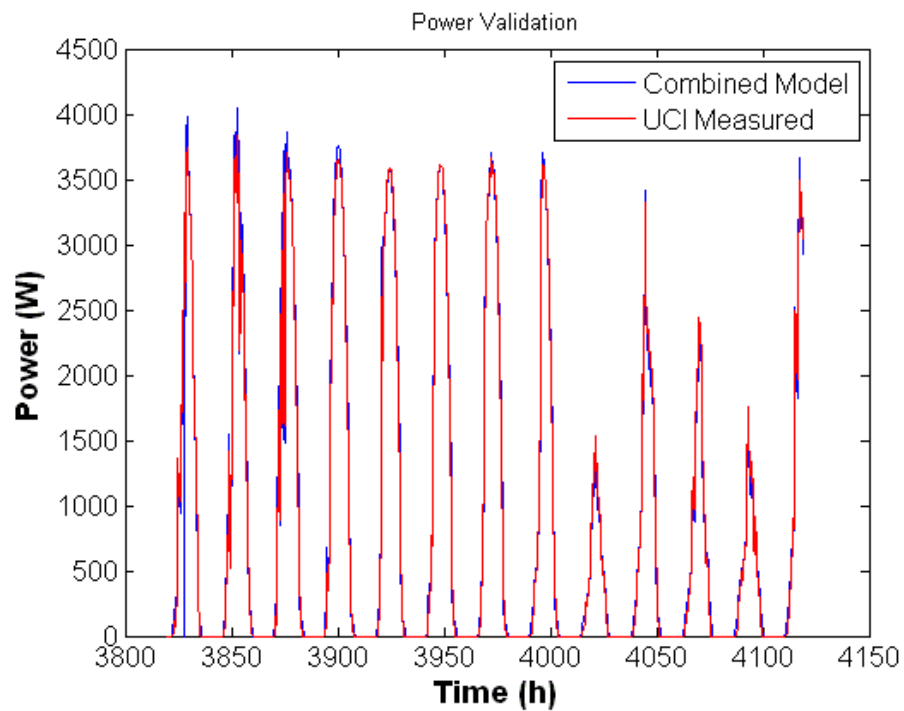


Figure 69 - Solar Model Validation: Power Module

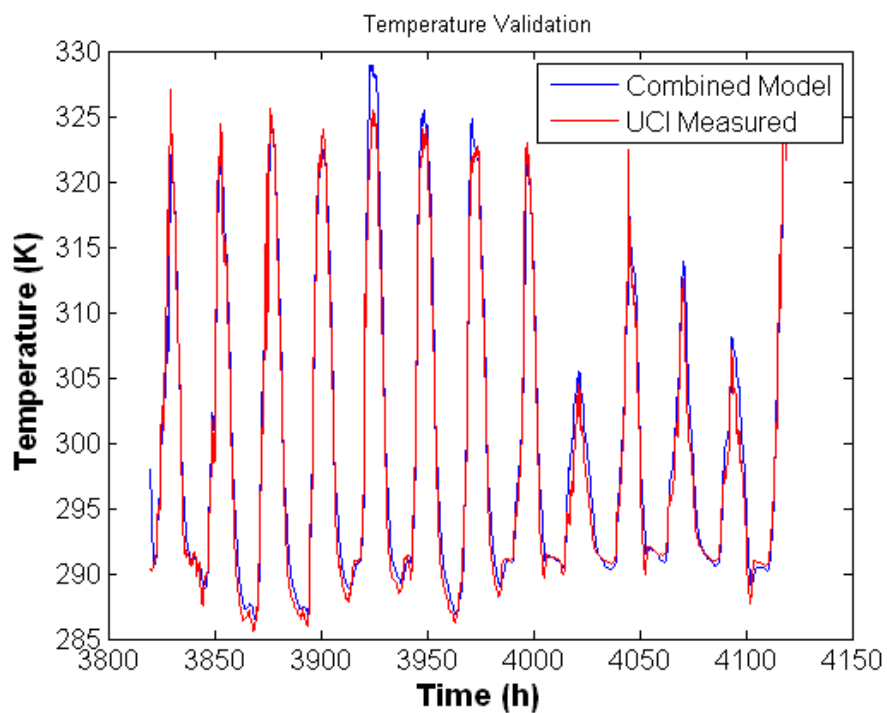


Figure 70 - Solar Model Validation: Temperature Module

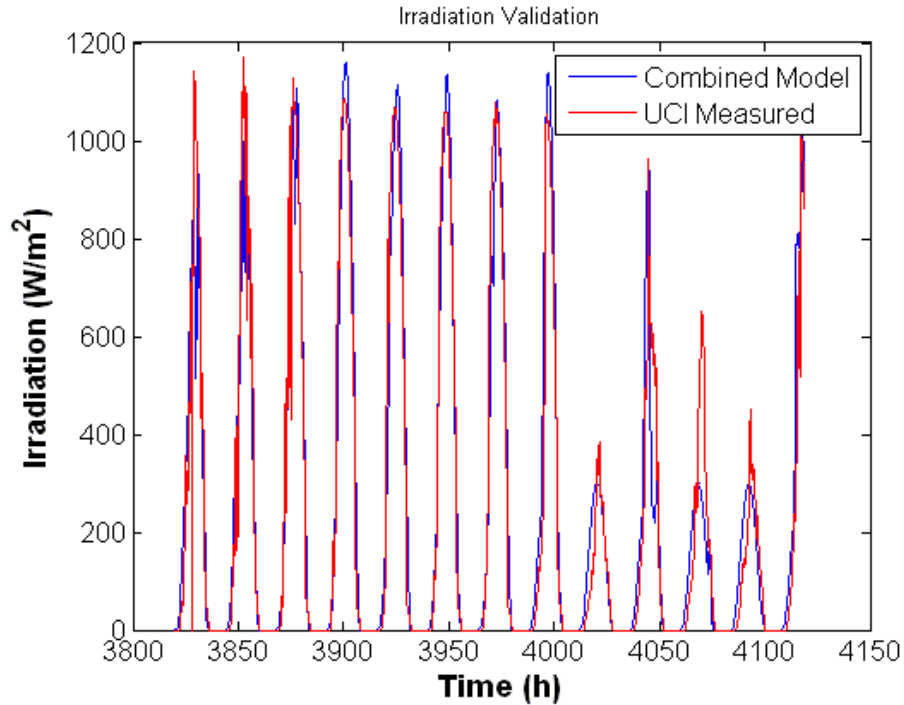


Figure 71 - Solar Model Validation: Radiation Model

From Figure 69, Figure 70 and Figure 71, the combined model results match with the measured data with an average error of 1.36%. Therefore, it is safe to assume that a more detailed model for determining the effective radiation, power output, or cell temperature is not necessary for this level of analysis.

4.1.2.2.5 Azimuth/Tilt-Tracking Solar Photovoltaic Module

In order to simulate the performance of tracking solar photovoltaic systems, which are likely to be deployed in areas with high solar radiation and large amounts of open land area such as the desert for potential increased performance benefits, a model of an angle tracker has been developed and applied to the fixed PV model previously described. This is applied to azimuth (1-axis) and tilt (2-axis) tracking systems. The process for the azimuth angle tracking is described here, however, the exact same algorithm is used for the tilt angle.

The azimuth angle, which is an input to the radiation module, is varied via a controller which attempts to optimize its value such that the maximum solar power output is obtained for a given time step and corresponding conditions. The azimuth angle is a spherical coordinate which is measured as the difference from a reference vector on the plane of the horizon and another vector that represents the projection of an object's location onto the plane of the horizon, as presented in Figure 72:

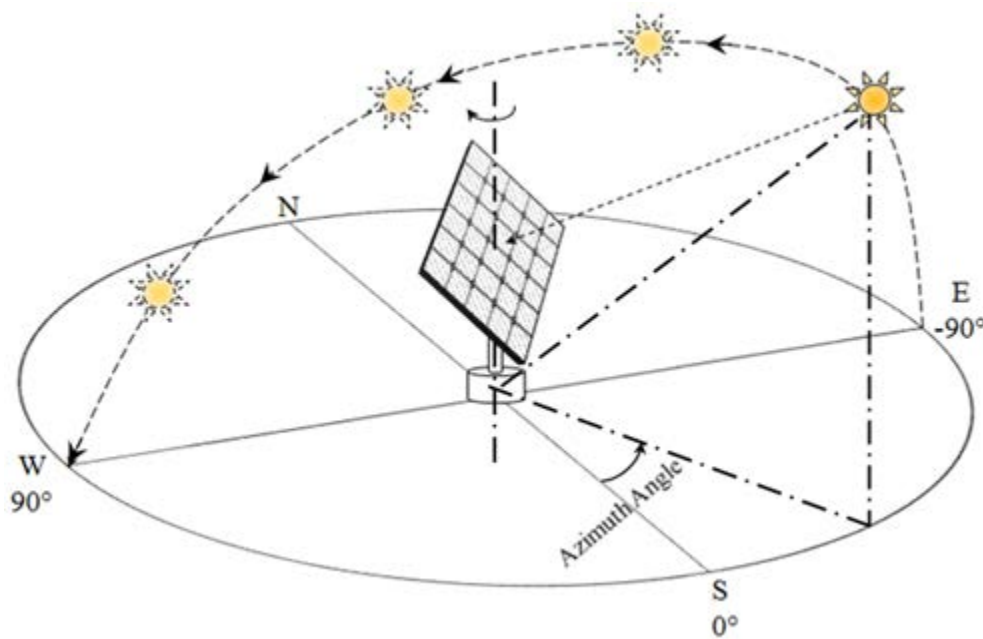


Figure 72 - Azimuth Angle with a Southward Reference Vector

The controller varies the input azimuth angle to the radiation module by the use of a feedback control law which measures the power output of the system at three different azimuth angles for each iteration: the default azimuth angle for the current iteration and an azimuth angle slightly higher and slightly lower by fixed increments than the default azimuth angle for that iteration. The model compares the angles via error signals. If the default azimuth angle yields the highest power output, the azimuth angle remains at that value and the model progresses to the next time step. If the default azimuth angle does not yield the highest power output, the default azimuth

angle is changed to the value (slightly higher or slightly lower) of that which yielded the higher power output out of the three cases, and that value is used for as the default azimuth angle for the next iteration, where the process is repeated. This process is repeated until an iteration step is reached where the default azimuth angle produces the highest power output, after which the model progresses to the next time step. Schematically, the control law is presented in Figure 73, with an example comparison of power output with fixed PV in Figure 74:

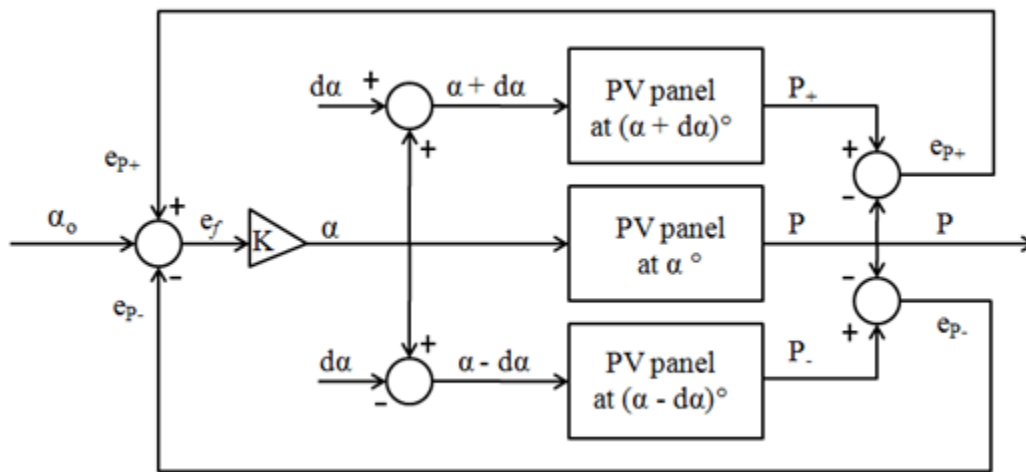


Figure 73 - Control Law for Azimuth Tracking PV Module

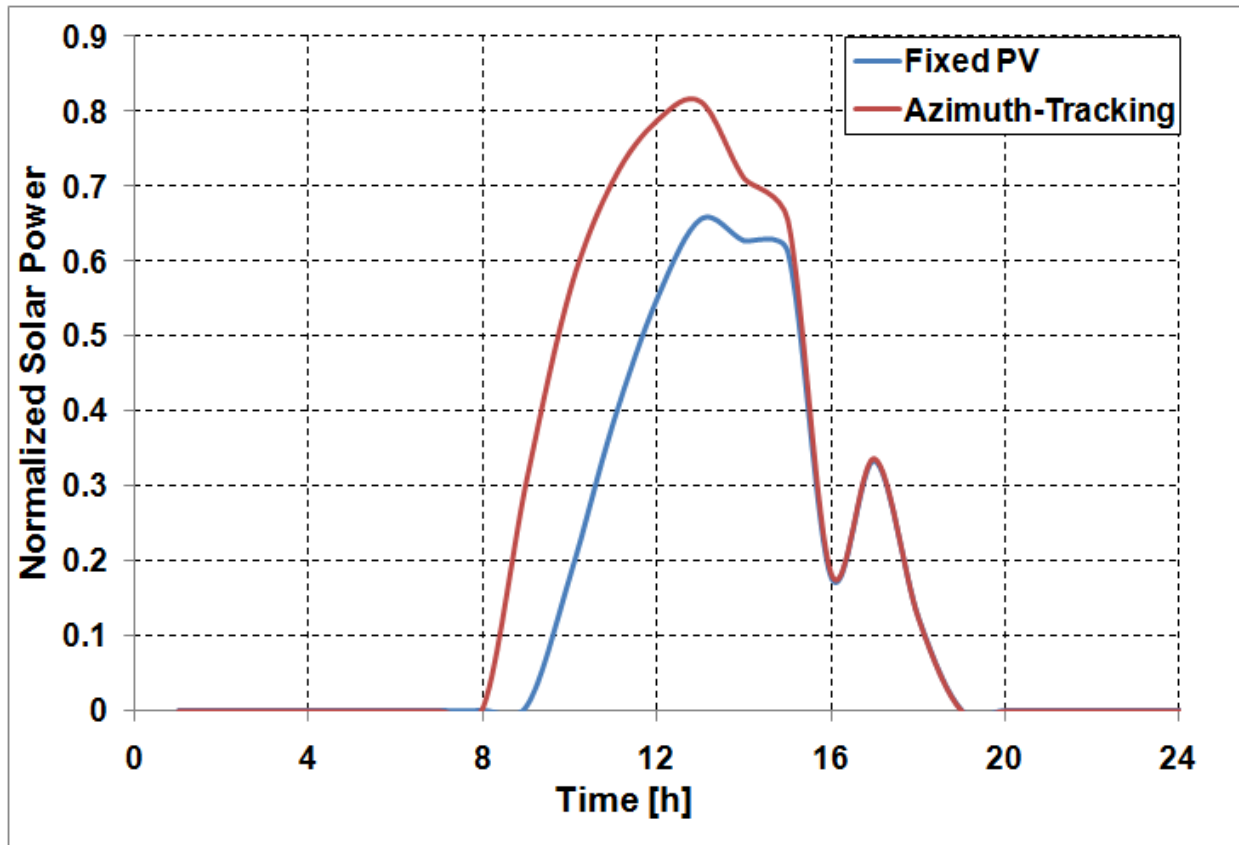


Figure 74 - Comparison of Azimuth Tracking and Fixed PV Power Outputs

The results are site dependent, however, overall the azimuth tracking PV module displayed higher power output, energy obtained, and capacity factors compared to that exhibited by the fixed PV model.

4.1.2.3. Solar Thermal Power Modeling

Additionally, a single-axis tracking solar thermal power plant is modeled. The system is modeled after the Solar Energy Generation Systems (SEGS) VIII plant in Harper Lake, California. The solar thermal power plant model was developed in the Matlab/Simulink environment and uses a different tracking model than the solar photovoltaic plants for determining the incident radiation. This was deemed necessary since solar thermal power plants can only take advantage of direct solar radiation. A model was developed to calculate the power generation of a solar thermal system. The selected plant architecture is based on the SEGS VIII

solar thermal power plant, which uses a trough to concentrate the sun's energy onto a tube that delivers the heated working fluid to a heat exchanger. Heat is then drawn from the heat exchanger to power a steam turbine, which can also use natural gas to raise steam for the turbine. This model is based on the thesis of Robert Bialobrzeski [130].

Solar thermal power generation relies on the concentration of solar radiation to heat a fluid that is used by a heat engine to generate electricity. The concentration of sunlight is required to reach temperatures sufficient for use in a heat engine. Three mirror configurations for the concentration of sunlight are commonly considered: parabolic trough, parabolic dish and heliostat with central receiver.

Table 9 - Comparison of the different concentrating solar thermal power technologies

Concentrating Solar Thermal Technology	Tracking	Concentration ratio	Operating temperature (C)
Linear Fresnel reflector	Single-axis tracking	10 - 40	60 - 400
Parabolic trough collector	Single-axis tracking	10 - 80	60 - 400
Parabolic dish reflector	Two-axis tracking	600 – 1300+	100 - 1500
Heliostat field collector	Two-axis tracking	300 – 1000+	150 – 600+

The parabolic trough and heliostat systems have been demonstrated at large scales in California and Nevada. The parabolic trough system accounts for the largest solar installation in the world: the Solar Energy Generating System (SEGS). This installation consists of nine separate arrays installed in California totaling 354 MW of capacity. However, an installation currently under

construction in Ivanpah Dry Lake, CA using the heliostat technology will surpass the SEGS with a 370 MW installed capacity. Although the efficiency of a parabolic trough system is the lowest of the three concentration technologies, it is the specific technology modeled for the assessment of solar thermal power in HiGRID given that most concentrating solar thermal power is currently generated in California using the parabolic trough technology.

Table 10 - Summary of the SEGS installations

Unit	I	II	III	IV	V	VI	VII	VIII	IX
Solar Field Aperture Area (hectares)	8.3	19	23	23	25.1	18.8	19.4	46.4	48.4
Rated Capacity, MWe	13.8	30	30	30	30	30	30	80	80
Annual Net Electricity Production (GW-hr)	30.1	80.5	91.3	91.3	99.2	90.9	92.6	252.8	256.1

The parabolic trough model focuses on one of the larger SEGS installations, SEGS VIII. SEGS VIII has a peak capacity of 80 MW (89 MW when supplemented with natural gas) and began operation in 1989. The solar field consists of many loops of several solar collector assemblies (SCAs) connected in series (See Figure 75). Each of these loops are connected in parallel, and the heat transfer fluid (HTF) in the supply/return headers to each loop is maintained at a nominal temperature such that the temperature difference across each loop is the same. When the HTF returns from the field it enters several heat exchangers, which produce steam for the steam turbine. After steam production, the HTF then returns to the field. The HTF is Therminol-VP1. The heat exchanger configuration in SEGS VIII consists of a pre-heater, a steam generator, and a super-heater. The steam produced in these heat exchangers expands through a steam turbine. When steam exits the turbine, it is condensed and sent back through the heat exchangers. The heat exchangers, steam turbine, and condenser are referred to as the power block of the system.

In HiGRID, the solar thermal power model was developed based on modeling work done by Bialobrzeski [130]. Bialobrzeski developed this model to investigate the cost effectiveness of SCA replacement throughout the solar field given that expensive, high efficiency SCAs may not be cost effective in the lower temperature regions of the SCA loops. With this motivation in mind, simple, empirical models were developed for computationally efficient simulation of the entire solar field and the power block. A model such as this will work well for use in HiGRID given its computational efficiency.

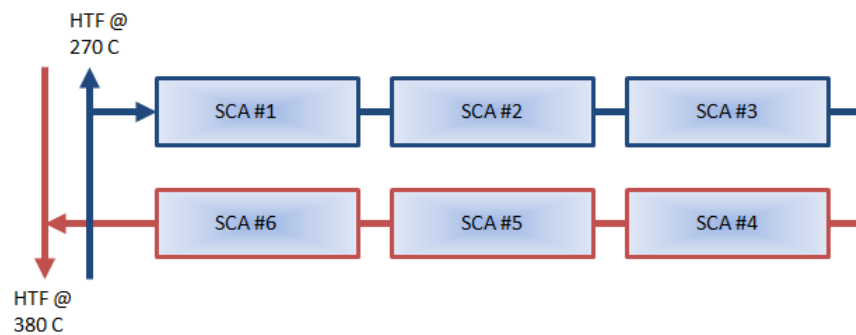


Figure 75 - Schematic of the SCA loop within the solar field

4.1.2.3.1. Angle of Incidence

The incident solar radiation will result only from direct beam radiation because of the high concentration ratio in parabolic troughs. It can be determined from the angle of incidence for a north-south axis orientation with single axis east-west tracking. The angle of incidence was determined using the following equations:

$$\omega = 15 (\text{solar time} - 12)$$

$$\delta = 23.45 \sin\left(360 \frac{284 + \text{day}}{365}\right)$$

$$\text{solar time} = \text{time} + 4 (\psi_{ST} - \psi) + EOT$$

$$EOT = 229.2 (0.000075 + 0.001868 \cos B - 0.032077 \sin B \\ - 0.014615 \cos(2B - 0.04089 \sin 2B))$$

$$B = (\text{day} - 1) \frac{360}{365}$$

$$\theta = \cos^{-1} \left(\sqrt{1 - (\cos \alpha - \cos \alpha (1 - \cos \gamma))^2} \right)$$

where $\alpha = 90 - \theta_z$ and $\theta_z = \cos^{-1}(\cos \delta \cos \omega \cos \psi + \sin \delta \sin \psi)$

If $\sin \omega > 0$ then

$$\gamma = 2\pi - \cos^{-1} \left(\frac{\cos \psi \sin \delta - \cos \delta \cos \omega \sin \psi}{\cos \alpha} \right)$$

otherwise

$$\gamma = \cos^{-1} \left(\frac{\cos \psi \sin \delta - \cos \delta \cos \omega \sin \psi}{\cos \alpha} \right)$$

Table 11 lists the symbols used in the equations above along with their corresponding meanings.

Table 11: Angle of incidence equation parameters

α	Solar Altitude
ϕ	Latitude
ψ	Longitude
γ	Solar Azimuth
ψ_{PST}	Time Zone Reference Longitude

The incident radiation can then be determined using the angle of incidence using the following equation:

$$\dot{G}_{inc,rad} [W/m^2] = I_b \cos \theta$$

4.1.2.3.2. Solar Field Model

The solar field model considers a single loop within the field to be representative of the rest. It also assumes the temperature distribution in the loop is linear such that an equivalent temperature rise occurs in each SCA. The thermal energy collected per unit aperture area is calculated using the following equation:

$$\dot{G}_{coll} [W/m^2] = X_{end} \eta_{opt} \dot{G}_{inc,rad} - f_{HL} (C_1 \Delta T + C_2 \Delta T^2)$$

where

$$\eta_{opt} = f_{opt} C_{off-axis} \eta_{opt,nom} - f_{\theta} \theta \left(\frac{1}{\cos \theta} - 1 \right)$$

$$X_{end} = 1 - \frac{f}{L_{SCAstring}} \tan \theta$$

$$\Delta T = T_{HTF} - T_{ambient}$$

T_{HTF} is the average of the inlet and outlet temperatures of each SCA in the loop, determined by assuming a linear temperature distribution across the loop. Given that there are 6 SCAs in each loop, there will be a temperature rise of 18.5 C across each SCA in the loop when the header temperatures are 271 and 382 °C. Table 12 defines the variables used within the equations for determining the thermal energy collected by the solar field.

Table 12 - Definition of variables for solar thermal power model

$L_{SCAstring}$	Length of Loop	571.2	m
f	Focal Length	1.71	m
$\eta_{opt,nom}$	Nominal optical efficiency	0.733	-
C_1	Sandia Linear Heat Loss Coefficient	0.05145	W/m ² -K
C_2	Sandia Quadratic Heat Loss Coefficient	0.00069	W/m ² -K
$C_{off-axis}$	Off-axis Correction Coefficient	1	-
f_{θ}	Incidence Angle Modifier	0.004	-
B_{const}	Gross Power Constant	-13.1995	MW
C_{coeff}	Gross Power Coefficient	0.381957	-
D_{const}	Net Power Constant	0.119574	MW
F_{coeff}	Net Power Coefficient	0.917813	-
Loops	Number of Loops	142	-
A_{SCA}	SCA aperture area	548.4	m ²
f_{opt}	Optical Efficiency Modifier		-
f_{HL}	Heat Loss Modifier		-
θ	Incidence Angle		-
X_{end}	End Effect Coefficient		-

The optical and heat loss modifiers are determined using a vector that defines the value for each heat collection element (HCE) type and a matrix that defines the percentage of a specific HCE type (e.g., broken, cloudy, washed, etc.) at each of the six SCA locations within the loop. The transpose of the column vector in Table 13 can be multiplied by the matrix in Table 14 to determine the appropriate optical and heat loss modifiers at each SCA in the representative loop. The matrix used for model verification against experimental data is displayed below in Table 14.

Bialobrzeski (2007) does not explicitly state what percentages he assumed, therefore, the values used within this report could be different. The values in Table 14 were chosen such that there is agreement between experimental data [130] and the model predictions. It is important to note that for the HiGRID simulations the matrix in Table 14 was altered to resemble a completely new plant, i.e., values of 1 were placed in the last row of Table 14.

Once the thermal energy collected by a single loop is calculated, it can then be multiplied by the total number of loops (142) to determine the total thermal energy collected by the solar field.

Table 13 - Optical and heat loss modifiers for the various heat collection element (HCE) types considered

HCE type	f_{OPT}	f_{HL}
Broken	1	6
Cloudy	0.43	3
Washed	0.5	2.5
Lost Vacuum	0.98	2.1
Refurbished	0.91	2.3
Used Luz	0.98	1.9
New UVAC	1.03	1.5

Table 14 - Fraction of each heat collection element (HCE) type in each location of the SCA loop

	SCA # in loop					
HCE type	1	2	3	4	5	6
Broken	0.1	0.1	0.1	0.1	0.1	0.1
Cloudy	0.05	0.05	0.05	0.05	0.05	0.05
Washed	0.05	0.05	0.05	0.05	0.05	0.05
Lost Vacuum	0.1	0.1	0.1	0.1	0.1	0.1
Refurbished	0.1	0.1	0.1	0.1	0.1	0.1
Used Luz	0.6	0.6	0.6	0.6	0.6	0.6
New UVAC	0	0	0	0	0	0

4.1.2.3.3. Power Block Model

The power block is modeled using curve fits to data collected from the SEGS VIII plant. It was found by [130] that the gross power output could be defined by the following equation:

$$\dot{E}_{gross} = B_{const} + C_{coeff}\dot{Q}_{total}$$

The net power output can then be calculated from the gross power output using this equation:

$$\dot{E}_{net} = D_{const} + F_{coeff}\dot{E}_{gross}$$

The coefficients in the above equations are defined in Table 12.

4.1.2.3.4. Natural Gas Use

Natural gas is used to supplement the heat collected by the solar field only during on-peak periods. The on-peak period is defined as 12pm to 6pm on weekdays from May 12 to September 28 [130]. During these on-peak periods, natural gas will be used to attain the target on-peak gross power output of 97 MW with the constraint that the maximum thermal energy production of the natural gas heaters is 200 MW. The total target thermal energy production is determined using the following equation:

$$\dot{Q}_{tot,target} = \frac{\dot{E}_{gross,target} - B_{const}}{C_{coeff}}$$

Once the target thermal energy production is defined, the total thermal energy to be produced from the natural gas heaters can be defined:

$$\dot{Q}_{gas} = \dot{Q}_{tot,target} - \dot{Q}_{field}$$

The total thermal energy provided to the power block is then:

$$\dot{Q}_{total} = \dot{Q}_{gas} + \dot{Q}_{field}$$

The rate at which the natural gas heaters can change output is set to 35 MW (increase or decrease) per hour.

4.1.2.3.5. Model Verification

The model described in the previous sections was verified against SEGS VIII operational data presented by [130]. The data include annual net power generation, natural gas usage, and solar heat collected as well as diurnal variation for a full week in the summer from July 2, 2005 to July 9, 2005. The data are presented in Figure 76 along with model predictions. The model seems to agree reasonably well in spite of two major issues. The first is that in the model natural gas is used on day 185 when in the data natural gas usage is shown to be zero. This is a result of the model's inability to account for holidays, which will introduce some error into the annual results that should be negligible. The other major issue is that the model's natural gas use begins after the time that the data suggest it should, and in the evening the model's natural gas use continues after the data suggest it should have been shut down. After further examination, it can be proposed that although the on-peak period is from 12pm to 6pm, the operators may begin turning the gas heaters on an hour before the on-peak period started in order to allow them time to warm up before the on-peak period begin. Similarly for shutdown, the operators likely begin shutdown before the on-peak period ended to account for the max ramp rate of the gas heaters.

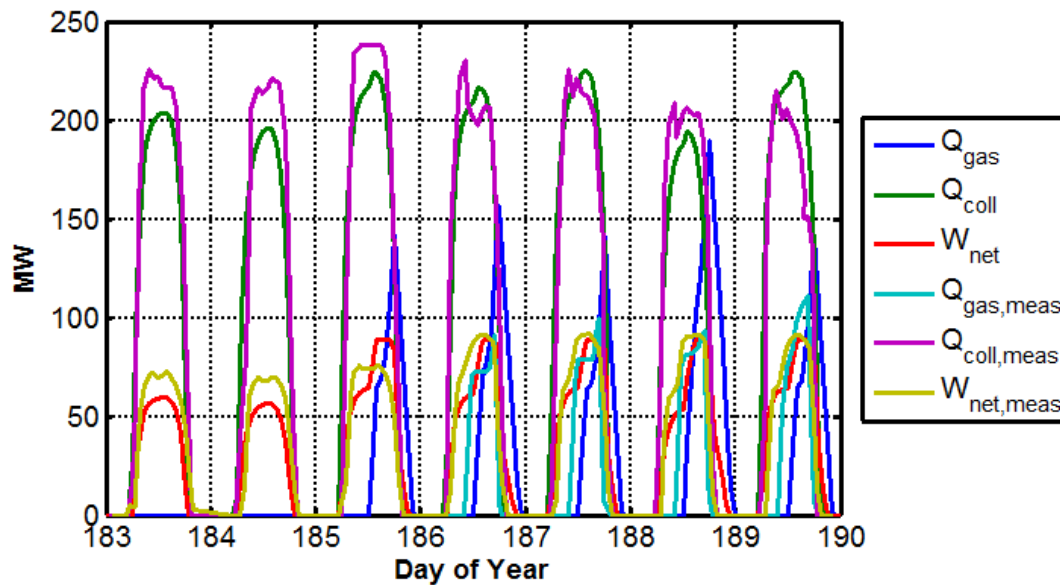


Figure 76 - Comparison of model predicted performance to SEGS VIII measured data from Bialobrzieski [130]

Based on data from Figure 76 regarding the gas heater operation schedule, the operation schedule in the model was modified such that the gas heaters would begin start-up and shutdown an hour prior to 12pm and 6pm, respectively. The model results and the corresponding SEGS VIII plant data are shown in Figure 77. After modifications to the gas heater schedule, the model's predictions of the actual plant performance improved. The model predicts the dynamics of a parabolic trough solar thermal power plant reasonably well and is sufficient for use in HiGRID.

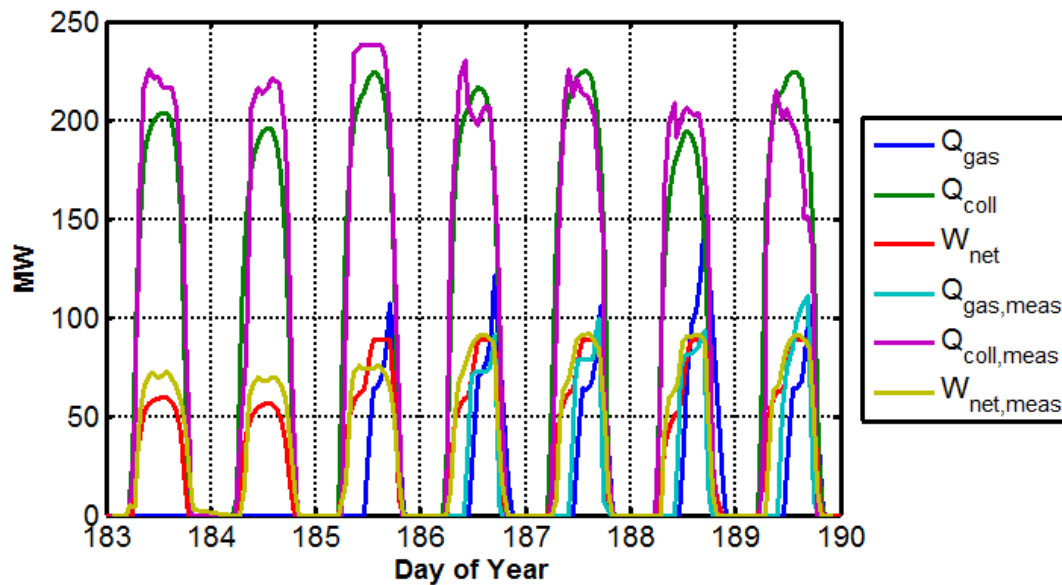


Figure 77 - Comparison of model predicted performance after modifications to the gas heater operation schedule to SEGS VIII measured data from Bialobrzeski [130]

The model was also compared to the annual data available from the SEGS VIII plant. The weather and solar radiation data used for input into the model were obtained from NREL's 2005 National Solar Radiation Database [131]. The location used was Daggett-Barstow, which is about 25 miles from the SEGS VIII site in Harper Lake, CA. Table 15 shows the comparison between the model's prediction of annual plant performance with the annual data collected from the SEGS VIII plant. The solar field heat collection is well predicted, which is expected because the matrix in Table 14 was tuned to achieve this result. Additionally, the net power output still well predicts the plant's power output for 2005 in spite of the error associated with the gas heaters.

Table 15 - Comparison of model predicted annual plant performance for 2005 with annual SEGS VIII plant data

	Model	Measured	% Error Model
Net Electric Power (MW-hr)	141,474	138,212	2.36%
Total Field Heat Collection (MW-hr)	452,809	438,605	3.24%

4.1.2.3.6. Solar Thermal Power Plant Model

The model used for the simulations in HiGRID differs from the model used for verification in that the HiGRID simulations model approximates a new plant which uses new HCEs in all the SCAs (See Table 16). These new HCEs are universal vacuum collectors (UVAC) as identified in Table 13. This new plant will be more suitable for use in the HiGRID simulations where the grid impacts of new renewable energy installations are considered.

Table 16 - Fraction of each heat collection element (HCE) type in each location of the SCA loop for the solar thermal power plant for use in HiGRID

	SCA # in loop					
HCE type	1	2	3	4	5	6
Broken	0	0	0	0	0	0
Cloudy	0	0	0	0	0	0
Washed	0	0	0	0	0	0
Lost Vacuum	0	0	0	0	0	0
Refurbished	0	0	0	0	0	0
Used Luz	0	0	0	0	0	0
New UVAC	1	1	1	1	1	1

4.1.2.4. Other Renewables

Geothermal, biomass, biogas and small-hydro generation are also considered in HiGRID. When assessing impacts of renewables on large communities and on the entire state, it is important that these other renewables be considered.

4.1.2.4.1. Geothermal

Geothermal plants exhibit a relatively constant output as is evidenced from the data provided by FERC for 2000 and 2001 [132]. Monthly capacity factor-based operation is used to incorporate planned outages. Dry steam, flash steam and binary cycle power plants are available technologies and can be selected for analysis with each plant type introducing unique operation and cost parameters. Based on estimates from the California Energy Commission, estimates for geothermal capacity in addition to current levels range from 4 to 4.825 GW [133, 134].

4.1.2.4.2. Small-Hydro

In California, hydroelectric generation is only considered renewable if it does not introduce diversion or require increased appropriation of water, as defined by Senate bill 1078 [135]. This means that only a portion of the total hydroelectric generation is considered renewable. HiGRID determines this portion based on the historical state generation percentage of total hydroelectric. The details of hydroelectric generation will be discussed in the “Dispatchable Load Module” section. Limits are placed on small hydropower capacity potential based on a report by the California Energy Commission [65].

4.1.2.4.3. Biomass and Biogas

Biomass and biogas are included as renewable resources. On the state-level there is very little in-state coal generation, therefore it is assumed that all of the biomass and biogas is used as fuel for advanced combined cycle power plants. HiGRID captures CO₂ impacts of using biomass and biogas. Combustion of biomass or biogas will reduce the CO₂ emissions in comparison to burning natural gas since the combustion of those fuels has a low net CO₂ impact.

For California, estimates for the waste mass input into state landfills and wastewater treatment plants was obtained from the UC Davis biomass facilities database [136] and use of the EPA Landfill Gas Emissions Model (LandGEM) [137] to determine the annual potential production of

biogas in the state. Biogas is assumed to be methane production from anaerobic digesters at landfills and wastewater treatment plants. The facilities operating during the year 2005 were used as representative, to be consistent with all of the other datasets used in this analysis. Using these resources, the total potential amount of biogas production in the state for the corresponding year was determined, and is presented in Table 17:

Table 17 - California Annual Biogas Potential for 2005

<u>Parameter</u>	<u>Value</u>
Annual Potential Biogas Production	2,757,782 Metric Tons
Annual Biogas Potential Energy Equivalent	134.3294 Million MMBTU

Biogas is applied to displace natural gas usage as much as possible in all cases, provided that the natural gas consumption is high enough. Biogas can be used both for displacing power plant fuel or feedstock for steam methane reformation, and is assumed to be carbon neutral.

4.1.3. Dispatchable Load Module

Dispatchable loads refer to any technology that is able to artificially affect the shape or magnitude of the electric load demand. The HiGRID model includes technologies such as dispatchable hydroelectric power, energy storage, demand response, electric vehicle charging, and hydrogen production via electrolysis. A description of the hydroelectric, energy storage, and demand response models are presented here, whereas a description of the grid interface of electric vehicle charging and hydrogen production will be presented in detail in the description of the Light-Duty Transportation Sector modeling efforts.

4.1.3.1. California Specific Models

The dispatchable load module for the California model includes generation that supports system balancing and must be calculated before the balance generation. Dispatchable loads include

hydroelectricity, energy storage, demand response and electric vehicle charging. Each of these technologies affects the generation or demand in a unique way.

The dispatchable load module compares the load demand with the available renewable generation and then dispatches to complement the renewable generation and improve general grid performance. Time-resolved load demand data are drawn from CAISO's OASIS site [138] and are scaled to reflect total California demand [139]. Managing ancillary services requires that sufficient capacity be available to meet the load and to adjust in the event of a generator failure or a sudden reduction in demand. This effectively creates a margin of operation for each power plant that is considered in this module. The time-resolved ancillary services (spinning reserve and regulation) values are drawn from OASIS and scaled just as the load vector was scaled to reflect statewide demand as opposed to in-state generation. While it is assumed that spinning reserve will remain constant over the course of a single year even with increasing renewables, regulation requirements will change with increasing renewable penetration. Using values from CAISO's Integration of Renewables Resources report, regulation is increased proportionally according to the profiles shown in Figure 78 with increasing renewable penetration [78].

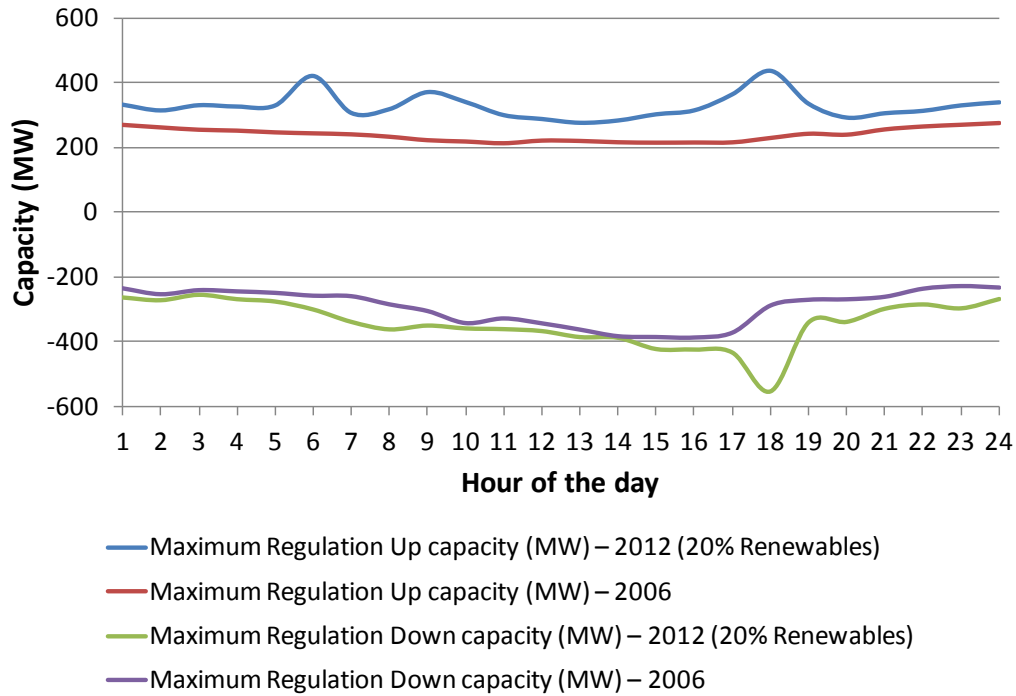


Figure 78 - Effect of Increasing Renewable Mixture on Regulation Up and Down [78]

4.1.3.2. Hydroelectric Generation Module

In California, hydropower generation provides a significant amount of dispatchability to the grid given its ability to quickly increase and decrease generation. From Table 22 and Table 23 it can be seen that conventional hydroelectric (HY) combined with Hydroelectric Pumped Storage (HYPS) contributes over 70% of the spinning reserve capacity, over 60% of the non-spinning reserve capacity and nearly 40% of the regulation reserve while only contributing 15.8% to the generation capacity for 2000 and 2001.

Hydropower is modeled using several components including run-of-the-river, conventional hydro, daily hydro and pumped hydro and is scaled to the total hydro generation in California for the base case. Figure 79 depicts the methodology employed for the hydro model.

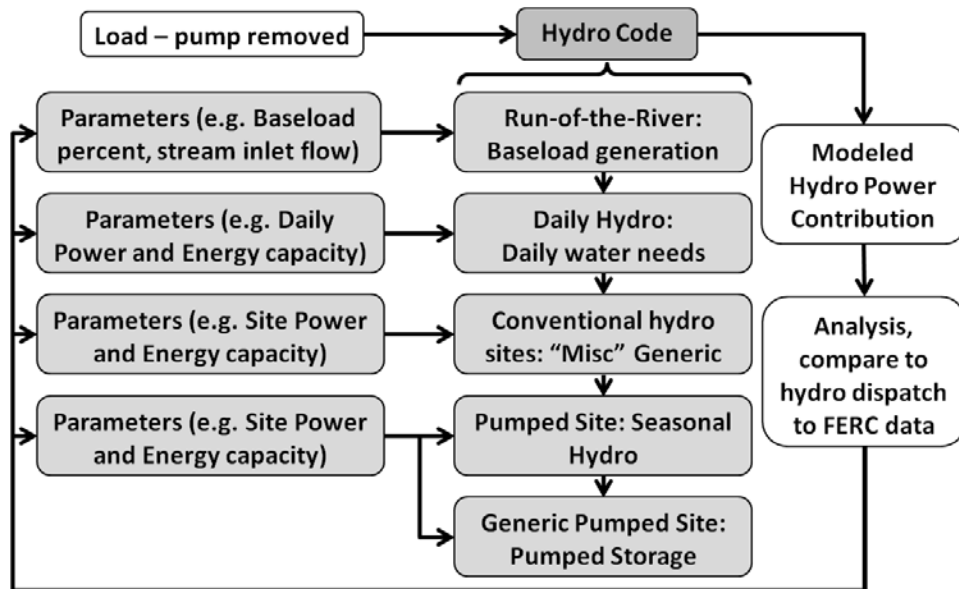


Figure 79 - Methodology for Hydroelectric Model

Conventional hydroelectric power (i.e., non-pumped hydro) is divided into seasonal hydro, daily hydro, and base load hydro. The aggregate of these sub-models represents the total conventional hydro power. Seasonal hydro refers to power generated from water to prevent flooding as a result of seasonal rain patterns. Daily hydro is water that is required to pass through on a daily basis to meet water supply needs, such as agriculture or human consumption. Base load hydro represents power generated from run-of-the-river hydro sites that generate electricity proportional to the flow of the river. Pumped storage resources are divided into the *seasonal* and *pumped* portions of pumped hydro. The seasonal portion of pumped hydro is the water that is dispatched through pumped storage turbines that accumulates from upstream flows and rain water for the same reason as conventional hydroelectric plants, such as water level regulation. The pumped portion hydro refers to the remaining capacity that can be pumped back up from the lower to the upper reservoir and be used to generate at a later time. All the categories for hydro modeling should not be considered as rigidly defined. For example, base load hydro may sometimes contain water that would be more properly defined as daily hydro. Rather, these

categories are implemented in the code to ensure that all the requirements are met by breaking the system down into smaller, more manageable components. The model was verified to hydro plant generation data released by the FERC during the Western Energy Crisis in 2000 and 2001 [50]. Hourly resolved data for every in-state hydro plant participating in the energy market was collected for this dataset. Based on the models created using 2000 and 2001 data the hydro operation in 2005 can be predicted, as will be shown.

Two large power plants in California are selected to be explored in greater detail. Castaic Power Plant, located between Pyramid Lake Castaic Lake, and Helms Power Plant, located northeast of Fresno. Stream flow data for both sites were obtained from the United States Geological Survey (USGS) Annual Water Data Reports. By using stream flow data, evaporation losses are included in the analysis.

To calculate the energy resulting from the stream flow, the pressure head, efficiency, stream flow and other operating conditions must be known. Every site is different and not all are tracked by USGS sensors, which makes inclusion of this detail challenging when considering around 300 plants are in-state alone.

Since each site is supplied by a different inlet stream, each with unique time-resolved stream flow rates which are dependent on a number of meteorological factors, a representative inlet stream flow was used to represent the total flow from all rivers in California that lead to generation stations. This was achieved by using a combination of multiple stream flow data obtained from the USGS. Three different stream patterns were chosen to reflect the state-wide stream flow patterns. These rivers were chosen for their relatively large flow volumes and their potential contribution to the total generation within the state, as recorded in FERC's eLibrary.

The selected locations are the Feather River, the American River, and the Yuba River. The patterns for the three rivers are different on a yearly basis, for example, peak flow may occur in winter, while another year it occurs in summer. This is caused by a variety of factors, such as human use and regulations, rainfall, snow melt, evaporation and other losses. It is assumed that a combination of the three rivers yields a seasonal pattern that approximates the water input into the hydro energy system. Only the pattern is of concern here, as the magnitude is proportional to the total energy generation from hydro in the state (i.e., 18.9% of the total for 2005). Portioning of the combination was obtained through error minimization by comparing the modeled hydro dispatch with the actual generation data for the year 2001. The composition and the available maximum capacity for each stream were varied, and the lowest error result was used as a representative stream flow. Using this approach and aggregating the hydroelectric fleet alleviates the need to track each site's specific parameters such as pressure head, installed capacity, turbine efficiency, and reservoir size. As a result the pressure head is selected to ensure a representative energy stored per unit volume of water and all turbines were assumed to have identical efficiencies of 80% and the efficiency for pumped storage was set at 75% [140].

Four separate models exist: run-of-the-river hydro, daily hydro, seasonal hydro, and pumped hydro. The first two types of hydro generation behave similar to base load generation as there is little to no control over their operation. Run-of-the-river hydro generation is proportional to the stream flow vector. The daily hydro model ensures that there is a minimum of hydro generation each day. This value is selected based on the base load hydro and historical operation of hydro power plants. When the generation occurred is a function of the load profile to be met subject to generation ramp rate and installed generating capacity constraints. The most substantial contribution to conventional hydro power generation comes from the seasonal hydro model.

This category reflects large generating stations with reservoirs and how they must operate throughout the year. Consequently, this model must be run for an entire year to capture these properties. The model sequentially reduces the demand signal by bringing on additional hydro generation subject to system and generator constraints and starts with the output from the daily hydro and run-of-the-river models. In this way, base load constraints are integrated into the conventional hydro model. Additional constraints include an aggregated reservoir level (initial fill, final fill, minimum fill and maximum fill), provision for spinning reserve, fleet ramp rate and installed generation capacity. All reservoirs are modeled as one large reservoir from which water can be drawn to generate electricity. To address level constraints, the reservoir is converted from volume capacity to energy capacity using the following:

$$\frac{\dot{V}(t)}{\sum \dot{V}(t)} \cdot E_{Hy} = \dot{V}_{energy}(t)$$

Where $\dot{V}(t)$ is the time-resolved stream flow rate and E_{Hy} is the total electric generation from hydro for the concerned system (i.e., the state of California for this analysis). Then the level is constrained by first taking the vector of stream flows converted to energy and calculating the cumulative fill level, using the following:

$$V_{fill}(t) = \sum_1^t \dot{V}_{energy}(t)$$

and second by applying the following two equations as constraints:

$$\max(V_{fill}(t)) \leq V_{cap}$$

$$V_{fill}(t_{initial}) = V_{fill}(t_{final})$$

For the first equation, V_{cap} is a constant that represents the maximum system reservoir capacity.

This term is calculated by comparing with several years of historical data to determine how it

changes with changing values of E_{Hy} . The second equation is used to ensure that the level from one year to the next returns to its original level.

The hydro system is constrained to a maximum installed capacity value such that:

$$\max(P_{Hy}(t)) \leq P_{Hy \text{ Max}}$$

where $P_{Hy}(t)$ is the time-resolved conventional hydro generation signal and $P_{Hy \text{ Max}}$ is the maximum installed capacity. Spinning reserve capacity is subtracted from $P_{Hy}(t)$ thereby reducing the available capacity for dispatch. Additionally, the fleet ramp rate is applied during each incremental increase in generation as the model solves. The fleet ramp rate is a tuned parameter based on the hydro generation data from the 2000 and 2001 FERC data.

$$-R_{down} \leq \frac{d}{dt}(P_{Hy}(t)) \leq R_{up}$$

The last model is the pumped hydro model. This model reflects the behavior of pumped hydro generating stations and is comprised of two parts, the seasonal component and the pumping component. The seasonal model is the same as is used with conventional generation and allows for consideration of stream flows into the reservoir in addition to just pumping water from a lower reservoir. For the pumping model, generation is sequentially turned on and pumps required to offset the generation are turned on at a time before the generation is needed. Rather than depleting water from the reservoir, the model locates the nearest earlier local minimum value and raises the load at that time. By including the generation and pumping efficiencies (80% and 75%, respectively) the penalty associated with pumping the water to the upper reservoir and using it later is assessed. This process is repeated and subject to similar constraints as those used for the other models like reservoir level, fleet ramp rate and installed capacity of generators. Because there is an ability to pump, additional constraints on the pumps are included

like fleet ramp rate and installed pumping capacity. The majority of the data is drawn from the USGS in the form of daily volumetric flow measurements, in addition to general reservoir characteristics, such as size and height. The daily measurements had to be extrapolated into hourly data by assuming an average hourly value for each hour. Since the hydro model looks at the cumulative flow rate, this process was determined to be acceptable as will be shown from verification against both 2000 and 2001 FERC data. This data allowed for matching of both the general shape that hydro power should create as well as the total energy.

4.1.3.3. Hydroelectric Verification

Absolute percentage differences are calculated as a measure of the error. Using the absolute value ensures that signals that are less than the historical data being compared to do not skew the results. All values for percentage differences are presented as a percentage of the historical FERC signal.

$$\text{Percent Difference} = \frac{\sum |Model_{Signal} - FERC_{Signal}|}{FERC_{Signal}} \cdot 100$$

Hydro generator data was aggregated for 2000 and 2001 from the FERC data and used to verify the model results. The same model was used to compare both years with only three values changed, which include: 1) hourly-resolved load demand, 2) total yearly energy from conventional hydro and pumped hydro, and 3) normalized stream flow vector. While the amount of energy generated from hydro is strongly dependent on the weather for that year, the installed capacity stays relatively constant. According to the CEC in its power plant database [80], the installed capacity of hydro plants in California has risen less than 100 megawatts between 1994 and 2009, which represents a capacity increase of 0.667%.

Any hydro model must accurately represent different behaviors including, diurnal, as well as seasonal. That is why multiple criteria were considered when assessing the accuracy of the model. The four most important components are the hourly timeseries, daily average and monthly average. Hourly timeseries represents the hourly dispatch of both conventional and pumped generation. Daily average represents the average of each hour of the day for the entire year and captures the diurnal behavior. Lastly, the monthly average is the average power generation for each month and captures the seasonal behavior. Following the above equation, the absolute, percentage difference is calculated with comparison to the FERC data, and the results for 2000 and 2001 are shown in Table 18. Figure 80, Figure 81 and Figure 82 show the comparison between FERC hydro data and model runs for 2001 on an hourly basis, a daily average basis, and a monthly basis, respectively.

Table 18 - Percentage Differences Between FERC Data and Modeled Hydro for 2000 and 2001

	Hourly Timeseries	Daily Average	Monthly Average
FERC 2000	15.7%	11.5%	11.0%
FERC 2001	14.9%	6.2%	4.4%

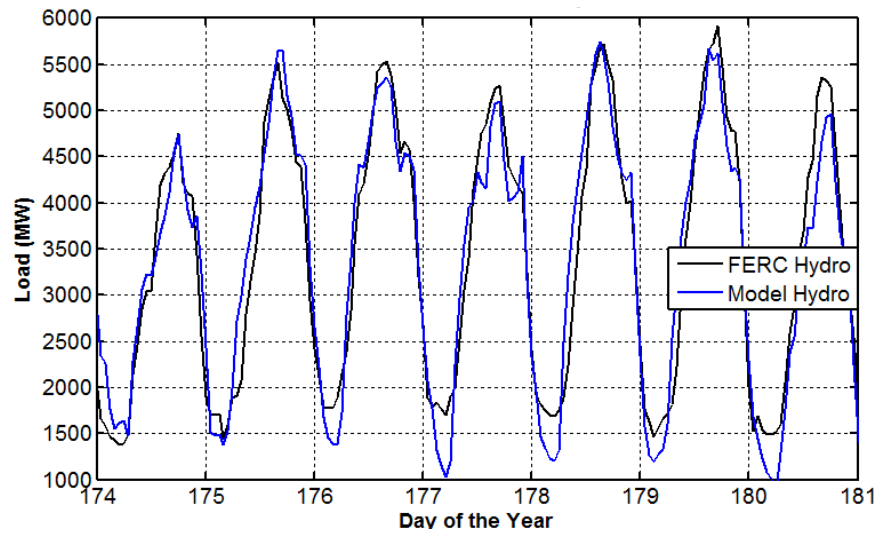


Figure 80 - Hourly Timeseries of Model and FERC Data in 2001

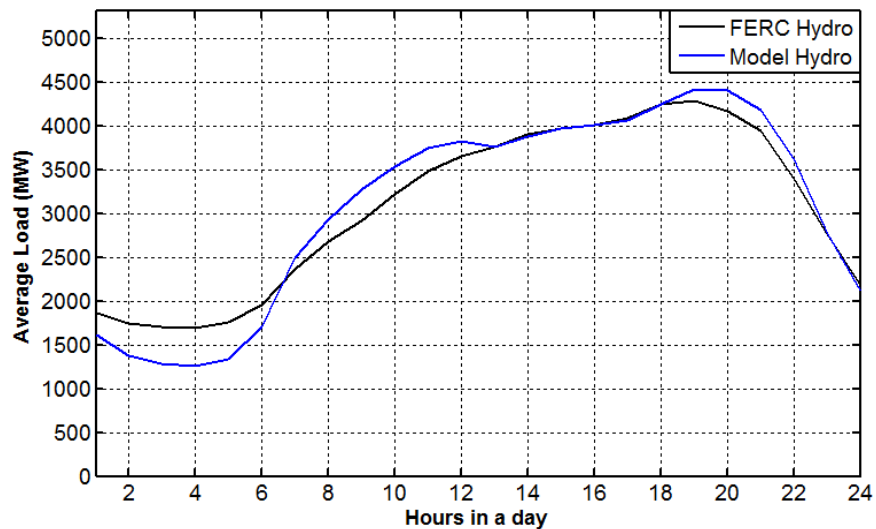


Figure 81 - Daily Average of Model and FERC Data in 2001

In comparison to FERC data, it can be seen the model tends to under-generate hydroelectricity during the night and early morning, predominantly between midnight and 7am. Additionally, past 7am there are higher than expected generation rates. Still, an error value below 15% on an hourly basis, paired with the decreased error when doing averaged comparisons, shows the model's potential to model other years.

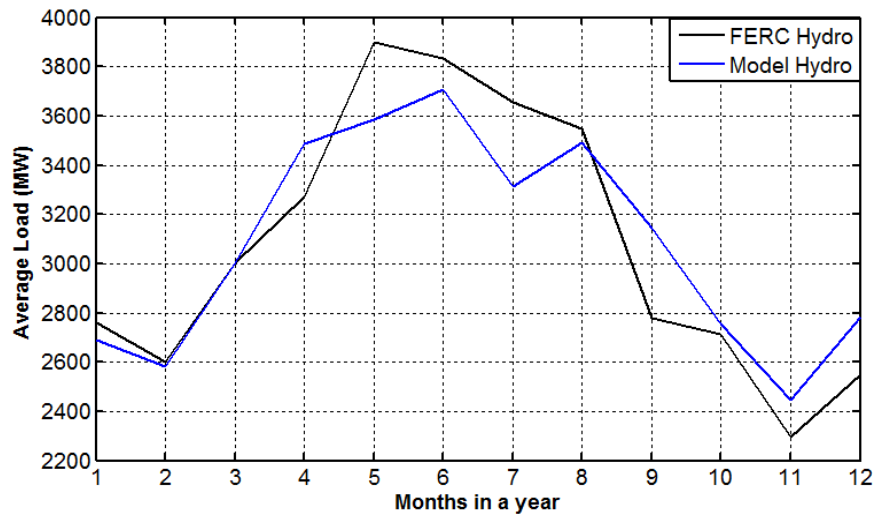


Figure 82 - Monthly Average of Model and FERC Data in 2001

Once the model was verified for different years it was adjusted to reflect 2005. The goal of this model is to represent how hydro generation can change with increasing renewables, and coincident renewable generation data for wind and solar is only available for 2005, thus the model must be able to function for any year. In the base case, HiGRID is designed for 2005 based calculations of similar reasons, and as such, uses 2005 CAISO load and spinning reserve profiles. Unlike the FERC data, which looks at only generators, the CAISO data represents the electricity demand, which includes the increase in demand from pumping for pumped hydro sites. A separate methodology was designed to remove this consumption from the CAISO demand profile and prevent duplication of pumped storage electricity consumption. This method, termed pump removal, uses a feedback loop to arrive at the corrected load profile.

The feedback loop starts with the original load profile passing through the hydro code. The modified load profile was passed through the hydro code, and pumped storage energy consumption from the load balancing process could be output. Theoretically, adding this energy consumption back to the modified load should recreate the original load provided the

consumption vector was accurate. A fraction of the error between the original load and this modeled utility load was then used in the next iteration, subtracted from the scaled CAISO data. However, later it was determined that regardless of gain, given enough iterations, the solution converges. The resulting modified CAISO load profile with pumped storage consumption removed could then be calculated for any year and used as an input into the HiGRID model. Thirty iterations of the pump removal code were run to demonstrate limit of lowest achievable error, shown in Figure 83. Notice that the load demand during the evening is lowered in accordance with the times that the pump generators are turned on (e.g., hours 25-30, 48-53, 72-78).

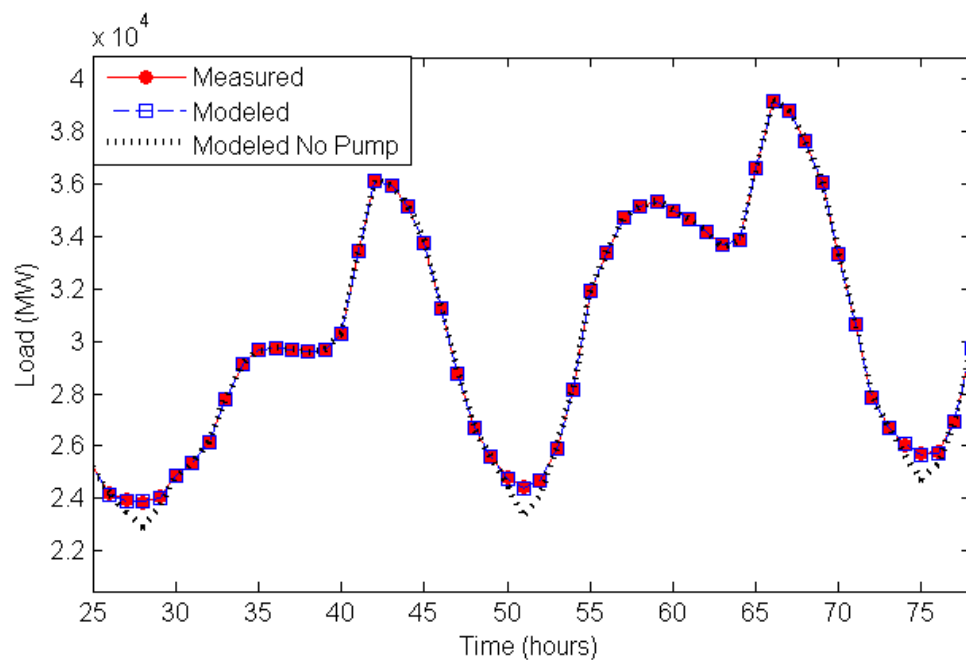


Figure 83 - Resulting Total Generation Profiles for Pump Removal Code

4.1.3.4. Electric Energy Storage Model

For this work, hourly renewable and hourly load data are used to determine the net electricity demand signal. Additionally, the scale of the analysis is across the entire state of California and the goal of this model is to explore fleet dispatch of energy storage systems and the resulting

effects on the balance signal. Based on these model constraints, there is a subset of energy storage criteria that are important for the modeling of energy storage devices. The important characteristics to incorporate into an hourly timescale model include storage capacity, available power, discharge time, depth of discharge, efficiency, and costs. An energy storage model was developed that integrates these characteristics.

The energy storage model is a physically-driven, rule-based model. It uses each system's physical behavior and operation to advise the constraints imposed. Following the logic in Figure 84, any signal can be input into the model including total demand, generation from a single renewable site, etc. Next, the maximum load value in the signal is reduced by a small increment while the nearest earlier minimum is increased and assessed an energy penalty due to inefficiencies of charging the system. The ramp rate, power capacity, energy capacity and other operational constraints are checked to ensure they are not violated for the resulting signal. If these conditions are violated then the current iteration resets to the initial values and reruns. This process continues until no more iterations can occur without violating one of the constraints.

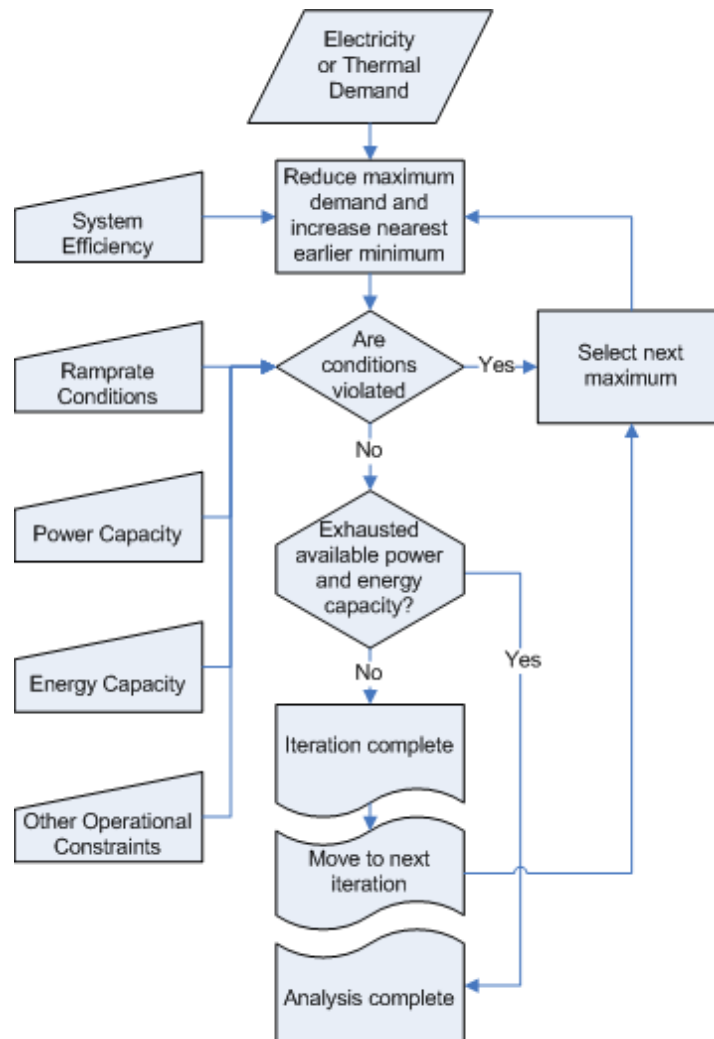


Figure 84 - Flowchart of Energy Storage Model

This control strategy shifts the maximum amount of load without violating any of the system constraints. Figure 85 depicts one example of the energy storage process that is modeled. Figure 86 and Figure 87 show the cumulative energy capacity and power demand, respectively. Notice the associated energy penalty for charging the system. This penalty is the energy that is lost in conversion or storage and does not contribute to the amount of generation.

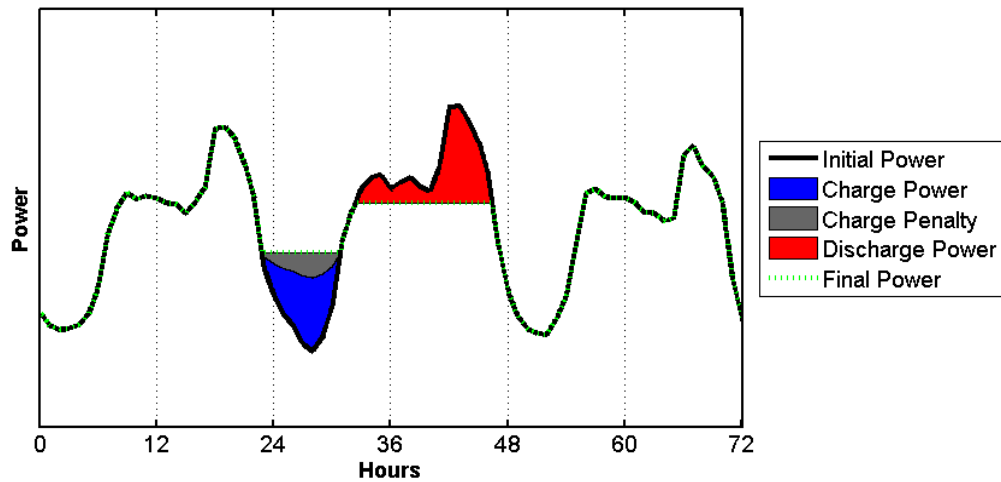


Figure 85 - Energy Storage Model Effect on Demand Signal

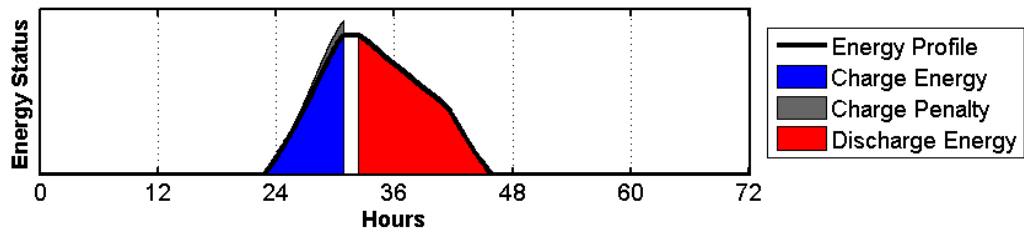


Figure 86 - Cumulative Energy Capacity of Energy Storage System

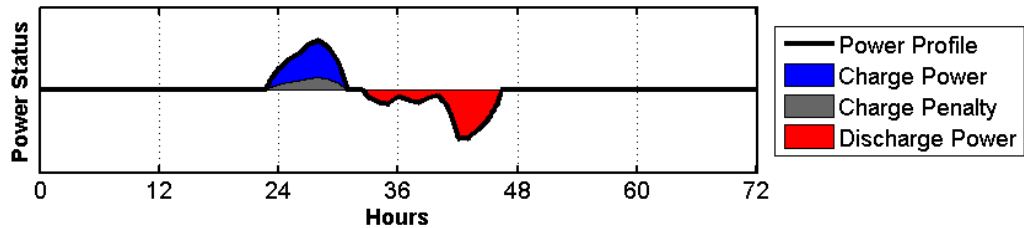


Figure 87 - Power Demand of Energy Storage System

While Figure 85 shows the resulting effect on the initial demand signal, Figure 86 provides information about the current and total energy capacity of the device. Lastly, the information used to generate Figure 87 constrains the charging and discharging power capacity as well as the ramp rate of the system, since the derivative of the power status signal is the ramp rate.

In addition to the efficiency, power capacity, energy capacity and ramp rate of the system, the model considers variable charging and discharging power and has the ability to include additional operation characteristics dependent on the technology type. While the methodology is similar for all technologies, differing values for each parameter and the inclusion of additional operating characteristics are used to distinguish between technologies.

4.1.3.5. Demand Response Model

Demand side management or demand response refers to measures that alter the profile of certain loads in response to the behavior of events on the grid, cost signals, or any other criterion.

Demand side management can be separated into two subcategories: Load Dispatch and Load Reduction. Load dispatch refers to altering the profile of a certain load type to respond to a signal. For example, smart electric vehicle chargers can decide when and how much load to impose on the grid within the time period that the vehicle is plugged in. The total energy of this load remains the same, but its profile is altered. Load reduction refers to shutting or turning down the operation of equipment loads to respond to a signal. This reduces the total energy of the load and has some profile altering capability depending on type. For example, during a large, unexpected drop in renewable generation during a particular hour, buildings can dim their interior lights or turndown their ventilation fans temporarily until the event is resolved or until occupant impact becomes unacceptable. **In this study, demand response will refer to load reductions only.** As load shifting can take various forms (cooling load dispatch, EV charging, etc...), each specific form has its own constraints and deserves its own analysis.

Two particular types of demand response are used in the HiGRID model: lighting turndown and ventilation fan turndown. The end-use profiles of these load types were determined for California

by use of the Commercial End-Use Survey (CEUS) [141]. Other end use types were also categorized, but are not a part of this particular study.

4.1.3.5.1. Lighting Turndown

Lighting turndown involves installing lighting technologies with dimmable ballasts and the necessary control equipment to reduce the power consumption. For the model, the desired power reduction is selected based on the desired occupant impact, with 15%, 30%, or 45% power reduction (designated occupant impact levels 1, 2 and 3). These three values were selected to span the achievable dimming, while maintaining sufficient lighting in the area.

The lighting energy available for DR is a combination of the “lighting” and “exterior lighting” end-use values. The total available lighting energy must be scaled by the occupant impact ($DR_{occ\ impact}$) and the effective penetration ($DR_{penetration}$) of the DR technology into the market (e.g., 50% of light fixtures in a building). Lastly, all other constraints must be applied to the signal. Important constraints to consider are weekday/weekend usage, holiday usage and time-of-day. The DR lighting model allows for the exclusion of the weekend days (as many of the DR programs do not call events on weekends due to lower electricity demand). Also the model considers time-of-day exclusions. For instance, buildings on UCI’s campus shut down in the evening and back on in the morning. When the building lighting is turned off it is incapable of providing DR and some level of lighting is required at night. The following equation is used to calculate the DR available from lighting. The resulting vector from the following equation represents the DR available from lighting for every hour of the year.

$$DR_{Lighting} = EndUse_{Lighting} \cdot DR_{occ\ impact} \cdot DR_{penetration} \cdot TimeOfDay_{constraint}$$

4.1.3.5.2. Fan Turndown

Fan turndown involves reducing the power consumption of the fans supporting HVAC in the building using control equipment. Some buildings are more amenable to turndown than others. For example, lab buildings on UCI's campus require more air changes per day than other types of buildings and as such the fan power cannot be lowered for these buildings. There are a significant number of building air conditioning systems on campus and throughout the rest of California that can operate with a reduction in fan power. For the fan turndown model the occupant impact level is selected from 1 to 3 representing turndown of the fan 10, 20 and 30% power. The reduction in fan power follows one of the affinity laws, which provides an approximation for the discharge characteristics of a fan at different fan speeds, as shown in the following equation.

$$Power_{Fan2} = Power_{Fan1} \left(\frac{Speed_{Fan2}}{Speed_{Fan1}} \right)^{2.9}$$

Just as with the other DR events, important constraints to consider are weekday/weekend usage, holiday usage and time-of-day ($TimeOfDay_{constraint}$). In addition the penetration of the given technology is considered as well ($DR_{penetration}$). The final energy available to DR from fan turndown including all constraints is calculated using the equation below:

$$DR_{Fan} = EndUse_{Controllable\ Fan} \cdot DR_{penetration} \cdot \left(1 - (1 - DR_{occ\ impact})^{2.9} \right) \cdot TimeOfDay_{constraint}$$

The resulting vector represents the DR available from fan turndown for every hour of the year.

4.1.4. Base load Generation Module

After the dispatchable load has imposed its effects, base load generation is implemented. Base load predominantly consists of nuclear, coal, geothermal generation; however other fuels like natural gas can also provide base load power. Plant operation is modeled as base load generation based on an installed capacity and capacity factor. Base load technologies have a high capacity factor, very few starts and a higher operating hour count for each year. Table 21 shows that base load plants in 2001 had an average capacity factor of 71.6% with only 7 average starts per plant per year and an average number of operating hours of 8177 out of 8760. The daily average profile for base load generation is nearly flat as shown in Figure 88.

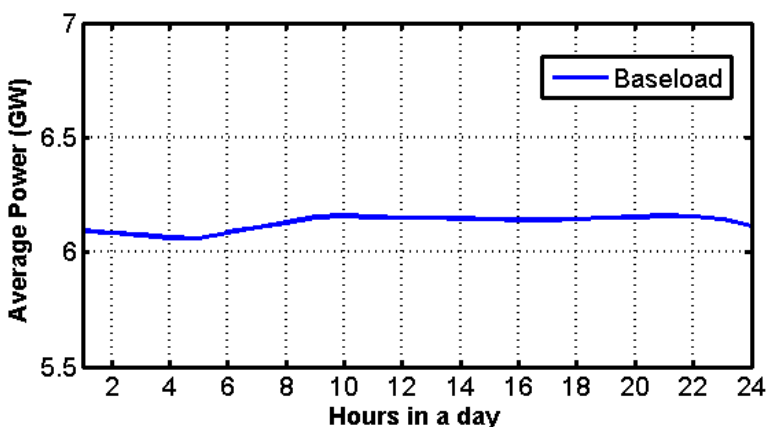


Figure 88 - Daily Average Base load Generation for FERC 2001 Data

By examining the daily average profiles for each month in 2001 (Figure 89), it becomes clear that while there is little change each hour, the generation for a given month can drop substantially. Generation is lowest during April and May, which represents the lowest demand months of the year and allows planned outages for the base load generation to ensure that they can provide the maximum power during the hotter months of June, July and August.

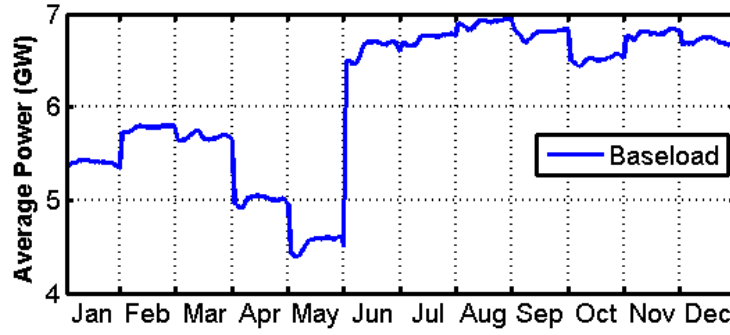


Figure 89 - Daily Average Base load Generation by Month for FERC 2001 Data

To capture this effect, the base load module uses a variable capacity factor to ensure that hours with low demand are preferentially selected for planned outages and that limited outages occur during hours with high demand. The variable step, “N”, can conceptually be any value but was selected as monthly for this model; thus, N=12. The first step is to separate the system-wide load, vector M in length, into N consecutive groups and sum them creating a vector, N in length. This approach requires as inputs, the installed capacity of the base load technology or technologies, base load fleet capacity factor and the load data to be met, in part, by base load generation. Additionally the variable step must be selected such that N is less than or equal to M.

$$E_{Load} = \sum_{i=1}^N \{Load(j) : j = M/N \cdot (i-1), \dots, M \cdot i\}$$

The first step is to calculate the relative importance of each variable load step by taking a monthly average of the load signal as shown as follows, where E_{Load} is the load to be met by base load generation.

$$B = \frac{(1 - E_{Load} / \max(E_{Load}))}{\sum_{i=1}^N (1 - E_{Load}(i) / \max(E_{Load}))}$$

The variable “B” represents the required monthly energy percentage reduction to achieve the ideal distribution of base load generation for each month. The next step is to determine the available capacity for each month and is shown as follows, where Cap_{base} is the capacity available for each of the “X” number of base load technologies.

$$C = E_{Load} / \max(E_{Load}) \cdot \sum_{i=1}^X Cap_{base}(i)$$

The next step is to calculate the capacity that should be reduced from variable “C” to achieve the desired capacity factor for the base load generation. Variable “D” presented as follows represents the total capacity across all 12 months that will be removed from “C”.

$$D = \sum C - N \cdot \sum_{i=1}^N (Cap_{base}(i) \cdot CF_{base}(i))$$

The final step is to remove a total of “D” capacity from “C” maximum capacity apportioned to provide the most generation during the months with the highest load demand (“B”). The following equation calculates the power at which the base load fleet must operate for each of the twelve months to achieve the desired yearly capacity factor and while supporting the changing load on the grid and is denoted by the variable $Cap_{setpoint}$.

$$Cap_{setpoint} = C - B \cdot D$$

Using $Cap_{setpoint}$ This method could be refined to include historical data to approximate the daily average profile while also providing the planned outage characteristics; however, the actual operation with high renewable capacity will not be the same as historical operation. Thus based

on the uncertainty with the ability of base load generation to provide dispatchable power on an hourly basis, the method as described above is used.

4.1.5. Balance Generation Module

Once renewable generation, complementary technologies, and base load generation have altered the net load demand profile, the remaining load must be met by balancing generators. Balancing generators are flexible power plants on the grid which follow the dynamics of the net load demand.

Balance generation is broken into two groups based on the duty cycles. **Load-following generation** manages larger, diurnal electricity demand swings and provides a significant amount of ancillary services. **Peaking generation or “Peakers”** provide energy for highly dynamic events including providing regulation and energy during the peak of the day when no other generator either can respond quickly enough or has the available capacity to meet the remaining load.

Understanding how the integration of renewables affects conventional generation on the grid is vital to understanding the “true” cost and value of renewable generation. The balance generation model satisfies the remainder of the load not met by the renewables, base load or other dispatchable generation.

4.1.5.1. Generator Duty Cycles

From the time-resolved FERC data [132] it is possible to calculate the general operating characteristics for each generation technology and fuel type combination, which is presented in Table 19. The average maximum and minimum plant size is shown along with plant capacity factor. Average unit count shows the average number of generators per plant as determined with the California System Operator’s summer generation assessment, which contains information

about which plants are an aggregation of multiple generators [142]. Two values for the heat rate are provided both with units of (Btu/kWh). Rated heat rate is the heat rate at rated power output, while the observed heat rate calculates the actual heat rate using the load point and a function that relates to the hourly load point to heat rate. When rated heat rate is different from observed, it is an indication that the generation type is operating away from the rated load point.

Table 19 - California Fleet Generation Operating Parameters for 2001

Generator Type	Total Capacity (MW)	Avg Max Capacity (MW)	Avg Min Capacity (MW)	Avg. Capacity Factor	Energy (GWh)	Avg. Unit Count	Rated Heat Rate	Observed Heat Rate	Avg. Yearly Operating Hours	Avg. Starts
Hydroelectric	9557	49.0	0.0	34.0%	24261	1.7	-	-	5965	104
Hydro Pumped-storage	2538	193.3	0.0	20.6%	2618	5.6	-	-	3632	166
Nuclear Driven Steam Turbine	4414	1103	162.0	85.8%	33146	1.0	10479	10478	7591	5
Coal Fueled Steam Turbine	1520	760.0	176.9	76.6%	10199	1.0	10335	10361	7614	14
Geothermal Driven Steam Turbine	1767	53.5	2.7	69.1%	10173	1.3	17581	17633	8305	7
Natural Gas Combined Cycle	1257	62.2	28.8	32.3%	3551	2.4	10026	11568	3955	58
Fuel Oil Combustion Turbine	885	61.7	26.6	14.3%	1172	1.1	14704	14625	1832	108
Jet Fuel Combustion Turbine	15	15.0	13.0	2.3%	3	1.0	16003	16375	249	31
Natural Gas Combustion Turbine	692	33.8	17.7	10.6%	515	1.4	16894	17773	1212	138
Other Generation	9002	91.7	0.0	23.0%	16511	2.2	9330	10077	4274	125
Natural Gas Steam Turbine	15022	259	40.2	40.2%	63133	1.0	10348	11507	5526	17
Thermal Generation	6860	20.5	0.1	44.8%	30476	2.2	-	-	6348	70
Total	53529	74.2	1.8	38.2%	195756	1.9	12563	13735	5689	81

Using the information in Table 19, technologies that have similar operation (i.e., duty cycles) can be grouped together. Duty cycles are determined from the capacity factor, heat rates, operating hours and starts. The most generic duty cycles are base load, dispatchable and variable. Base load operation is characterized by very high yearly operating hours, few starts and high capacity factor. Nuclear, coal and geothermal all exhibit these characteristics. Variable generation is characterized by uncontrollable and less predictable generation that is dependent largely on geological conditions and includes wind, solar, wave, tidal and small-hydro. The remaining technologies are dispatchable; however, further classification of the dispatchable duty cycle results in three additional duty cycles: hydroelectric, load-following and peaking. Hydroelectric is comprised of both conventional hydroelectric and pumped-storage. Load-following and peaking categories are more difficult than the others to separate since their operations can often exhibit similar characteristics. Peakers can be characterized as generators that turn on during times of high load to meet the power demand, but also can provide regulation and some capacity to meet reserve margin. Load-followers can typically be characterized as generation that provides the bulk of the dispatchable power and changes power output throughout the day with a relatively small portion of the generation being turned off at night. Steam turbines take more time to turn on than combustion turbines and the nature of peakers is that they can quickly come online for a short amount of time so, gas turbine plants are more likely to function as peakers and systems with steam turbines are more likely load-following units, but this is not a strict delineation with all units and therefore must be analyzed on a plant-by-plant basis.

CAISO's summer assessment document classifies most the dispatchable generators as "peakers" or a combination of "cogeneration", "thermal" or "various," which are all considered as load-followers [142]. For those that are not defined from the summer assessment document their

classification is established based on their capacity factor, yearly operating hours and starts in comparison to the plants that are defined. About 46 out of 726 plants are not listed in the summer assessment document. The duty cycle for these plants is a peaker if two criteria are met:

1. If the capacity factor for a plant is less than 12% or the operating hours are less than 40% of the year and
2. If the average duration that the generation is operating (i.e., yearly operating hours / yearly starts) is greater than 55 hours per start; otherwise the plant is a load-following plant.

Table 20 contains the resulting fleet operations separated by duty cycle and by generation type.

Table 20 - California Fleet Operating Parameters for 2001 by Duty Cycle and Technology Type

Duty Cycle	TYPE	Energy (GWh)	Max Capacity (MW)	Avg Max Capacity (MW)	Avg Min Capacity (MW)	Avg Capacity Factor	Avg Heat Rate	Avg Operating Hours	Avg Plant Starts	Plant Count
BASE	GEO	10173	1767	53.5	2.73	69.1%	17633	8305	7	36
	NUKE	33146	4414	1103.4	162.00	85.8%	10478	7591	5	4
	STC	10199	1520	760.0	176.90	76.6%	10361	7614	14	2
BASE Total		53517	7701	223.6	32.59	71.6%	12824	8177	7	42
HY	HY	24261	9557	49.0	0.00	34.0%		5965	104	251
	HYPs	2618	2538	193.3	0.00	20.6%		3632	166	39
HY Total		26879	12096	55.4	0.00	33.4%		5861	107	290
LF	CCNG	3125	903	64.2	16.67	46.6%	10786	5927	30	13
	CTFO	756	216	108.0	18.00	53.0%	12510	7094	11	2
	CTNG	150	25	25.0	14.00	68.3%	16239	6846	74	1
	OTHER	14683	7200	154.7	0.00	31.7%	10449	5332	62	66
	STNG	62846	14548	279.8	43.08	44.1%	11766	6035	15	52
	TH	28733	6140	19.7	0.00	46.6%		6520	56	481
LF Total		110293	29032	78.8	4.75	44.5%	11735	6296	49	615
PK	CCNG	426	355	60.2	41.00	18.1%	13832	1983	86	6
	CTFO	415	669	54.0	28.08	7.9%	15993	955	124	13
	CTJF	3	15	15.0	13.00	2.3%	17558	249	31	1
	CTNG	365	667	34.3	17.94	7.0%	18003	860	142	23
	OTHER	811	1208	40.2	7.49	7.6%		1096	83	59
	STNG	287	474	79.0	15.25	5.6%	13290	1118	32	6
	TH	42	66	22.1	5.00	6.1%		1397	69	3
PK Total		2350	3454	45.0	16.90	7.8%	16286	1068	100	111
INT	OTHER	1017	594	15.1	0.00	22.1%		5691	312	45
	TH	1700	653	32.5	0.00	24.8%		4625	307	42
INT Total		2717	1247	22.8	0.00	23.3%		5224	310	87
Grand Total		195756	53529	74.2	1.78	38.2%	13735	5689	81	1145

Notice that the load-following duty cycle has a combination of every kind of plant but is more heavily focused on the steam turbine, thermal, other, and combined cycle plants where as the peaker duty cycle is more focused on natural gas, jet fuel and fuel oil combustion turbines than the load-following breakdown. Table 21 compares only the total for each duty cycle.

Table 21 - California Fleet Operating Parameters for 2001 by Duty Cycle

Duty Cycle	Energy (GWh)	Max Capacity (MW)	Avg Max Capacity (MW)	Avg Min Capacity (MW)	Avg Capacity Factor	Avg Heat Rate	Avg Operating Hours	Avg Plant Starts	Plant Count
BASE	53517	7701	223.6	32.59	71.6%	12824	8177	7	42
HY	26879	12096	55.4	0.00	33.4%		5861	107	290
LF	110293	29032	78.8	4.75	44.5%	11735	6296	49	615
PK	2350	3454	45.0	16.90	7.8%	16286	1068	100	111
INT	2717	1247	22.8	0.00	23.3%		5224	310	87
Total	195756	53529	74.2	1.78	38.2%	13735	5689	81	1145

Based on the duty cycles established above and with the FERC data the resulting generation and purchased bids can be collected. Table 22 shows the energy and ancillary service market results based on the market construction in 2001. Though the construction is different from the MRTU program there are still some strong similarities. This information was extensively used for the development and verification of the HiGRID model. Reviewing this chart provides a wealth of information about the type of resources that bid into certain markets. For instance, HY provides the majority of spinning reserve and non-spinning reserve, while LF provides the majority of regulation, both down and up. For comparison, results from 2000 are included in Table 23. Creating Table 22 and Table 23 represents a significant time investment because to compile this

data the information was first inserted into an SQL database, then generation were classified by their duty cycles and then finally could be queried to develop the two tables seen below.

Table 22 - California Market Bidding Results for 2001 by Duty Cycle

Generation and Bid Quantities for 2001 (GW)	Duty Cycle						Grand Total
	PK	LF	HY	HYPs	BASE	INT	
Actual Generation	2,604	110,041	24,261	2,618	53,517	2,717	195,758
Hour-ahead Generation	1,783	109,193	24,553	2,043	52,841	2,682	193,096
Day-ahead Spinning Reserve	13	1,500	6,824	984	0.0020	-	9,321
Hour-ahead Spinning Reserve	20	1,967	6,949	1,003	0.0020	-	9,939
Day-ahead Non-Spinning Reserve	553	1,212	2,127	2,752	-	-	6,644
Hour-ahead Non-Spinning Reserve	733	1,521	2,192	2,882	-	-	7,327
Day-ahead Replacement Reserve	265	490	133	1,114	-	-	2,002
Hour-ahead Replacement Reserve	396	802	242	1,172	-	-	2,611
Hour-ahead Regulation Up	145	2,246	1,296	629	-	-	4,316
Hour-ahead Regulation Down	182	3,665	1,501	37	-	-	5,385
Supplemental Energy Incremental Bid	5,482	19,778	291	4,937	0.75	-	30,488
Supplemental Energy Decremental Bid	(26)	(17,009)	(5,786)	(1,082)	(2,732)	-	(26,634)

Table 23 - California Market Bidding Results for 2000 by Duty Cycle

Generation and Bid Quantities for 2000 (GW)	Duty Cycle						Grand Total
	PK	LF	HY	HYPs	BASE	INT	
Actual Generation	3,543	102,167	32,863	2,676	55,944	2,701	199,894
Hour-ahead Generation	3,088	92,937	31,845	3,600	55,033	2,431	188,934
Day-ahead Spinning Reserve	41	1,437	2,171	389	156	-	4,193
Hour-ahead Spinning Reserve	44	1,957	2,465	475	156	-	5,098
Day-ahead Non-Spinning Reserve	1,013	624	287	1,810	-	-	3,734
Hour-ahead Non-Spinning Reserve	1,154	1,006	451	2,055	-	-	4,667
Day-ahead Replacement Reserve	299	971	251	465	1.3	-	1,986
Hour-ahead Replacement Reserve	477	1,789	405	570	1.3	-	3,243
Hour-ahead Regulation Up	235	2,601	1,953	778	-	-	5,567
Hour-ahead Regulation Down	176	2,454	2,477	92	20	-	5,219
Supplemental Energy Incremental Bid	3,336	17,091	3,875	2,833	750	-	27,884
Supplemental Energy Decremental Bid	(197)	(9,231)	(6,759)	(447)	(3,158)	-	(19,791)

4.1.5.2. Modeling of Balancing Generator Dispatch

Load-followers provided over half of the generation, nearly half of the regulation and a large portion of spinning reserve over the years of 2000 and 2001 as was shown in Table 22 and Table 23. Peakers provide a small fraction of the energy at around 1.6% of the total generation while providing 0.4% of the spinning reserve and around 3.6% of the regulation.

Dispatch of balance generation will be affected as increases in renewables change the system requirements to maintain stable operation and reliability as is evidenced from the literature [78, 122, 143]. Understanding the effects on these generators requires that their generation is not constrained to historical operating behavior but is allowed to change operation to the extent that its operating constraints allow.

Figure 90 depicts the process by which the HiGRID tool dispatches load-following and peaking generation. In this way, peaking and load-following generator characteristics and reserve

constraints are considered. Once complete, the generator operation results in a balanced system that is able to provide the sufficient amount of power to meet the demand and reserve without violating operating constraints. The outputs from the module include time-resolved number of peaking and load-following generators and output power, as well as the heat rate, fuel use, and average startups for each type of generator.

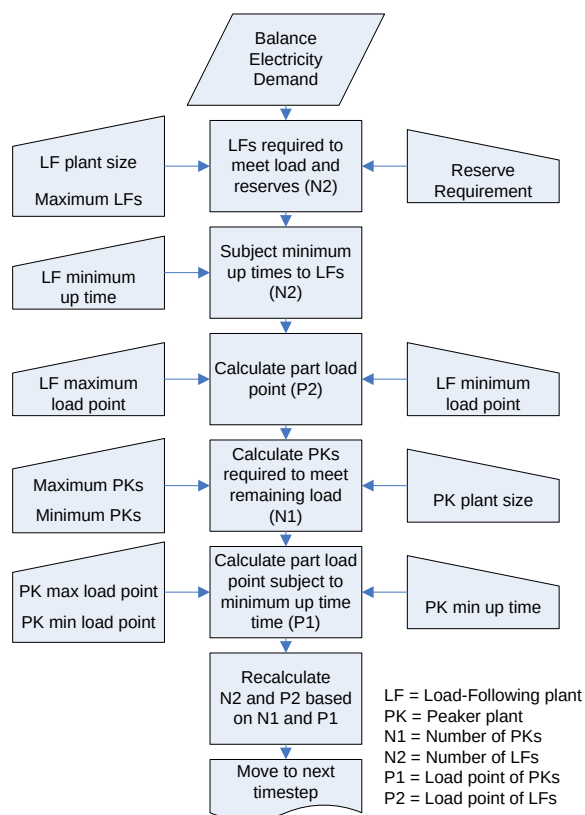


Figure 90 - Balance Generation Module Flowchart

The model assumes that there are two classes of generation (i.e., load-following and peaking) and that all plants are comprised of identical generators with operation characteristics that represent the fleet average. Characteristics that are considered in the balance generation module are listed in Table 24. The minimum and maximum load points represent the maximum and minimum achievable generation for the generator. The minimum load point for load-follower

has two values. The nominal minimum value is 75%, but the load point can dip as low as 60% in extenuating circumstances and for very short times (i.e., related to the maximum ride through time). Minimum up time represents the fewest hours that a generator must be turned on to maintain economic competitiveness and limited impact on unit lifetime. These values are gathered from generator data collected by the WECC in the Transmission Expansion Planning Policy Committee document library. Maximum ride through is applied to load-followers only and is used to mitigate situations when a generator would turn off and quickly turn on within the next few hours. The value represents the number of hours that the generator will “ride through” an event that draws its load point below 75% so that it will not have to turn off and on again in the next hour. The maximum of these two characteristics determines the minimum load prediction required to operate this model. For instance, if the minimum up time of load-following generation is the highest of all generator times and it has a value of 5 hours then the load 5 hours in advance must be either known or predicted for the model to operate. This establishes a balance between degradation, efficiency loss and ability to meet emission limits. Rated power and rated efficiency are based on the fleet average drawn from CEC power plant data [144]. The minimum and maximum unit operating values established a range for the total number of units that can operate. Notice that the maximum is set to infinity but the capability is coded into the model to consider a limit to the number of generators. The minimum number of peakers is set to two to correspond with the FERC data, which had a few peakers on for very long periods of time. Lastly, the heat rate versus load-point curves allow for variable heat rate calculations. These curves along with the rated efficiency determine the plant efficiency at part load.

Table 24 - Generator Operating Characteristics Considered for Balance Generation Module

Generator Operation Characteristics	Variable	Peaker	Load-Follower
Minimum Load Point	jL	70%	75% (60%)
Maximum Load Point	J_h	98%	98%
Minimum Up Time	UP_{min}	2 hours	8 hours
Maximum Ride Through (max down) Time	$Down_{max}$	0 hours	1 hour
Generator Rated Power	P	50 MW	70 MW
Generator Rated Heat Rate	η	11.21 MMBtu/MWh	8.75 MMBtu/MWh
Minimum Units Operating	U_{min}	2	0
Maximum Units Operating	U_{max}	∞	∞
Plant Losses	L_{plant}	3.4%	2.9%
Transmission Losses	L_{TX}	2.09%	2.09%
Transformer Losses	L_{XFMR}	0.5%	0.5%
Heat Rate vs. Load-Point Curve		Based on Solar Titan 130 Gas Turbine	Based on GE STAG 209E [38]

Three strategies can be employed for dispatching the generation based on the desired outcome:

1) maximum efficiency, 2) minimum efficiency, 3) minimum starts. The maximum efficiency strategy turns on the minimum number of generators to provide both the load and ancillary services while meeting all other generator parameters. The first step to calculating the number of generators and their load point is to calculate the minimum number of generators as follows, where the “Load” represents the remaining load, “SP” is the remaining spinning reserve and “REG” is the remaining regulation to be met by the balance generation. The naming for N2 and P2 as well as N1 and P1 come from Figure 90.

$$N2_{\min}(t) = \left\lceil \frac{Load(t) + SP(t) + REG(t)}{jL_{LF} \cdot P_{LF}} \right\rceil$$

Next, the maximum number of generators that is allowed such that the minimum up time is not violated ($N2_{\min up}$), where N is a vector the length of the load, SP and REG vectors.

$$N2_{\min up}(t) = \min \left(\{N2_{\min}(t) : t = i, \dots, i + Up_{\min}\} \right)$$

The number of load-following generators required to operate the system without violating any constraints ($N2_{\max eff}$) can be developed by comparing $N2_{\min}$ and $N2_{\min up}$ as shown in Figure 91. The minimum up time and the maximum efficiency lines bound the resulting profile such that operation in that region meets as much load as possible and provides the necessary ancillary services.

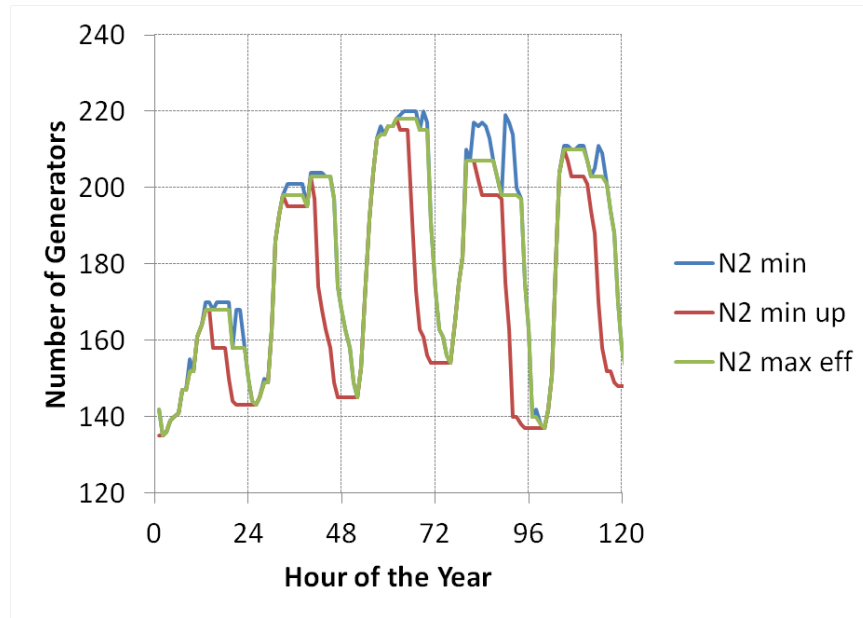


Figure 91 - Maximum Efficiency Example Calculation for Load-Followers

Calculating the resulting load point is a back calculation in the expression for $N2_{\min}$ with replacing jL_{LF} for $N2$ as follows:

$$P2(t) = \frac{Load(t) + SP(t) + REG(t)}{N2_{\max eff}(t) \cdot P_{LF}}$$

In the event that load-followers cannot meet all of the load, peakers are called to generate. Peakers are subject to generator operating constraints, just as the load-followers, so a similar process is repeated for peakers. The number of operating peaker plants and their load point is calculated using according to the following two expressions, similar to the load-followers; where the number of peakers is calculated as the highest efficiency operation using jh_{PK} in the denominator.

$$N1(t) = \left\lceil \frac{Load(t)}{jh_{PK} \cdot P_{PK}} \right\rceil$$

$$P1(t) = \frac{Load(t)}{N1(t) \cdot P_{PK}}$$

If the peaker minimum-up time is set for the same increment as the resolution of the data (i.e., 1 hour in this case) then the model is complete as the peakers can meet all of the remaining load requirements. However, if the minimum-up time is more than this amount, then it becomes a possibility for the peakers to over generate. To resolve this issue, the model is iterated. The load-following generation is run again with the peaker generation removed, and then the peakers are run again. This process can be repeated as many times as is necessary to settle on a result where all load is met with the minimal amount of peaking generation.

The second scenario is the minimum efficiency scenario. Maximum efficiency represents one extreme and minimum efficiency represents the other extreme in terms of operation envelope. While minimum efficiency is not a case that is of practical interest, it represents the maximum number of generators that can support the load and ancillary services and in so doing bounds the

solution set to achievable values. As it turns out the minimum efficiency calculation is essential to calculating the minimum starts scenario.

Minimum efficiency closely mirrors maximum efficiency except the jL is replaced with the jh and Up_{min} is replaced with $Down_{max}$. The resulting profiles for the number of generators are shown in Figure 92.

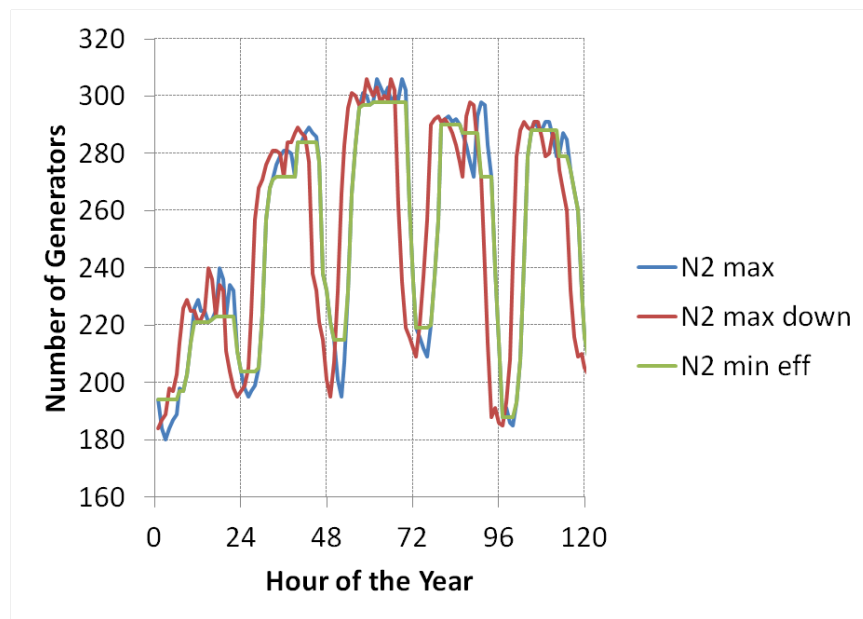


Figure 92 - Minimum Efficiency Example Calculation for Load-Followers

Maximum efficiency represents the least number of generators and minimum efficiency represents the most generators on at any given time. The minimum starts scenario represents a hybrid of both cases such that all generators stay on the longest time possible. Figure 93 shows the comparison of the minimum starts scenario in comparison to the maximum and minimum efficiency scenarios. Notice that to minimize the starts the number of generators oscillates between the minimum and maximum efficiency. As will be shown in the verification section, the minimum starts signal results in a lower error from the measured data.

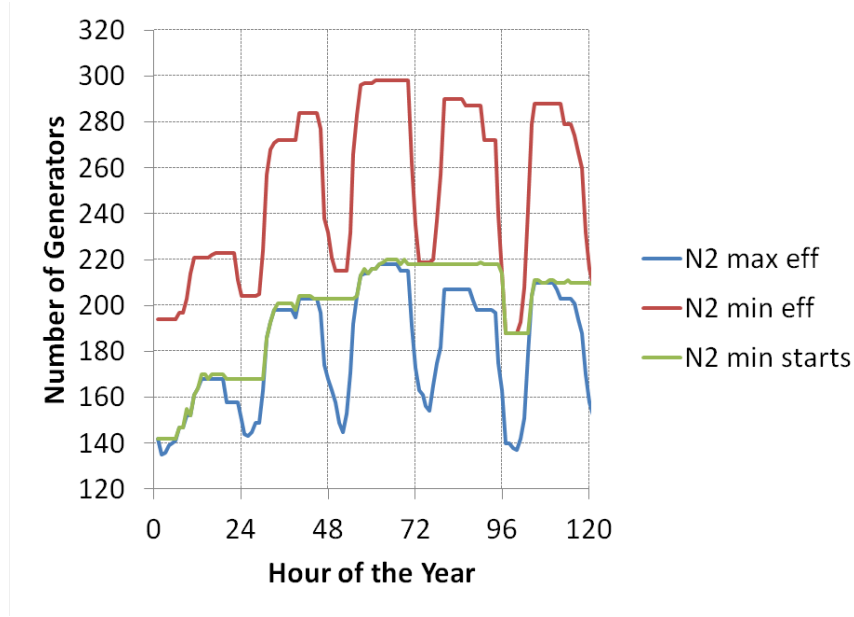


Figure 93 - Minimum Starts Example Calculation for Load-Followers

The final values for N1, P1, N2 and P2 represent the number of generators and load point required to meet the generation requirements on the system; however, to calculate the electricity delivered to load, the following expressions are used for peakers and load-followers, respectively.

$$E1_{\text{Delivered to load}}(t) = N1(t) \cdot P1(t) \cdot P_{PK} \cdot (100 - L_{plant}) \cdot (100 - L_{TX}) \cdot (100 - L_{XFMR})$$

$$E2_{\text{Delivered to load}}(t) = N2(t) \cdot P2(t) \cdot P_{LF} \cdot (100 - L_{plant}) \cdot (100 - L_{TX}) \cdot (100 - L_{XFMR})$$

Now that the number of generators and the load point of each generator are calculated, the time-resolved heat rate can be calculated. Part load performance data for a GE STAG 209E combined cycle generator is used to model load-following heat rate as shown in Figure 94 [38]. The curve exhibits two unique regions that define the operation of the plant. For high plant output (i.e., 100-80%) the heat rate increases slowly. Below 80% plant output the heat rate rises rapidly equivalent to rapid reduction in the efficiency.



Figure 94 - Part-Load Performance of a GE STAG 209E Combined Cycle Generator [38] (two turbines)

A similar process is used for representing the heat rate of the peaking fleet. UC Irvine's 13.5 MW Solar Titan 130, gas turbine generator is normalized and then used to model the peaker operation as shown in Figure 95. There is a similar linear region from 100% to 90% part load then a rapid increase for 90 and below.

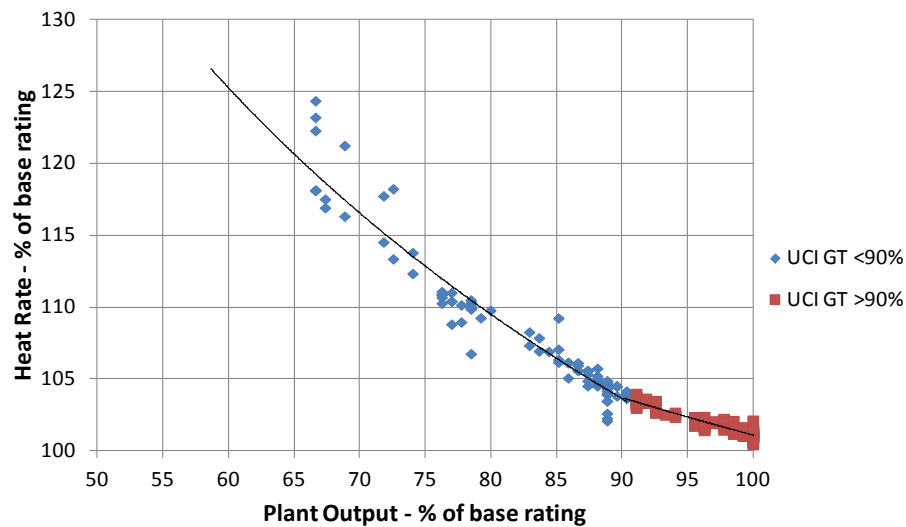


Figure 95 - Part-Load Performance of a Titan 130 Simple Cycle Gas Turbine Generator

Figure 94 and Figure 95 represent the performance as a function of the base rating and the base power ratings used for this equipment is shown in Table 24. In particular, the nominal plant size for the entire fleet, based on FERC data, is 50MW for peakers and 70MW for load-followers. A piece-wise function was used to model the heat rate relationship with load point. The high load point region uses a linear curve fit, while the low load point region uses an exponential curve fit. To calculate the fuel consumed during each time step the following expression is used, where HR_{LF} is the heat rate based on the load point, P2. A similar expression can be used to calculate the fuel use for peakers.

$$Fuel_{LF}(t) = N2(t) \cdot P2(t) \cdot P_{LF} \cdot HR_{LF}(t)$$

Converting a heat rate to fuel to electric efficiency can be done using the following expression, where 3.413 is a constant conversion factor from MMBtu and MWh. A similar expression is used to calculate the fuel to electric efficiency for peakers.

$$\eta_{LF}(t) = \frac{3.413}{HR_{LF}(t)}$$

The following assumptions were made in the development of the model.

- **Balance generation is represented by two types of generators (i.e., peakers and load-followers).** These generators are representative of a fleet of generators operating with a similar duty cycle.
- **All peakers have the same operating parameters** (i.e., peak power, heat rate) and all peakers operating during a given time step behave in the same manner (e.g., power output), based on the fleet average.

- **All load-followers have the same operating parameters and all load-followers operating during a given time step are dispatchable and behave in the same manner.** This means that typical operational parameters for load-following and peaking generation are used to represent the entire fleet of each generating type, independent of the size of that fleet. This simplification from actual operations, where each plant's operation is unique, is based on the use of historical data to verify the general operating assumptions.
- **Transmission constraints are not modeled.** For small-scale systems this assumption means that transmission/congestion issues do not cause a change in operation. That is to say, no transmission congestion occurs for small-scale systems and sufficient power can be provided to meet the demand. Large-scale systems are handled differently. The first three assumptions remove the need for considering spatial resolution and dispatch order for each specific generator but also remove the ability to directly calculate any congestion constraints. This is addressed by integrating results from previous studies and historical data and by including an additional inefficiency resulting from violations of transmission system constraints. Previous studies include WWSIS by NREL and a report by CAISO that details the effects of renewables at 20% renewable penetration within California [78, 122].
- **Historical spinning and non-spinning reserve margins are known and maintained in the model.** Base load generation is independent of the need for load prediction, hydroelectricity operates to meet seasonal constraints with daily dispatchability, and peaker and load-follower operations need an accurate prediction of the load to satisfy their respective operational constraints.

- **Frequency regulation margins are dependent on the base renewable penetration level.** Higher base renewable penetration levels achieved due to the integration of variable wind and solar power resources increase the short-timescale uncertainty in the net load demand, increasing the magnitude of these margins. The extent to which these margins increase are extrapolated by trends displayed in a CAISO report [78], detailing effects of variable renewable resources on grid operations.

4.1.6. Emissions Module

The balance generation module provides information about the operation of the balancing generator fleet with respect to start-up condition (hot, warm, cold), part-load condition, and number of generators online at every point in time. From these parameters, the fuel use and therefore greenhouse gas and criteria pollutant emissions of the balance generator fleet can be calculated.

The emissions from the balance generator fleet can be divided up into two categories:

- Operating Emissions
 - Bulk Generation
 - Start-up Emissions
- Upstream Emissions
 - Fuel Extraction
 - Fuel Processing / Cleanup
 - Fuel Delivery

4.1.6.1. In-Operation Emissions

Operating emissions refers to all of the greenhouse gases and criteria pollutant emissions that are produced during the operation of balancing generators. This category can also be further

divided into two categories: emissions produced due to providing bulk generation and emissions produced during start-up events. Bulk generation emissions involve the oxidation of coal or natural gas fuel streams to provide bulk electric energy for the grid. This accounts for the changes in efficiency due to varying part-load operation of different generator types. Start-up event emissions refer to those that are produced due to the extra amount of fuel oxidized to bring a particular generator online. During this process, auxiliary loads in the power plant must be met, and combustion conditions have not reached their design point. These factors contribute to increased GHG and criteria pollutant emissions.

In this model, the emissions factors used for operating emissions are as follows:

Table 25 - HiGRID GHG Emissions Factors

<u>Fuel Stream</u>	<u>Greenhouse Gas Type</u>	<u>Emissions Factors</u> <u>(Metric tons / MMBTU fuel)</u>	<u>Global Warming Potential</u>
Natural Gas	CO ₂	5.307 E -2	1
	CH ₄	1.055 E -6	25
	N ₂ O	1.055 E -6	300
Coal	CO ₂	1.031 E -1	1
	CH ₄	2.260 E -6	25
	N ₂ O	2.010 E -6	300

The emissions factors for CO₂ have been obtained from a literature review of documented emissions factors [145, 146]. For natural gas, the emissions factors for CH₄ and N₂O were obtained by calculating the in-operation emissions and fuel use from data for natural gas-fired power plants provided by the eGRID database [72]. For coal, however, the CH₄ and N₂O emissions factors were used as tuning parameters. This was deemed appropriate since the vast

majority of coal power supplied to the state of California originates in power plants that are outside of the state, where emissions regulations and performance vary much more widely than in-state power plants. This variation was confirmed by emissions and fuel use data for coal fired power plants from eGRID.

The startup fuel emissions are based on the number of starts a generator performs during a given time period, the installed capacity of that generator and a startup fuel factor. Based on the CEC Cost of Generation model inputs, a value of 2.8 MMBtu/MW/start is used to assess the fuel consumption due to start-ups [147].

Using these emissions factors, the total GHG emissions in CO₂-equivalent units was compared with that presented by the California Air Resources Board (CARB) Greenhouse Gas Inventory [148]. The case for comparison is the reference case of the year 2005. The capacity of each type of technology (renewable and non-renewable) was sized to match the energy provision presented by the CEC for the corresponding year [149]. Design point efficiencies for load-following power plants was determined by using the operating efficiencies specified by the CEC for power plants in the appropriate year [144] and assuming a 92.5% average part-load condition. This assumption takes into account load variations and margins for spinning reserve and regulation capacity. The comparison of the HiGRID model to the CARB greenhouse gas inventory for the year 2005 is as follows:

Table 26 - Verification of HiGRID GHG Operating Emissions

<u>HiGRID Model</u> <u>(Mtonnes CO₂e)</u>	<u>CARB GHG Inventory</u> <u>(Mtonnes CO₂e)</u>	<u>Error [%]</u>
106.67	108.89	-2.04

The HiGRID model agrees quite well with the GHG emissions recorded by the CARB GHG inventory. The slight difference lies in the determination of design point efficiencies; however this difference is small relative to the sensitivities of scenario-based factors that the model is applied to.

It is also important to note that the use of biofuel (biogas and biomass) is regarded as having zero net operating emissions under the assumption of using carbon neutral biofuel types. The use of biofuel does contribute to upstream emissions, however.

4.1.6.2. Upstream Emissions

Upstream emissions refer to all of the greenhouse gases and criteria pollutant emissions that are produced due to the extraction, processing, and delivery of relevant fuel streams. All of these processes require energy in different forms, which are typically supplied by primary sources that produce greenhouse gas and criteria pollutant emissions.

The upstream emissions regarding the extraction of coal and natural gas fuel streams were obtained using the GREET model produced by Argonne National Laboratory [76]. The GREET model determines the greenhouse gas emissions regarding all of the energy used to extract the relevant fuel streams (i.e. natural gas fracking, coal mining, etc...) and process the pure products into commercially usable fuels. In addition, the GREET model also takes into account the greenhouse gas contribution that results from fugitive emissions of CO₂, CH₄, and N₂O due to inefficiencies in the extraction/mining process and leakage from pipelines. For both coal and natural gas, the presence of fugitive emissions represents a non-trivial contribution to the CO₂-equivalent greenhouse gas emissions. Using GREET, the following emissions factors are determined:

Table 27 - HiGRID Upstream Emissions Factors

<u>Fuel Stream</u>	<u>Emissions Factor (g CO₂e/MMBTU input)</u>
Natural Gas	4869
Natural Gas w/ Fugitive Emissions	9305
Coal	1252
Coal w/ Fugitive Emissions	4267

It is important to note, however, that the upstream emissions contribution due to the use of grid electricity has been subtracted out from these factors. This is necessary since all grid emissions are taken into account with the operating emissions of the electric grid.

4.1.7. Handling of Excess Generation (Curtailment)

Generation that exceeds causes the net load demand to drop below minimum levels must be transmitted to another entity that can use the electricity (i.e., exported), or curtailed if it cannot be stored. A minimum level of generation is present on the grid due to base load plants being unable to vary their power output in response to dynamic renewable generation, balancing power plants being unable to drop below their minimum part-load level, and the need for some conventional power plants to be online for reliability considerations. In the early stages of renewable adoption export of unwanted system generation dynamics could be absorbed by the larger grid; however, as more and more communities begin to integrate renewables to meet state RPS requirements, it will no longer be possible to export those dynamic generation changes to the external grid. Additionally, based on the current market structure in California, renewables are must-take (i.e., every MWh must be purchased, independent of the time of generation); however, as renewables increase, this research shows that there is a point at which the grid can

no longer support a must-take approach. Thus the more renewable capacity that is integrated into the grid the greater the potential need for curtailment.

For each renewable mixture, the other modules calculate the necessary curtailment considering system reliability requirements. The challenge is to appropriately distribute that curtailment between the resources that generate them. This challenge is complicated by the fact that different technologies are better able to curtail than others. For instance wind turbines must engage their brakes to stop the blades from spinning. Depending on the braking mechanism, additional use can degrade the equipment faster. Solar PV power will retain the voltage potential whether or not current is drawn so curtailment on solar PV is relatively easier. While solar photovoltaic technologies would have an easier time curtailing generation, it is not reasonable that the burden of curtailment based on wind turbine generation be placed on the PV plants. For this model it is assumed that each technology shoulders curtailment throughout the year based on the proportion of total renewable energy that it contributes. There are exceptions if a selected power line was overloaded and curtailment of a particular resource is essential from a grid stability point-of-view. Energy apportioned curtailment calculations must be calculated at the resolution of each time step and keeps track of the energy generated for the year. In this way the curtailment is fairly distributed between renewable resources.

4.1.8. Cost-of-Generation Module

The purpose of the HiGRID Cost of Generation module is to calculate the levelized cost of electricity (“LCOE”) for any given portfolio of generating capacity. The LCOE represents the discounted revenue per MWh that would be required to recover all of the costs incurred over the life of the generating technology to produce all of the MWh. In this regard, the term costs includes capital costs, operations and maintenance costs, fuel costs, financing costs, and all taxes.

The levelized cost of electricity yields a single value for each generating technology that takes into account the costs, operating parameters, and the economic life of that generating technology. The primary purpose of the levelized cost of electricity calculation is to allow a comparison of different generating technologies on a cost per MWh basis despite different costs, operating parameters, and economic lifetimes.

The HiGRID Cost of Generation module calculates the portfolio LCOE for any given portfolio of generating technologies as the MWh-weighted average of the technology-specific LCOE for each generating technology in the portfolio. The portfolio of generating technologies is determined by the interaction of the Base Load and Balancing Generation Modules with the Renewable Generation Module and Dispatchable Generation Module. Calculation of the portfolio LCOE enables a dynamic comparison of different generating portfolios that, in turn, allows for least cost portfolio optimization within specified technical and operating constraints.

The cost of generation module is, in part, based on the CEC's model for determining the LCOE of generation technologies [147]. The cost of generation module draws on performance information for each technology including installed capacity, electricity generated, fuel consumed, starts and hours of operation to calculate the LCOE from each generator type and the portfolio as a whole. Some of the impacts of variable renewables are not evident from the direct cost of installing renewables, but rather, manifest themselves in an increased need for conventional generation capacity that causes a rise in the cost of those technologies needed to support the variability of renewable generation. Figure 96 depicts the flow chart for the cost of generation model.

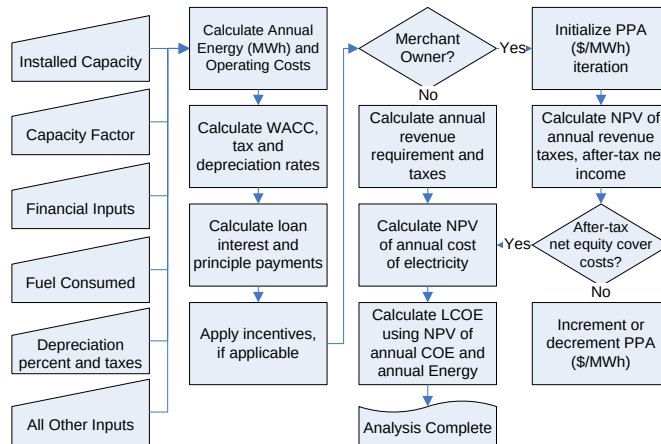


Figure 96 - Cost of Generation Model Flowchart

Model inputs are shown in the left of Figure 96 and include:

- Gross capacity
- Capacity factor
- Instant cost
- Fixed O&M cost
- Variable O&M cost
- Heat rate
- Heat rate degradation
- Capacity degradation
- Debt term
- Economic life
- Tax life
- Ad valorem tax rate
- Tax incentives
- Buy-downs

- Feed-in tariffs
- Annual starts
- Start-up fuel
- Plant losses
- Transmission losses
- Transformer losses
- Transmission cost
- CO₂ emission factors

The LCOE for private (merchant) ownership is calculated using an income cash flow methodology whereas the LCOE for investor- and publically-owned utilities is calculated using a revenue requirement methodology. The two methodologies differ in many respects, including in their treatment of taxes, depreciation, and required rates of return. Each generating technology may have only one type of owner per run in the current HiGRID Cost of Generation module, and all results to-date are based on merchant (private) ownership of generation, assuming 60% equity and 40% debt.

The HiGRID Cost of Generation module currently includes cost and initial operating parameters for 47 different generating technologies, both fossil-fueled and renewable. Costs include, among others, capital costs, fixed and annual operations and maintenance (“O&M”) costs, fuel costs, tax rates, and financing costs. Initial operating parameters for each generating technology include the nameplate capacity, annual load factor, initial heat rate, annual heat rate degradation, and annual capacity degradation. The annual number of starts and required start-up fuel are included, where applicable.

Most of the costs for new capacity included in the HiGRID Cost of Generation module are derived from the generation plant costs developed in the CEC Cost of Generation model. In addition, the HiGRID Cost of Generation module includes so-called “legacy” generating technologies. Legacy generating technologies are included to reflect already existing electricity generating capacity that may be largely or fully depreciated. Such legacy generating technologies include all generating capacity currently serving California. The installed capacity for each legacy generating technology included in the integrated HiGRID model is based on the estimated capacity mix serving the electric load for California in 2005, determined, in part, by a review of the CEC’s Database of California Power Plants [80].

The initial legacy generating technologies included in the HiGRID Cost of Generation module are nuclear capacity, large hydro capacity, coal-fired capacity, natural gas-fired base load capacity, natural gas-fired intermediate load capacity, and natural gas-fired peaking capacity. The parameters for each legacy generating technology are considered to be representative of the aggregate capacity included within that technology and are included to allow for a full representation of the generating capacity serving California. The purpose of including a full representation of all generating capacity is to allow for future analysis that might include dispatching of even legacy base load generation as the level of renewables penetration increases to very high levels. Fuel price forecasts are based on mid-range values in the CEC Cost of Generation model and may readily be changed to reflect changing long-term market conditions.

Because of their assumed age, all capital costs associated with the legacy generating technologies are assumed to be fully depreciated, i.e., there are no capital costs included in the LCOE. The LCOE for each legacy generating technology is based solely on its fuel costs and on its specified fixed and variable O&M costs. Each legacy generating technology has a specified aggregate

heat rate and capacity factor, as well as heat rate and capacity degradation factors representative of that technology.

System balancing will become increasingly difficult as the penetration level of variable renewable generating technologies increases. Changes in annual load factors of natural gas-fired generating technologies may change as a result of changes in, for instance, the renewable penetration level and the associated natural gas-fired generation required for system balancing. All of the initial operating parameters of the HiGRID Cost of Generation module are dynamic and subject to change based on the output from the Renewable Generation Module and Dispatchable Generation Module. This is an important feature that enables the integrated HiGRID model to find the most economical means of system balancing through the iterative calculation of the LCOE of different generating technology portfolios.

Annual capacity factors are an important factor in determining the LCOE for any given generating technology. The impact on the LCOE of changing the annual capacity is clearly illustrated in Figure 97, which shows the LCOE (excluding all incentives) over the full theoretical range of capacity factors for four of the generating technologies: advanced natural gas combustion turbine (“Adv CT”), advanced natural gas combined cycle (“Adv NGCC”), onshore wind, and 1-axis tracking photovoltaics (“1-Axis PV”). As the annual capacity factor increases, more and more MWh are generated. Since everything else is held constant, increasing the capacity factor leads to a continually declining LCOE.

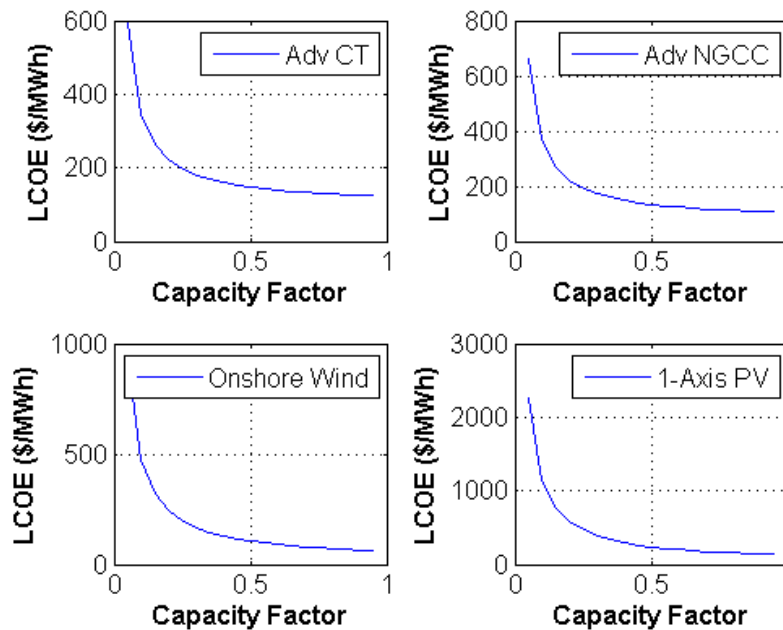


Figure 97 - Impact of Annual Capacity Factor on LCOE (Excluding all Incentives)

The importance of the LCOE for any given generating technology is that it, in turn, impacts the portfolio LCOE. The LCOE of different generating portfolios are compared and any changes in a portfolio's LCOE have important implications for determining the optimal portfolio to meet California's load. At lower capacity factors, capital costs become more dominant relative to fuel costs. In addition, lower capacity factors generally result in higher heat rates and increased emissions of all types. These effects have important implications for the true costs of system balancing as renewable penetration levels increase.

The economic life of a generating technology also impacts its LCOE, as illustrated in Figure 98. Figure 98 illustrates the LCOE for the same four generating technologies as above, this time changing the theoretical economic life over a range of 5 to 40 years. As the economic life of a technology is extended, there comes a time where the (negative impact) reduction in MWh generated due to cumulative capacity and heat rate (where applicable) degradation factors

outweighs the positive impact of the extended economic life. Fuel costs become more dominant relative to capital costs. This effect is particularly dramatic for the 800 MW advanced NGCC generating technology due to the combined effect of an ever-increasing heat rate in the face of rising natural gas prices. The two renewable generating technologies show very little increase in the LCOE as their MWh generated in the later years wane because these technologies are immune from the impact of fossil fuel prices. The interaction of financing costs, taxes, and depreciation also contribute to the shape of the curves in Figure 98. Thus, the end of the twelve-year financing term for the advanced NGCC generating technology contributes to the upward turn of the LCOE as that technology's economic life is extended.

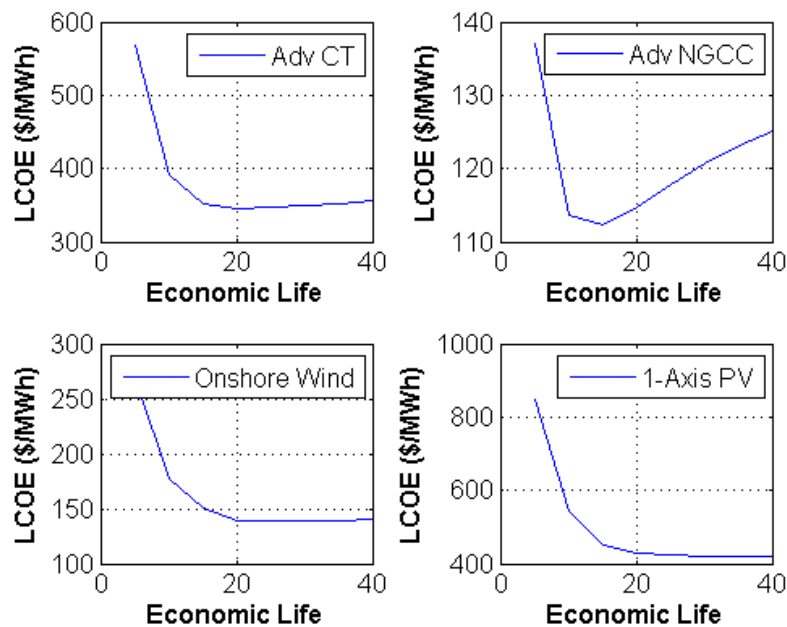


Figure 98 - Impact of Economic Life on LCOE (Excluding all Incentives)

The issue of the appropriate level of transmission costs to allocate to new renewable generation is one that is widely debated in California and elsewhere. The integrated HiGRID model relies on the in-state per MWh transmission costs developed by the Renewable Energy Transmission Initiative for all renewable generating technologies [150]. The capacity of each block of

renewable generation installed by the HiGRID Renewable Generation Module is assigned to a California Renewable Energy Zone (“CREZ”) based on the geographic location of the installed capacity. For each renewable generating technology included in the generating portfolio, a MWh-weighted average transmission cost is calculated, based on the location and generating profile of each block of installed capacity included in that generating technology category.

Transmission costs associated with fossil-fueled generation are based on CAISO wheeling charges and other transmission-related costs from the CEC Cost of Generation model. Rooftop solar PV (in 10 kW increments) have been included as a separate (distributed) generating technology with no transmission costs or associated losses.

Tax incentives and California Solar Initiative incentives may either be included in or excluded from the LCOE calculations in the HiGRID Cost of Generation module to allow for sensitivity analysis. Comparative results with and without such incentives will be provided at a later date.

The HiGRID Cost of Generation module is designed to allow all inputs to be changed as market conditions and other assumptions change. New generating technologies may be added to the model and the costs and initial operating parameters for generating technologies already included in the HiGRID Cost of Generation module may be changed with ease.

The HiGRID Cost of Generation module works in tandem with the other modules of the integrated HiGRID model, receiving revised portfolio definitions with associated capacities and operating parameters from both the Renewable Generation Module and the Dispatchable Generation and providing back to those modules a revised portfolio LCOE that measures the cost impact of changing the renewable energy capacity component of the generating mix serving California. The integrated nature of the HiGRID cost and generating modules and the relative

ease with which the input parameters may be changed result in a powerful yet flexible analytical tool that will provide significant insights into the technical and cost impacts associated with the increased penetration of renewables.

4.1.9. California Model Verification Summary

This work is not intended to advise utilities on the specific locations of power plants required in the future or on the capacity of transmission lines required to alleviate congestion constraints with additional renewables; rather, this study addresses the technical feasibility of installing novel electric sector options and indicates the resultant changes to costs and operation of the grid for any mixture of renewable technologies and the effect of including complementary technologies. The result of constructing the tool in the way described and subjecting it the aforementioned assumptions is a tool that can quickly span a variety of scenarios and can perform optimizations if desired to more accurately understand the cost and performance implications for installing novel options.

The California HiGRID model was verified using hourly resolved generation profiles for each generator within the state of California from the FERC data [132]. Table 28 presents a comparison of the percentage differences between modeled values and historical FERC data for each specific resource type. Errors in base load and hydro models, cascades to the load-following and peaking models because the total load demand and spinning reserve must be met regardless of any errors in previous models.

Table 28 - Percentage Difference Between Modeled Generation and FERC Data

Model Year	Hydro	Base load	Load-Following	Total
2000	17.2%	12.0%	7.5%	11.9%
2001	13.9%	10.7%	5.6%	8.9%

While the percentage difference shows a measure of the total error it is also important to understand when the error occurs. Instantaneous generation profiles display when the error occurs, as shown in Figure 99.

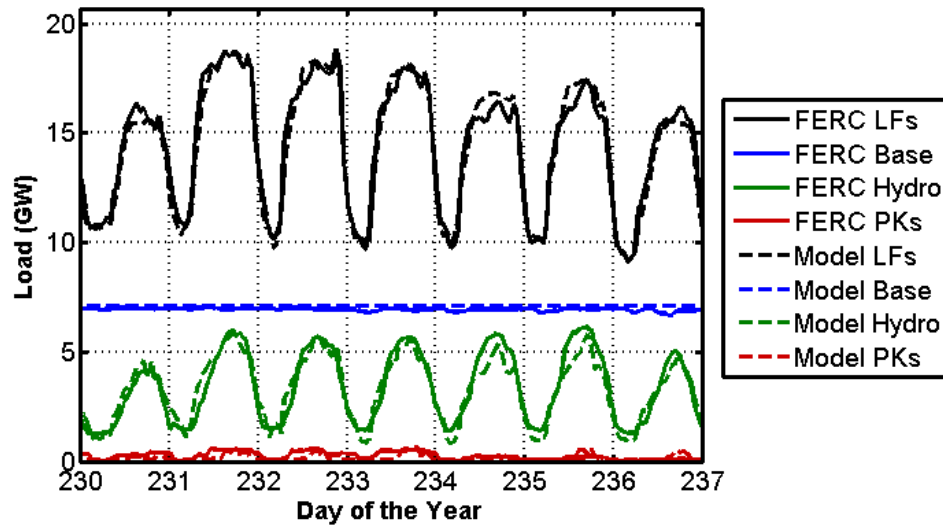


Figure 99 - Hourly In-State Generation Comparison to FERC Data for 2001

Additionally, daily average curves and load duration curves are included in Figure 100 and Figure 101, which present the distribution of generation throughout the year. The daily average represents the agreement to diurnal behavior by averaging each hour of every day together. The load duration curve is useful to ensure that the actual system and the modeled system have similar range and load distribution for the year.

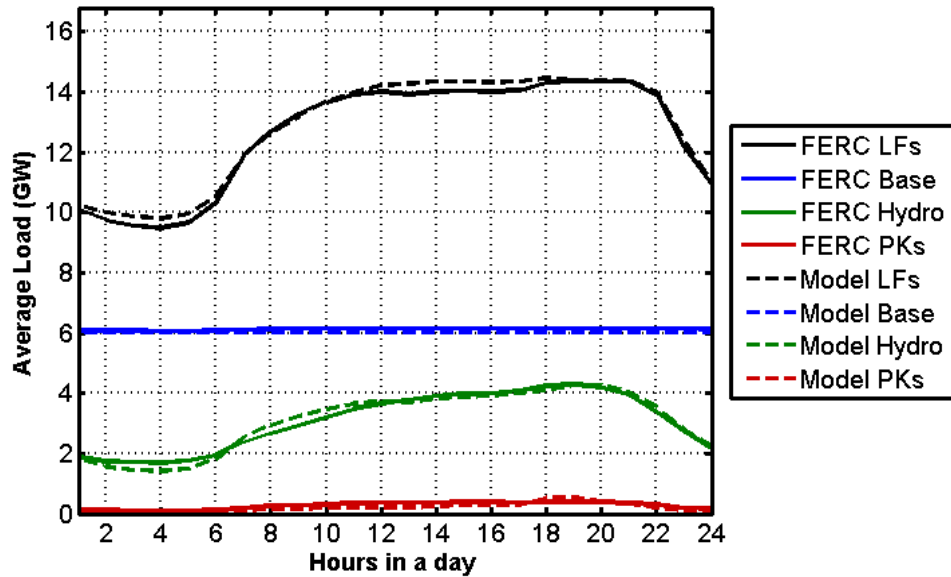


Figure 100 - Daily average Comparison to FERC Data for 2001

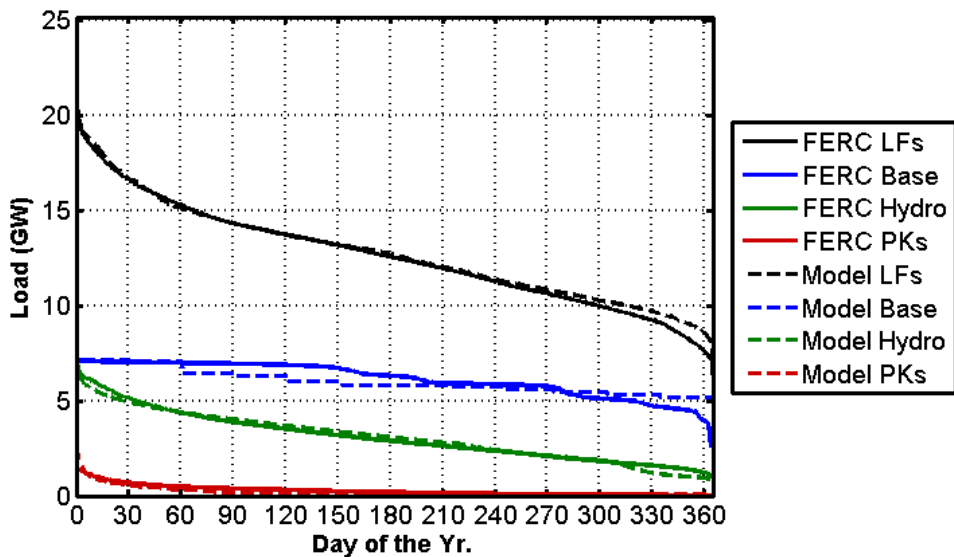


Figure 101 - Load Duration Curve Comparison to FERC Data for 2001

Agreement of the hydroelectric, base load, and load-following modules with the FERC data is good; however, the error resulting from the peaker model appears high. Operation of peakers is necessary to assure grid stability during high load times and highly dynamic periods, but can be unpredictable. The amount of peaking is determined by the available capacity of the system and the operational characteristics of the generators. Peakers can turn on for a few hours each day,

which is not feasible for large base load or load-following plants that can take hours to start up. The utilization can change dramatically from one day to the next and they are often bid into the non-spinning reserve market because these units have the capability to turn on very quickly. It is for these reasons that determining when peakers are turned on is challenging and the error for this module is high. While, the error for the peaker model is high, the contribution of peaking to the total energy is low at around 2% of all the supplied energy. Thus the three contributing factors to error of the peaker generation signal are 1) the dynamic requirements of peaker generation; 2) peaker's non-correspondence with the generation signals from other generation types and 3) compounding error for each successive resource model (i.e., hydro, base load, load-follower and finally peaker).

4.2. Light-Duty Transportation Sector

A modeling platform has been created to capture the environmental and economic performance of the light-duty transportation sector, while taking into account its operational interactions with the electricity and water supply sector. This consists of two primary alternative vehicle types: plug-in electric vehicles (PEVs) and fuel cell vehicles (FCVs). The component models attempt to capture all of the characteristics of utilizing each vehicle type that are relevant for electric grid and water reservoir interactions, and are described as follows.

4.2.1. Plug-in Electric Vehicle Charging Infrastructure Modeling

In order to capture the synergies and interferences between the use of electric vehicles and options in other resource sectors from the perspective of environmental performance and cost, a model of the effects of plug-in vehicle charging has been developed. This includes both Plug-in Hybrid Electric Vehicles (PHEVs) and Battery Electric Vehicles (BEVs)

The UCI-STREET model includes a module which is able to calculate the time-resolved profile of the electric vehicle charging load based on infrastructure configuration and vehicle properties.

The aspects of this model that are relevant to the proposed analysis are described here.

4.2.1.1. Vehicle Travel Data

The vehicle travel behavior data used in this model are derived from the 2009 National Household Travel Survey (NHTS) [62]. Several processing steps were required in order to prepare the data for input to the model. In particular, data for California were selected, trips occurring without a personally owned vehicle were deleted, person-chain data were converted to vehicle-chain data, daily trips data with unlinked destinations or significant over-speed were deleted, and tours were organized into home based daily tours (first trip from home, last trip to home). 20,295 vehicles were selected covering 83,005 single trips with an average of 7.85 miles per trip and 32.13 miles per vehicle per day.

4.2.1.2. Vehicle and Infrastructure Configuration Parameters

The plug-in electric vehicle infrastructure model allows for consideration of a number of different configurations for the charging infrastructure and vehicle capabilities. These different configurations alter the charging profile and the effect that vehicle charging has on the electric grid as travel patterns are adjusted to meet consumer needs. The primary input configuration parameters for electric vehicle service equipment (EVSE) are as follows:

- **Infrastructure Options:**
 - **Charging Location:** The locations with electric vehicle chargers installed.
 - Home: EVSE only available at residences
 - Work: EVSE only available at workplaces

- Home and Work: EVSE available at residences and workplaces
- Everywhere: EVSE available at residences, workplaces, and all commercial locations (i.e. shopping malls, etc...)
- o **Charging Power per Vehicle**: The maximum charging power of installed electric vehicle chargers per unit.
- **Vehicle Parameters**:
 - o **Electric Range**: The maximum electric range of a PEV vehicle in miles. For BEVs, this is the entire vehicle range, for other types, it is the range after which supplementary propulsion would need to be activated.
 - o **Vehicle Efficiency**: The “fuel economy” of a PEV in kWh per mile.

Once these parameters have been specified, the penetration of plug-in electric vehicles is input to represent the fraction of the total statewide vehicle-miles-traveled that is met by electric vehicles, scaling the charging profile of the vehicle fleet. The annual vehicle miles traveled for the state was obtained from the EMFAC model utilized by the California Air Resources Board [151].

4.2.1.3. Vehicle Charging Profile Dispatch for PHEVs

Electric vehicle energy usage is modeled using a tool that accounts for the electricity and fuel use associated with plug-in hybrid electric vehicles (PHEV) constructed by Li Zhang [61, 152]. The two part model determines how vehicles are operating and charging. Inputs include: vehicle type, miles per gallon, energy consumption per mile, battery depth of discharge, vehicle range, charging power, charging location and charging strategy. The model interfaces with National

Household Travel Survey (NHTS) data to provide realistic trip information. Using the inputs and trip data, electric and fuel consumption profiles can be determined.

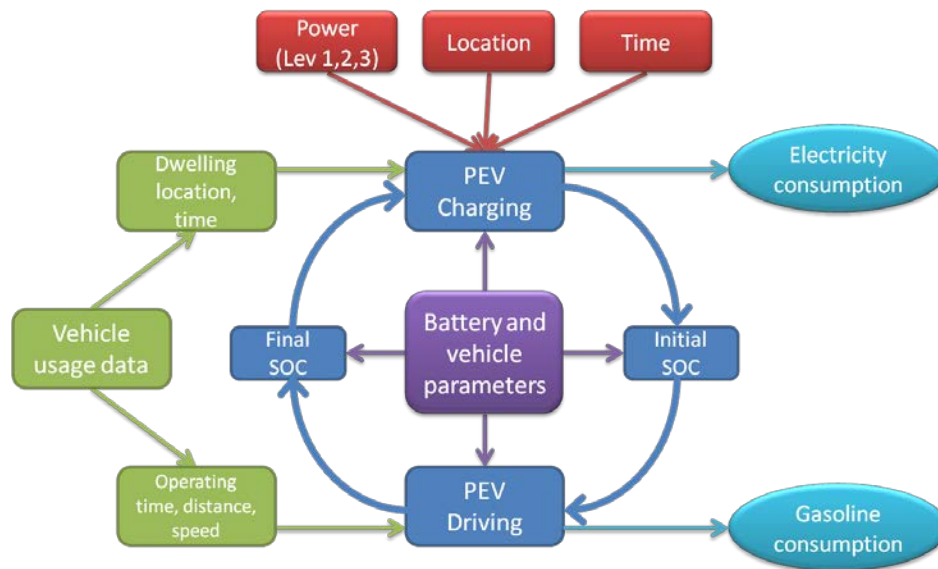


Figure 102 - PHEV Operating and Charging Model

Driving distances or durations may require that the vehicles operate using the gasoline engine. The model ensures that all trips can be made either on electricity or gasoline with a goal to maximize the portion of miles driven using electricity.

The model can consider two different charging locations and their combination, which includes home-only and both home and work. This assumes that the opportunity exists for a vehicle owner to charge the vehicle at either home or home and work, respectively.

Three charging strategies can be explored:

- **Immediate charging:** Vehicle owners plug their car in immediately when they arrive to their destination and begin charging at maximum power until the vehicle is completely charged

- **Delayed charging:** Vehicle owners do not immediately charge their vehicles when they arrive to a destination but rather charge their vehicle at the latest possible time such that they receive a full charge before they leave.
- **Smart charging:** Vehicle owners rely on a control signal to determine when the vehicle will charge. The control signal can take a variety of forms including a utility rate structure (i.e., \$/MWh), the Automatic Generation Control (AGC) signal from the grid (i.e., signal used to control regulation resources), or any other signal that can establish priority for charging at different times.

4.2.1.4. Vehicle Charging Profile Dispatch Optimization for BEVs

Constructing the charging profile for a pure battery electric vehicle (BEV) is very different from doing so for a plug-in hybrid electric vehicle (PHEV). For the latter, additional travel beyond the range of the battery capacity can be met by gasoline, which allows a consumer to continue using the vehicle in the same manner as a standard gasoline vehicle. The use of electric drive is preferred but it does not alter consumer travel patterns. For a BEV, however, consumer travel patterns may need to be changed to ensure that travel needs are met.

The optimal charging strategy considers an entire day's travel pattern and determines the optimal charging behavior based on a specific charging rate schedule that follows the net load demand of the electric grid. This differs from the above "non-optimal" methodology because it assumes complete knowledge of an entire day's travel and electricity price. This is not unreasonable in most cases as daily commutes are generally repetitive and electricity rates are currently published in advance.

The fundamental hypothesis is that drivers will adjust their charging behavior such that some objective can be achieved. In this case, the objective is the operating cost of PEVs, which mainly

includes the electricity cost for BEVs and additional gasoline cost for PHEVs. This concept can prescribe the infrastructure required for PEVs which is particularly important for BEVs that require a non-home charging infrastructure. The methodology assumes that EVSE is already available in prescribed locations. The optimal charging algorithm then outputs the locations that will be used during daily trips while minimizing charging costs. These locations then constitute the locations where EVSE should actually be installed. Although optimal charging has been implemented in previous studies [153-158], it has not been utilized to determine the locations for PEV infrastructure deployment. The method also serves as a baseline for the operating costs of non-optimal charging strategies.

Figure 103 shows a schematic diagram of the model. Optimization requires knowledge of the whole day's vehicle travel pattern and the charging cost during each dwelling activity, which can be provided by the NHTS data and the forecast for the net load demand, respectively. Given particular charging power limits, EVSE locations, battery capacity constraints, and energy conservation, the cost function can be minimized. The model outputs the location and duration of daily charging activity for each individual vehicle captured in the NHTS data. With the large and representative data set of NHTS, the summation of individual results is used to provide fleet-wide characteristics.

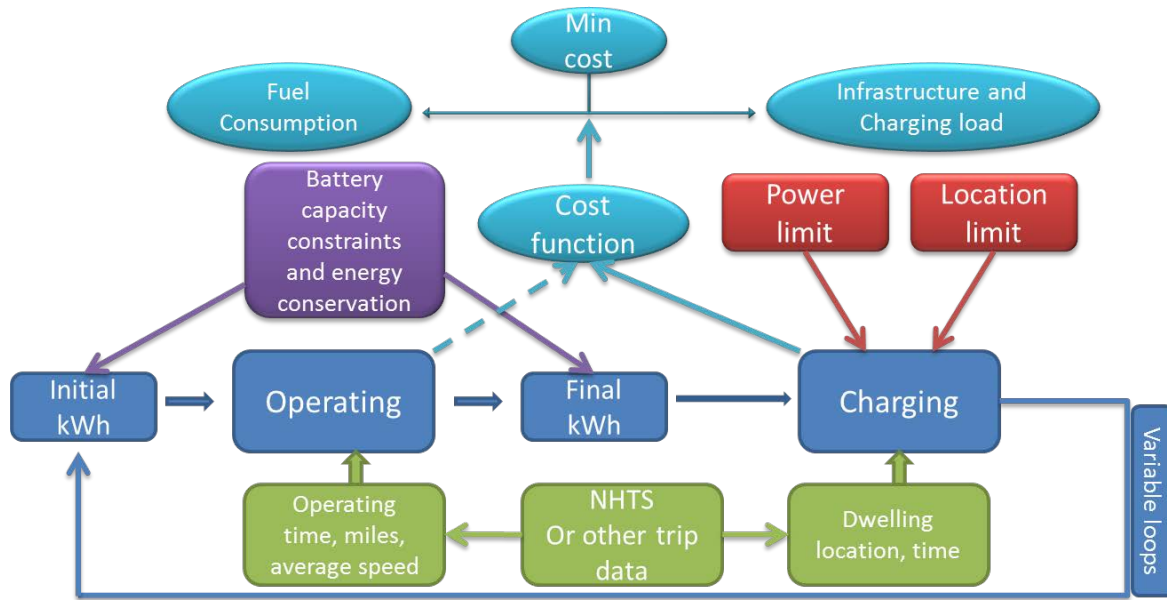


Figure 103 - PEV optimal operating and charging model.

Figure 104 shows an example of BEV battery charging and discharging energy throughout the course of one day. Solid red circles represent trip starting points while checkered black circles signify ending locations. For example, a vehicle may make m trips during the course of 24 hours (3 trips in the figure). The periods of battery state-of-charge (SOC) decrease (i.e., electricity consumption) are shown as $y_1, y_2, \dots, y_m$. Following each trip, a dwelling activity takes up a set of dwelling hours, indicated by $x_{m1}, x_{m2}, \dots, x_{m \text{ seg}(m)}$. The optimization problem solves for the accumulated stored battery energy in each hour during each dwelling activity, represented by x_{ij} , required to fulfill a day's driving at the lowest cost. The formation of the optimization is given below.

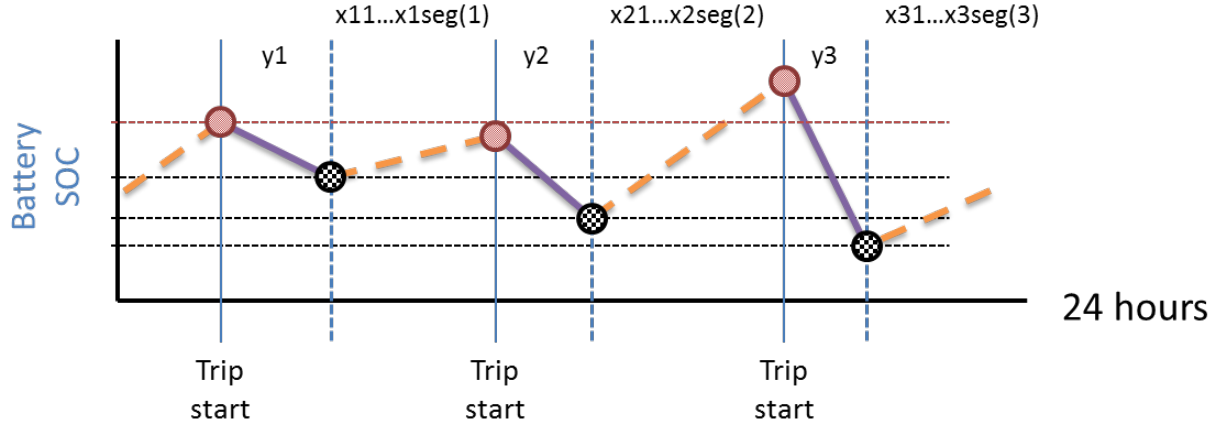


Figure 104 - Example of BEV optimal charging model.

The SOC increase (or electricity recharged) during the j^{th} hour in the i^{th} dwelling activity is given by x_{ij} . The summation of the total charging cost is given by:

$$\sum_{i=1}^m \sum_{j=1}^{seg(i)} f_{ij} \times x_{ij}$$

where, f_{ij} is the charging cost per kWh (DC) during the j^{th} hour in the i^{th} dwelling activity.

- The charging and discharging energy are assumed to be equal for 24 hours. Therefore, the energy conservation equality constraint is given by:

$$\sum_{i=1}^m \sum_{j=1}^{seg(i)} x_{ij} + \sum_{i=1}^m y_i = 0$$

- Inequality constraint: battery size. The window between the highest and lowest SOC points is not allowed to violate the battery size. In other words, as shown in Figure 104,

between any red circle (local maxima) and any black circle (local minima), the window has to be less than the battery capacity, (kwh). From each red circle, there are m inequality constraints, as shown in the equations below. Consequently, there are m^2 total constraints.

$$y_1 > -kwh$$

$$y_1 + \sum_{j=1}^{seg(1)} x_{1j} + y_2 > -kwh$$

$$y_1 + \sum_{j=1}^{seg(1)} x_{1j} + y_2 + \sum_{j=1}^{seg(2)} x_{2j} + y_3 > -kwh$$

.....

$$y_1 + \sum_{j=1}^{seg(1)} x_{1j} + y_2 + \dots + \sum_{j=1}^{seg(m-1)} x_{(m-1)j} + y_m > -kwh$$

The lower bound of x_{ij} is zero and the upper bound is a function of the following parameters.

- The charging power level at the specific location, derived from the charging location and power limits.

- The time span of available charging, fixed by the NTHS data. For instance, if the first hour in the first dwelling activity starts at 30 minutes past the hour, then the x_{11} equals 0.5.
- The AC to DC efficiency which is assumed to be a constant value in this study.

$$0 \leq x_{ij} \leq power_{ij} \times \Delta t_{ij} \times charging\ efficiency$$

An example of the charging optimization algorithm at work for a case with 60% BEV penetration, 46.8% base renewable penetration, and vehicles with a 200 mile range with 6.6 kW charging and home-based charging infrastructure is presented in Figure 105 and Figure 106:

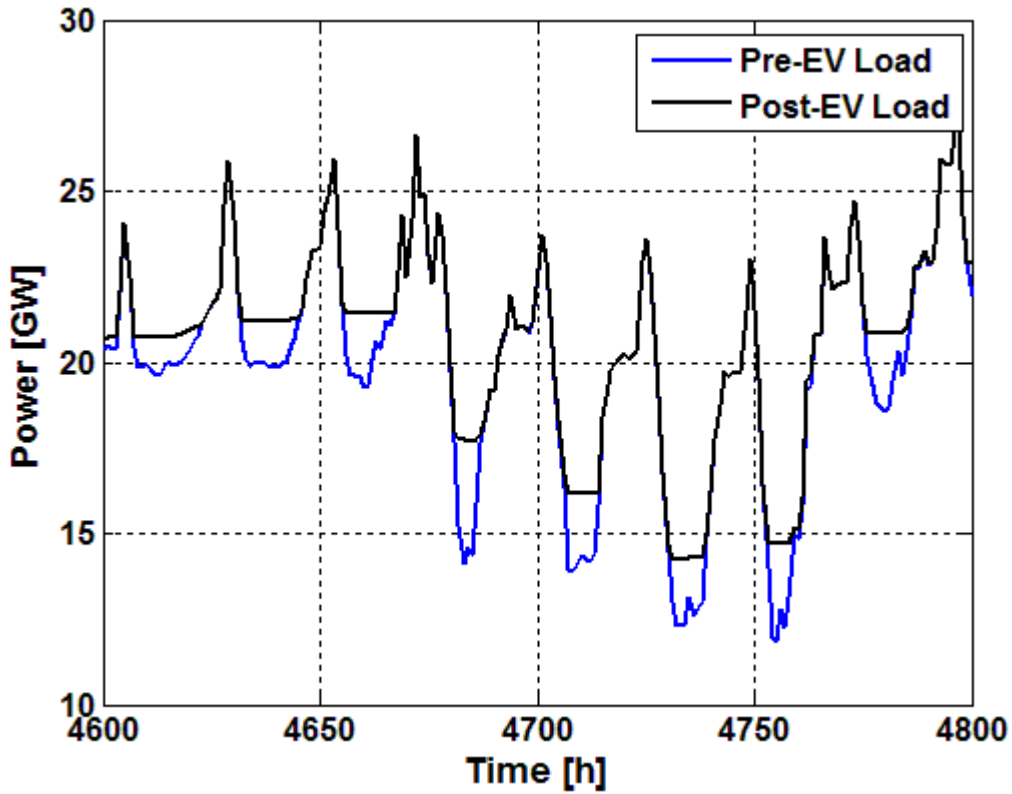


Figure 105 - BEV Optimal Charging Example (One Week): Pre- and Post- EV Grid Loads

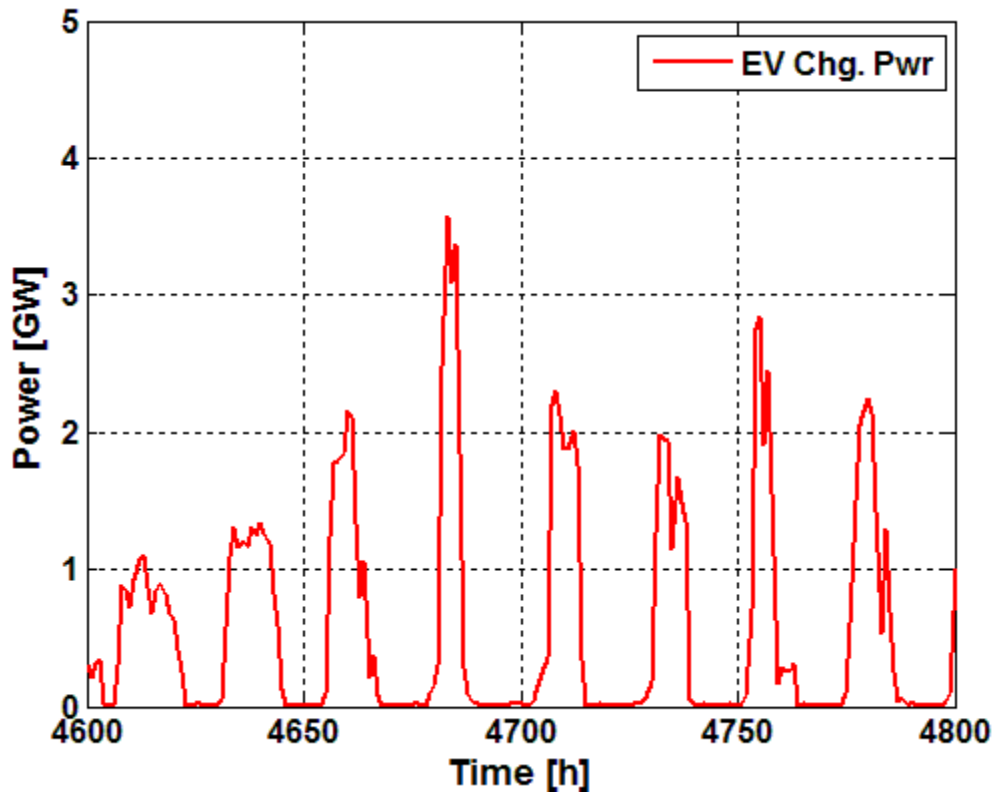


Figure 106- BEV Optimal Charging Example (One Week): Aggregate EV Charging Load

The electric vehicle charging load acts to smooth the net load demand on the electric grid to the extent possible. A large degree of smoothing is able to occur in this example, since the majority of vehicles are placed at residences during the hours of high wind power generation and low raw net load.

4.2.1.5. Calculation of Electric Vehicle Charging Infrastructure Costs

The large scale deployment of battery electric vehicles requires the installation of supporting infrastructure. Since electric vehicle charging is primarily a distribution-side load that connects to the electric grid at the lowest voltage levels, various system upgrades and the installation of specialized equipment is required to support these loads. These elements include but are not limited to charging cords, upgraded circuit capacities, electric boxes, and distribution transformer expansions, all of which have associated costs. Additionally, there exist potential costs

associated with hardware for communication and management of the charging load from the perspective of the utility or transmission grid operator. This section will give a brief overview of the relevant costs taken into account in this study.

The costs for installation of electric vehicle charging equipment and low-voltage circuit upgrades were obtained from the Plug-in Hybrid Electric Vehicle Charging Infrastructure Review by Idaho National Laboratory [159]. Although this report focuses on plug-in hybrid vehicles, the components required to charge battery electric vehicles are similar and the range of charging power used within this study is commensurate with those investigated in this study (Level 2 charging). The associated costs per installation for Level 2 charging in different residential settings are presented in Table 29:

Table 29 – Level 2 Electric Vehicle Service Equipment Cost per Installation

<u>Parameter</u>	<u>Value</u>
EVSE Level 2 Installation – Residential Garage	\$2,146
EVSE Level 2 Installation – Apartment Complex	\$1,520
EVSE Level 2 Installation – Commercial Building	\$1,852

Residential garages require the most retrofitting, since each household has its own isolated electric circuit. This is in contrast to apartment complexes and commercial buildings, where many electric components can be shared in a common electrical backbone. Therefore, EVSE costs for residential garages are higher than that of apartment complexes.

The majority of vehicles in California, however, are stored in residential garages. Approximately 81% of the vehicle-miles-traveled demand is sourced from vehicles residing in detached single

houses, and an additional 10% from townhomes with garages [62]. Therefore, the majority of charging installations will be installed in residential garages.

The key assumptions regarding assignment of EVSE costs are presented in Table 30:

Table 30 - EVSE Cost Parameters

<u>Parameter</u>	<u>Value</u>
Number of Vehicles per Installation	1
Residential Garage Fraction	91%
Apartment Complex Fraction	9%
EVSE Installation Lifetime	20 years

For home charging, the main assumption is that one charging station is to serve one PEV. To take into account charging stations that are not at home, the percentage of cars from the NHTS data that routinely spend long dwelling times at these alternate locations is extracted, and that fraction is added to the number of cars per charger. For example, if 45% of cars also dwell for long periods of time at the workplace, then each charging station serves 1.45 cars, with charging stations being present at work and home. Finally, the number of installations is calculated under the assumption that the vehicle miles traveled (VMT) penetration is equal to the vehicle population penetration. While due to differences in driving patterns for different types of light-duty vehicles exist, from the perspective of a fleet average, NHTS trip data shows the distribution of vehicle-miles-traveled and vehicle population is mostly similar [62].

The second category of electric vehicle infrastructure costs are associated with utility scale distribution circuit and transformer upgrades. The voltage and lifetime of distribution lines and transformers are sensitive to the magnitude of the peak load demand that these equipment must serve. Higher peak loads can cause voltage sags and degradation of equipment lifetime, which

can signify increased costs. This behavior is exacerbated in areas with high ambient temperatures that decrease the operating margin before reaching thermal limits.

Distribution circuit and transformer capacities are typically oversized upon installation on purpose in order to account for demand growth over the long design lifetime of the equipment and to address reliability concerns. Therefore, a margin for increased peak load due to electric vehicles is already present to some extent. More importantly, intelligent management of the charging profile through communication with the utility or independent system operator can prevent the electric vehicle charging load from adding to the peak load demand on distribution circuits in excess of contributions due to stationary load growth. Various studies have shown that the use of intelligent and communicative charging to place charging loads during the off-peak hours of the stationary load demand allows minimal impact on voltage deviation and transformer lifetimes [160-163]. Therefore, since the scenarios of this dissertation utilizes smart or optimal charging management strategies, the assumption is made that distribution circuit and transformer capacity upgrades in excess of those that would occur due to stationary load growth are negligible and the associated costs are also negligible.

4.2.2. Hydrogen Fuel Cell Vehicle Infrastructure Modeling

In order to capture the sensitivity of combined sector emissions and cost to the use of hydrogen fuel cell vehicles, it is important to capture both the environmental performance of the hydrogen infrastructure itself and that due to the effects it has on the electric grid and water supply sectors. The processes associated with hydrogen production, delivery, and dispensing all require energy in different forms, and produce emissions both in isolation and due to additional load placed on the electric grid. Additionally, some of these processes also contribute to water consumption.

Some of these processes can also be treated as dispatchable loads which can provide a benefit to the electric grid in terms of its ability to mitigate the effects of renewable variability.

In this context, the UCI-STREET model captures these effects through the Preferred Combination Assessment (PCA) tool [164]. The PCA tool has been developed at UCI with the aim of capturing all relevant effects.

4.2.2.1. Preferred Combination Assessment (Hydrogen Module for STREET)

The Preferred Combination Assessment (PCA) modeling approach was developed by the Advanced Power and Energy Program at the University of California, Irvine with Department of Energy Funding through the California Hydrogen Infrastructure Project (CHIP). The PCA methodology enables detailed calculation of criteria pollutant and greenhouse gas emissions, as well as total resource consumption (e.g., natural gas, water, diesel fuel) for a wide array of hydrogen generation, delivery, and dispensing scenarios. The PCA tool not only allows each potential supply chain to be assessed, but can analyze any mix of generation and supply strategies.

The hydrogen PCA model is utilized in the broader UCI-STREET model and serves the function of “hydrogen module”.

Many technology options exist to support the supply chain commencing with the production of hydrogen from a feedstock, to the distribution of hydrogen to fueling stations (as needed), to the dispensing of the hydrogen into a vehicle. The impact signature of a hydrogen infrastructure will vary widely depending on which technologies are used along the supply chain. Since transitioning to hydrogen will require substantial investments, it is important to understand, through advanced planning and modeling, the effects of different infrastructure scenarios.

Though previous studies have assessed either hydrogen production pathways [165-169] or vehicle and fueling station deployments [170-173], few have considered (1) the integration of a variety of technology options in a hydrogen supply chain, and (2) the mix of technology options in the context of deployment. The Preferred Combination Assessment (PCA) model, designed to analyze the impacts of an integrated hydrogen supply chain with respect to criteria pollutant emissions, greenhouse gas (GHG) emissions, water consumption, and energy utilization.

A systematic evaluation of a hydrogen infrastructure scenario must encompass the full scope of hydrogen deployment from a life cycle perspective. The PCA model operates on a lifecycle, or well to wheels (WTW), basis such that the generation, distribution, and utilization of hydrogen are integral to the analysis (Figure 107).

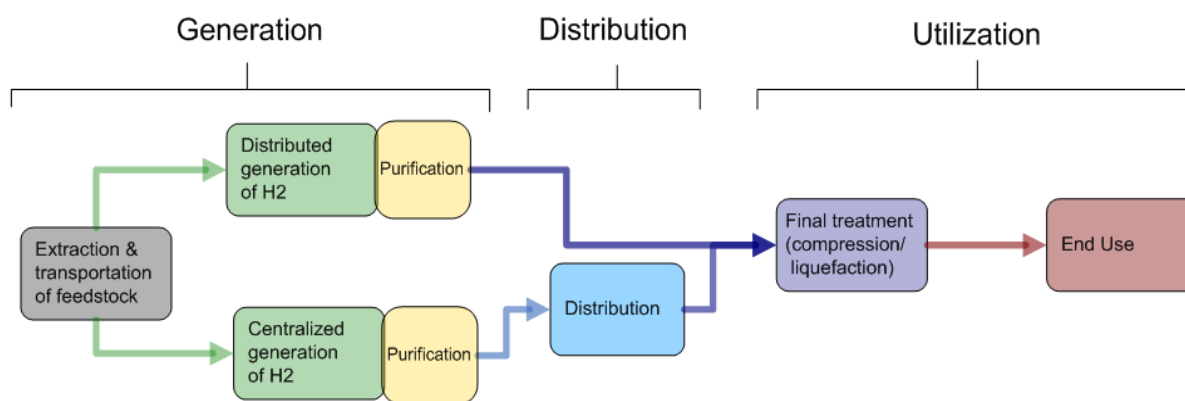


Figure 107 - WTW hydrogen infrastructure processes considered for impact assessment.

The PCA model integrates the variety of technologies and pathways for hydrogen into a comprehensive supply chain. The total demand for hydrogen in a region and the distances over which it must be delivered are two of the required inputs. Outputs include criteria pollutant emissions, GHG emissions, energy consumption, and water consumption. The model is also

compatible with existing cost analysis tools [174] providing as needed the opportunity to incorporate an economic examination. Figure 108 represents a simplified description of the model. The contribution by each technology option can be adjusted to explore how various permutations affect the outputs.

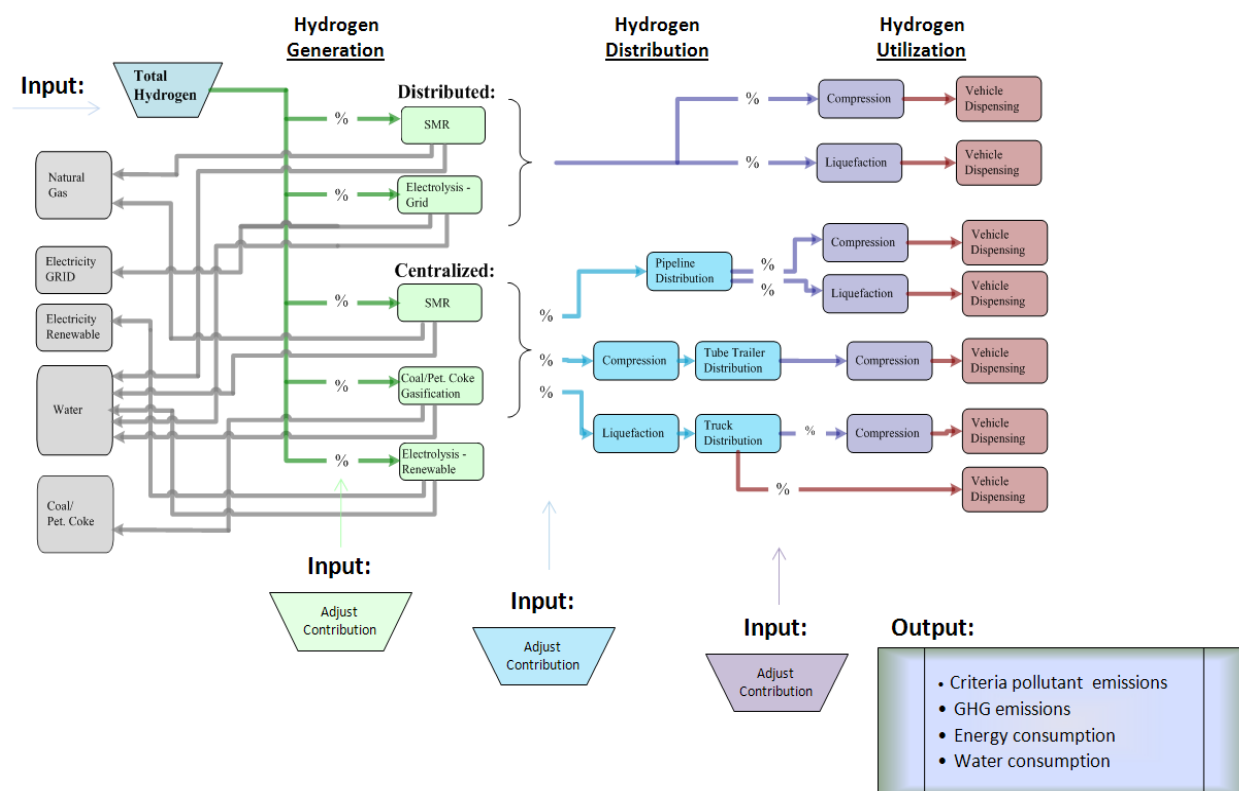


Figure 108 - Schematic of the PCA model (simplified).

The technologies that have been incorporated into the PCA model to date are catalogued in Table 31. Included are various technologies for hydrogen generation (on both a central and distributed scale), hydrogen distribution, and utilization (compression and dispensing). They are selected based on the likelihood of implementation, level of maturity, preparedness for the marketplace, and ability to meet infrastructure and regulation requirements [175-177]. The model is adaptable to including next generation technologies once maturation establishes (1) the viability for deployment, and (2) the impacts associated with deployment.

Table 31 - Technologies under consideration for hydrogen infrastructure assessment

HYDROGEN GENERATION	
<i>Feedstock extraction & transportation</i>	
Natural gas	
Water	
Electricity	
Petroleum Coke	
Coal	
<i>Strategy for conversion to hydrogen</i>	
<i>Centralized</i>	<i>Distributed</i>
SMR	SMR
Electrolysis	HTFC cogeneration with natural gas*
Petroleum coke (cogeneration)	Electrolysis
Coal gasification (cogeneration; CO ₂ sequestration)	
HYDROGEN DISTRIBUTION	
Truck - Tube trailer (2,500 psi pressurized gas)	
Truck - Tube trailer (7,500 psi pressurized gas)	
Truck - Liquid tanker	
Pipeline (gaseous hydrogen)	
HYDROGEN UTILIZATION (DISPENSING)	
350 bar (pressurized gas)	
700 bar (pressurized gas)	
Liquid hydrogen	
140 bar (pressurized gas)	

* HTFC cogeneration with natural gas refers to use of a high temperature fuel cell operating on natural gas feed to produce three useful products: electricity, heat, and hydrogen for use in vehicles.

The use of electrolysis for hydrogen production is treated as a highly dispatchable load, and the load profile produced by the electrolyzers is constructed in response to a cost function from the electric grid. This aspect of the model will be explained in detail in a later section.

It is also important to note that the temporal profile of the electric loads due to different elements is linked to the behavior of different parts of the system. The loads associated with the chemical methods of producing hydrogen and that associated with injection into the delivery system (truck, pipeline, etc...) are assumed to be flat in time, since these plants commonly operate at

steady state. By contrast, the loads associated with the dispensing of hydrogen (i.e. compression) at filling stations are tied to the profile of the hydrogen demand. The shape of hydrogen demand profile has been determined by paralleling the shape of the average gasoline dispensing profile as provided by [178], and scaled to match the aggregate hydrogen demand appropriately.

For each technology included in the model, emission factors are established for criteria pollutants and GHGs (Table 32). Energy and water consumption factors are also established for each technology. These factors serve as parameters in the model such that emissions and energy consumption outputs can be produced. The model provides the ability to adjust the contribution by each technology to the comprehensive supply chain allowing for the design of various infrastructure scenarios. It also takes into consideration the evolution of technologies over time, and changes in performance.

Table 32 - List of emissions species included in the hydrogen module.

<u>Emissions category</u>	<u>Pollutant</u>	<u>Abbreviation</u>
<i>Criteria pollutants</i>	Non-methane hydrocarbons	NMHC
	Carbon monoxide	CO
	Oxides of nitrogen (refers to both NO and NO ₂)	NO _x
	Oxides of sulfur (refers to SO ₂)	SO _x
	Total particulate matter	PM
<i>Greenhouse gases</i>	Carbon Dioxide	CO ₂
	Methane	CH ₄

Of the impact categories included in a full LCA [179, 180], four are addressed in the PCA model: (1) emission of criteria pollutants, (2) emission of greenhouse gases, (3) energy consumption, and (4) water consumption. Furthermore, the model incorporates the impacts associated with the operation of equipment on a WTW basis so that the entire supply chain of the fuel, from the extraction of a hydrogen feedstock to the end use, is included. The model does not include the impacts associated with the construction and decommissioning of hydrogen equipment.

4.2.2.2. Dispatch of Hydrogen Electrolysis and Hydrogen Storage

While many of the processes involved with the hydrogen infrastructure utilize electric energy, production of hydrogen through the use of electrolysis stands out as a major coupling between the transportation and electric grid sectors. Hydrogen electrolysis is the process of the hydrogen infrastructure that exhibits the largest flexibility in terms of the ability to produce a complementary load profile. Other processes tend to be relatively constrained in terms of the flexibility of their electric load profile. Dispensing and station loads are tied to demand profiles at hydrogen stations. The electric usage of chemical plants producing hydrogen (such as SMR) tends to be base-loaded since these chemical processes are designed to operate at steady state. Delivery methods such as pipelines also tend to operate at relatively steady state conditions, while liquid tanker and tube trailer delivery use primarily diesel fuel and their associated loads are constrained by delivery schedules.

The dispatchability of hydrogen electrolysis is also made possible by the fact that, contrary to plug-in electric vehicles, the production of hydrogen is temporally decoupled from demand at hydrogen stations due to the presence of storage. Electric vehicle charging must impose a load on the grid instantaneously during the period that vehicles are plugged in and are constrained by

consumer use preferences. Hydrogen production via electrolysis is only weakly subject to such constraints.

Therefore, the flexibility of the hydrogen electrolysis load allows it to be a key element in producing load profiles that can mitigate some of the undesirable impacts of renewable integration on electric grid operation. In this context, a model of the dispatch of these electrolyzers subject to constraints of storage and cost functions has been developed and is described here.

4.2.2.2.1. Electrolyzer Parameters

The representative electrolyzer model used for this model is the Norsk Hydro Atmospheric Type No. 5040 unit. This unit was selected due to its large scale size relative to other electrolyzer units, as compared with other electrolyzers investigated by NREL [181]. Other commercially available electrolyzer units tend to be small in size and would require a very large amount of units to produce hydrogen on the scale of the vehicle miles traveled demand for the state. The parameters of this particular unit have also been obtained from the NREL investigation and are presented in Table 33:

Table 33 - Electrolyzer Unit Parameters

<u>Parameter</u>	<u>Value</u>
Max Production Capacity	1046 kg/day H ₂
System Energy Requirement	53.5 kWh/kg
System Power Requirement	2.33 MW
Energy Efficiency	73%
Conversion Efficiency	80%
Output Pressure	435 psig
Water Input	485 kg/hr

The ramp rates of the electrolyzers are not considered as a constraint due to two primary reasons.

First, the timescale of the UCI-STREET model is hourly, with the analysis period being one year. Electrolyzer loads have been explored for use in providing frequency regulation and spinning reserve services to the electric grid by operating as a dispatchable load, and are regarded as a suitable candidate for that purpose [59]. The timescale of frequency regulation services includes ramping up and down on timescales from seconds to 5 minutes, which is significantly less than the 1 hour timescale of the UCI-STREET model. Therefore, the electrolyzers are considered to operate in a quasi-steady manner.

Second, although one of the largest electrolyzer units was selected, the size of a single unit is still very small compared to the scale of the hydrogen demand. For example to meet 10% of the vehicle-miles-traveled (VMT) demand with hydrogen electrolyzers requires 514 million kg H₂/year. A single unit in this case produces about 381,000 kg H₂/year, and a minimum of 1347 units would be required to meet the demand ***if the production profile was flat***. Considering that the analysis presented includes scenarios for very high VMT percentages met by hydrogen FCVs and the fact that the production profile is not flat, the actual amount of units required is considered to be very large. Additionally, electrolyzers are typically capable of operating over a large part-load range. Therefore, the electrolyzer load is considered to be continuous.

4.2.2.2.2. Electrolyzer Dispatch Algorithm

The dispatch of the electrolyzer fleet to produce complementary loads for the electric grid is carried out by using a variable moving window, exhaustive 1-D optimization approach, subject to the constraints of hydrogen storage size and in response to a cost function. For this application, an exhaustive 1-D optimization was found to converge to the same result faster than a formal optimization algorithm subject to the same constraints, although this may change in the future as additional constraints are added.

The algorithm proceeds as follows:

- Set initial fill level of bulk hydrogen storage
- Subtract yearly hydrogen demand profile from storage fill
- Record the hour immediately before the storage fill level becomes negative: t_{empty}
- Search backwards in time from t_{empty} to find the last hour when the storage fill level was at maximum capacity: t_{full}
 - If the storage fill level was never at maximum capacity, t_{full} is set to the first hour of the year
- Optimization window is from t_{full} to t_{empty} . Within optimization window, examine the cost function and find the time point with the lowest function value.
 - If adding electrolyzer increment will overfill storage at selected point, exclude point
 - An electrolyzer must be activated in this time window to prevent violating fill constraints.
- Add a given amount of electrolysis load at optimal point
- Update hydrogen storage fill profile and cost function profile
- Repeat until end of year is reached.

An example of a single step of the optimization approach is presented in Figure 109:

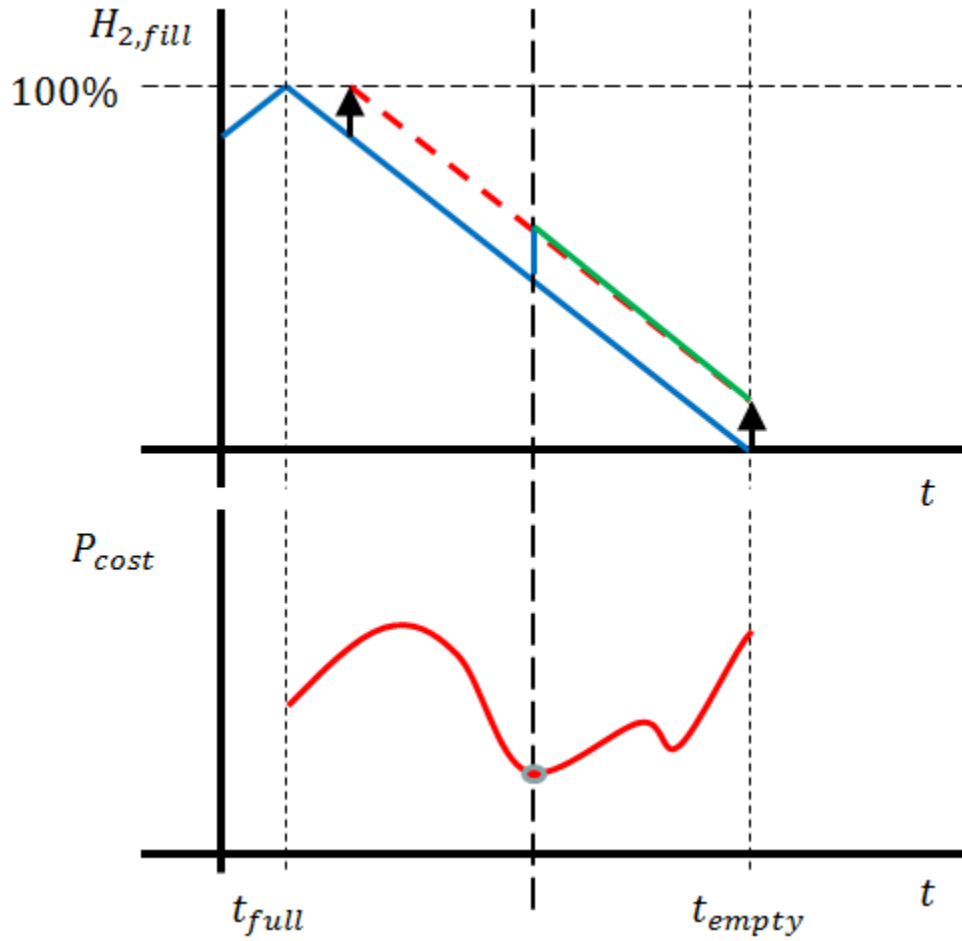


Figure 109 - One Step of the Optimization Algorithm

This simple algorithm produces an electrolysis load profile that responds to the value of the input cost function within constraints.

The cost function used in this model is based on the net electric load on the electric grid after less flexible complementary technologies have been applied and is updated in-situ as electrolyzer increments are added:

$$P_{Cost} = P_{load} - P_{Ren} - P_{hydro} - P_{DR} + P_{PEV} + P_{H2,nondis} + P_{H2,inc}$$

Where:

- P_{cost} = Cost function value: net load profile entering electrolysis module
- P_{hydro} = Profile of load subtracted due to non-renewable hydropower generation
- P_{ren} = Profile of load subtracted due to aggregate renewable generation profile
- P_{DR} = Profile of load removed due to demand response
- P_{PEV} = Profile of load added due to PEV charging
- $P_{\text{H2,nondis}}$ = Profile of load added due to non-dispatchable hydrogen loads
- P_{H2inc} = Profile of hydrogen electrolysis load. Updated in-situ until optimization ends

The effects of demand response and electric vehicle charging are embedded in the cost function since in the electric grid model, the complementary technologies are ordered from least flexible to most flexible. This arrangement is used to prevent the operation of one dispatchable technology from undoing the benefits of other complementary technologies and is more similar to how these technologies would be dispatched by the system operator.

For this particular analysis, however, the use of plug-in electric vehicles and hydrogen vehicles in the holistic scope are considered separately from each other.

This cost function causes the hydrogen electrolyzers to produce a load profile such that load is added when the net load demand is low, and load is refrained from being added to the extent possible when the net load demand is high. This results in a relative valley-filling strategy, which addresses the fact that the locations of the load valleys are constantly changing in time due to renewable generation. An example of the algorithm at work for a case with 5% FCVs, 46.8%

base renewable penetration level, and zero contribution from SMR production is presented for the span of one week in Figure 110,

Figure 111 and Figure 112.

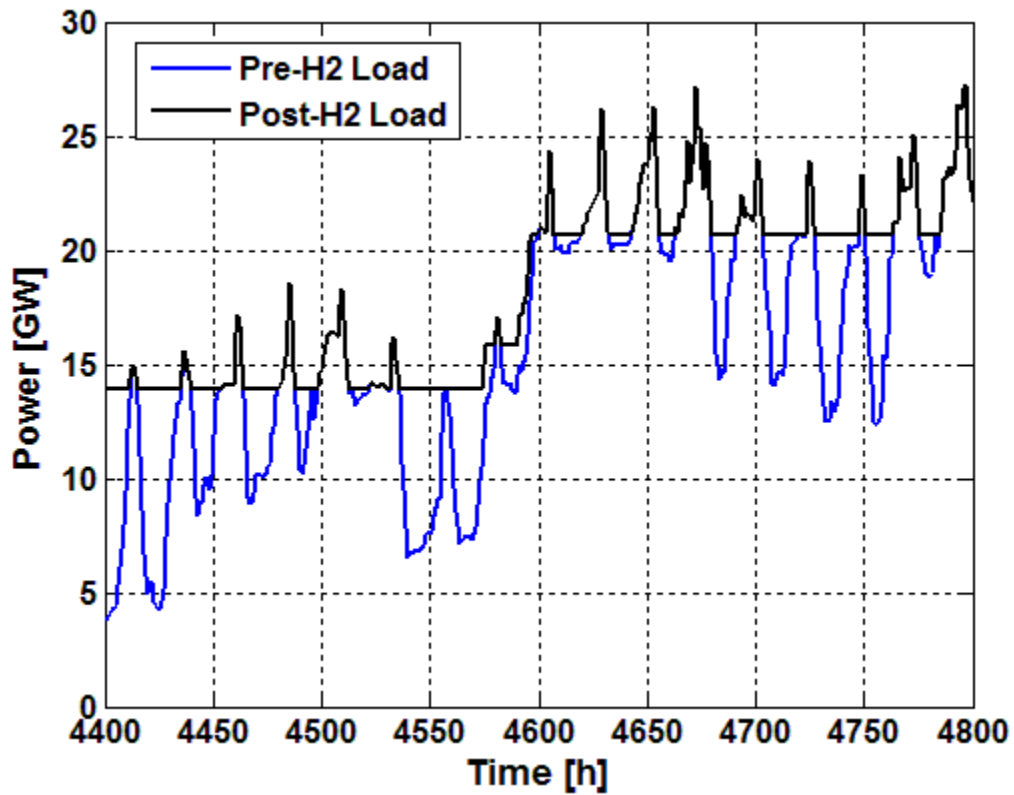


Figure 110 – Example Pre- and Post-H2 Electrolysis Net Load Profiles (One Week)

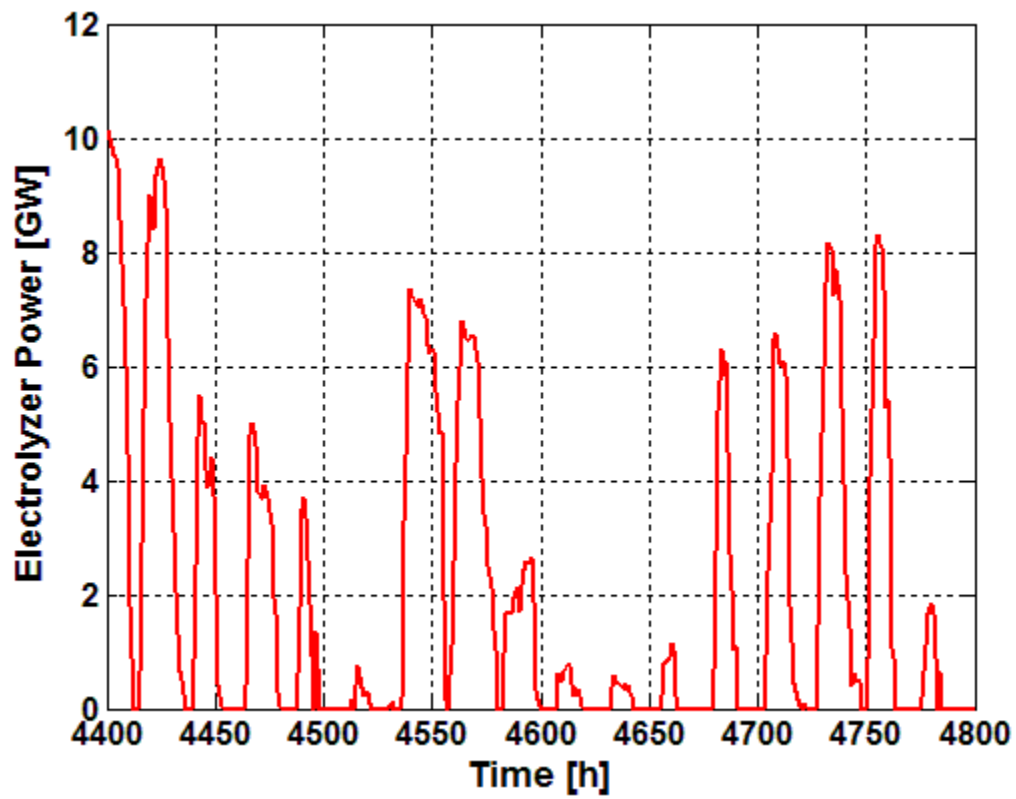


Figure 111 - Example Electrolyzer Fleet Power (One Week)

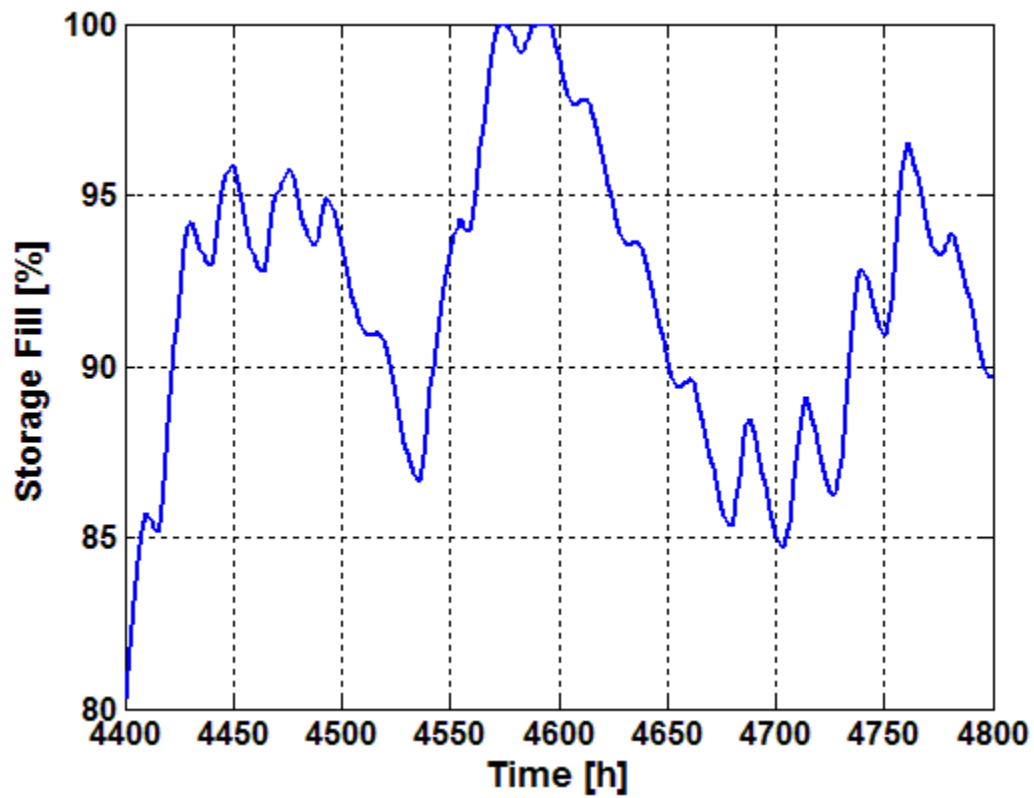


Figure 112 - Example Storage Fill Profile (One Week)

The algorithm acts to smooth the net load profile as much as possible to reduce the burden on the operation of balancing generators, while remaining within storage constraints.

4.2.2.2.3. Hydrogen Storage System

The hydrogen storage system was modeled by paralleling the structure of the natural gas storage system in California. Since hydrogen will be a bulk gas that is not instantaneously made available to demand at hydrogen stations in the case of centralized production, storage will need to be present to match supply with demand. This storage system consists of stationary chambers, storage at stations themselves, and storage in the transport vessels or pipeline used to deliver hydrogen. All of these elements are similar to the natural gas storage system in California.

For this model, the hydrogen storage system includes an aggregate of all elements that store hydrogen, and is treated as a bulk system. While the nature of the system is diverse, the scale of the system warrants that tracking the details of a produced quantity of hydrogen in the supply chain is unnecessary and does not have much bearing on the overall results of the study.

Therefore, any hydrogen that is produced is injected into the bulk system, and any hydrogen that is dispensed is extracted from the same system.

In California, the natural gas storage system has a firm working capacity of about 177.1 billion cubic feet (Bcf) of capacity [112], including 135.1 Bcf in Southern California and 42 Bcf in Northern California as of 2010. The natural gas consumption for the state for the years 2007-2011 has been determined by the EIA [182] and is presented as follows:

Table 34 - CA Total Natural Gas Consumption 2007-2011

<u>Year</u>	<u>Annual Natural Gas Demand (Bcf)</u>
2007	2395
2008	2405
2009	2328
2010	2273
2011	2153
Average	2311

Comparing the ratio of firm working storage capacity for natural gas to the average annual natural gas demand for the state, the storage capacity is approximately 7.7% of the annual natural gas demand. Therefore, the hydrogen storage system was sized based on a similar ratio: 7.7% of annual hydrogen demand.

The fill level of the hydrogen storage system is determined at each hour within the electrolyzer dispatch model according to the following:

$$H2_{fill}(t) = \frac{H2_{elec}(t) + H2_{non-elec}(t) - H2_{demand}(t)}{H2_{stor,max}} \times 100$$

Where:

- $H2_{fill}$ = Fill percentage of storage system [kg]
- $H2_{elec}$ = Hydrogen contribution from electrolysis [kg]
- $H2_{non-elec}$ = Hydrogen contribution from non-electrolysis sources (SMR, etc...) [kg]

- $H2_{demand}$ = Hydrogen demand due to dispensing at stations [kg]
- $H2_{stor,max}$ = Maximum hydrogen storage capacity [kg]

4.2.2.3. Determination of the Hydrogen Demand

The annual hydrogen demand is determined from the fuel cell vehicle penetration of the vehicle-miles-traveled demand and the efficiency of the aggregate fuel cell vehicle fleet (in mi/kg) according to the following:

$$\sum H2_{demand} = \frac{\sum VMT}{\eta}$$

Where:

- $\sum H2_{demand}$ = annual hydrogen demand [kg]
- $\sum VMT$ = annual vehicle-miles-traveled [mi]
- η = fuel cell vehicle fleet efficiency [mi/kg]

The annual vehicle miles traveled for the state was obtained from the EMFAC model utilized by the California Air Resources Board [151] for the year of consideration.

4.2.2.4. Calculation of Hydrogen Infrastructure Costs

The infrastructure that will be required to support the use of hydrogen fuel cell vehicles encompasses many components which have associated costs to construct, install, and maintain. These costs will manifest themselves not only in the price of a unit of hydrogen, but also as an important component of the overall cost to provide energy to the consumer. This section

describes the data sources and methods used to calculate the total cost of the required supporting hydrogen infrastructure for each case and its contribution to the total holistic system cost.

4.2.2.4.1. Hydrogen Production Costs

The analyses in this dissertation considers two primary hydrogen production methods: Water Electrolysis and Steam Methane Reformation. A description of the cost methodology for these components is described as follows.

The costs associated with Water Electrolysis were calculated using the H2A Future Central Hydrogen Production from Grid Electrolysis Version 3.0 model provided by the U.S. Department of Energy [183], with slight modification. The use of centralized electrolysis cost models is more appropriate for this study given the large scale nature of the infrastructure being deployed and the long time horizon available to accomplish this deployment. This model takes into account:

- **Capital costs** including purchase of the electrolyzer units, plant construction, permitting, licensing, and land use.
- **Fixed operation and maintenance costs** including full time staff labor, material cost, renewable of licenses and fees, and repairs/decommissioning.
- **Variable operation and maintenance costs** including miscellaneous material costs and feedstock costs.

The model takes primary inputs of electrolyzer plant capacity factor and plant size, as well as other secondary inputs for financial parameters. The default parameters for unit costs are based on that required for an electrolyzer plant composed of 50 Norsk Hydro electrolyzer units. For this study, the following key input parameters are used:

Table 35 - Key Parameters for Calculating Electrolyzer Costs

<u>Parameter</u>	<u>Value</u>
Number of Electrolyzers per Plant	50
Single Plant Capacity	52,300 kg H ₂ /day
Reference Year (for inflation calculations)	Year 2005 Dollars
Construction Period	2 Years
Plant Life	40 Years
Electricity Cost	Dynamic (see description)
Electrolyzer Capacity Factor	Dynamic (see description)

The primary output of the model is the contribution of hydrogen production from water electrolysis to the cost of a unit kilogram of hydrogen, with the individual contributions from capital costs, decommissioning costs, operation and maintenance costs, and feedstock costs explicitly presented.

The H2A model takes in electricity price and electrolyzer capacity factor as a static input. With the UCI-STREET model, however, the capacity factor of the electrolyzer fleet and the cost of electricity are calculated dynamically for each case, depending on the time-resolved operating profiles and characteristics of each technology. These effects are important to capture to fully realize the synergies or interferences between technologies in the context of the holistic system. To account for these effects, the following methods are used.

To allow a dynamic electricity cost, the feedstock cost contribution of electricity to the overall hydrogen unit cost is subtracted out from the H2A model result and electricity costs are calculated separately. The electricity usage associated with hydrogen electrolysis is a known quantity for each case, calculated from the PCA and electrolyzer dispatch models. The total

hydrogen demand is known and the electricity price due to grid operation and design is calculated for each case. With these parameters, the electricity feedstock cost is calculated external to H2A using the dynamically changing electricity cost output from HiGRID and subsequently added back into the total system cost.

To allow a dynamic electrolyzer capacity factor, a spanning study of the H2A model output was conducted to determine the hydrogen cost contribution as a function of electrolyzer capacity factor. This produced a table for the hydrogen unit cost contribution of central electrolysis (with electricity feedstock costs subtracted out) as a function of electrolyzer fleet capacity factor, as presented in Table 36:

Table 36 - Hydrogen Unit Cost Contribution from Electrolysis w/Electricity Feedstock Removed

<u>Electrolyzer Plant Capacity Factor (%)</u>	<u>Hydrogen Cost Contribution w/o Electricity Feedstock Cost (\$/kg)</u>
1	53.52095682
2	26.81607617
3	17.91444928
4	13.46363584
5	10.79314777
6	9.012822393
7	7.741161409
8	6.787415671
9	6.045613431
10	5.452171638
12	4.56200895
14	3.926178458
16	3.449305589
18	3.078404469

20	2.781683572
22	2.53891193
24	2.336602228
26	2.165417096
28	2.018686982
30	1.891520884
32	1.780250548
34	1.682070839
36	1.594799987
38	1.516715541
40	1.446439539
42	1.38285649
44	1.325053718
46	1.272277274
48	1.223898867
50	1.179390733
52	1.138306301
54	1.10026516
56	1.064941244
58	1.03205346
60	1.001358195
62	0.97264327
64	0.945723027
66	0.920434314
68	0.896633173
70	0.874192097
72	0.852997747
74	0.832949038

76	0.813955524
78	0.795936036
80	0.778817523
82	0.762534059
84	0.747025998
86	0.732239243
88	0.718124612
90	0.704637299
92	0.69173639
94	0.679384457
96	0.667547187
98	0.656193071
100	0.64529312

The calculated electrolyzer capacity factor from the electrolyzer dispatched model is then used to determine the electrolyzer cost contribution in each case.

The costs associated with steam methane reformation were calculated using the H2A Future Central Hydrogen Production from Natural Gas without CO₂ Sequestration Version 3.0 model provided by the U.S. Department of Energy [184], with slight modification. Similar to the model for calculating costs due to hydrogen electrolysis, this model takes into account capital costs as well as fixed and variable operation and maintenance costs associated with maintaining a large scale natural gas fueled steam methane reformation plant. This model also takes in primary inputs of plant operating capacity factor and plant capacity, as well as secondary financial inputs.

In contrast to electrolyzer operation, however, steam methane reformation plants tend to operate in a steady-state manner. In this study, steam methane reformation plants operate with a flat

hydrogen production and therefore resource consumption profile in each case. Therefore, a single capacity factor is assumed for each plant. The key inputs for the H2A steam methane reformation model are as follows:

Table 37 - Key Parameters for Calculating Steam Methane Reformation Costs

<u>Parameter</u>	<u>Value</u>
Single Plant Capacity	379,387 kg H2/day
Reference Year (for inflation calculations)	Year 2005 Dollars
Construction Period	3 Years
Plant Life	40 Years
Plant Capacity Factor	90%
Electricity Cost	Dynamic (see description)

All of the input parameters are set to their default value except for the reference year and the electricity cost. The use of a dynamic electricity cost is handled in the same manner as that for electrolysis described previously. The primary output is the hydrogen unit cost contribution of steam methane reformation in dollars per kilogram of hydrogen dispensed.

4.2.2.4.2. Delivery and Dispensing Costs

Another major component of the hydrogen infrastructure is the delivery of produced hydrogen to hydrogen stations and the dispensing of hydrogen to vehicles at these stations. The methodology for computing these costs, their contribution to the unit cost of hydrogen, and total system costs is presented here.

Once hydrogen is produced from electrolysis or steam methane reformation, it is typically delivered via three primary methods:

- **Gaseous Truck:** This involves the compression of gaseous hydrogen to high pressures and storage in gas tubes. These tubes are then transported from production plants to hydrogen stations via a fleet of heavy-duty diesel trucks. Necessary components are as follows:
 - Gaseous hydrogen terminal and compressor
 - Tube storage and heavy duty trucks
- **Liquid Tanker:** This involves the liquefaction of originally gaseous hydrogen and storage in liquid tanks. These tanks are then transported from production plants to hydrogen stations via a fleet of heavy-duty diesel trucks. Necessary components are as follows:
 - Liquid tanks and heavy duty trucks
 - Liquefier
 - Liquid loading terminal for trucks
- **Gaseous Pipeline:** This involves the construction of a pipeline network through which gaseous hydrogen is pumped from production stations to city terminals (transmission), and subsequently to hydrogen stations (distribution). Necessary components are as follows:
 - Transmission Pipeline
 - Distribution Pipeline
 - Central and Motive Compressors

Each of these components uses various forms of energy and emits various levels of greenhouse gases, which are taken into account in the PCA model.

Additionally, once hydrogen is delivered to a hydrogen station, it is typically dispensed into vehicles at two common pressures: 350 bar and 700 bar. The use of the latter may allow a vehicle to store a larger mass of hydrogen for increased range in heavy vehicles, but requires additional infrastructure for compression of stored hydrogen to these pressures. Costs associated with the construction of the hydrogen refueling station itself must also be taken into account.

The contribution to the unit cost of hydrogen vehicle fuel for these different configuration pathways is calculated by use of the Hydrogen Delivery Scenario Analysis Model (HDSAM), version 2.3.1, for Future deployments, provided by the U.S. Department of Energy [185], with slight modification. This model allows the calculation of the hydrogen unit price in dollars per kilogram dispensed based on the designation of an urban, rural, or combined market, vehicle penetration, delivery mode, dispensing mode, refueling station size and storage option.

Additionally, inputs to characterize the area where the infrastructure is being built are used, such as road segment length, city population, station distance from highways, and population density.

For this study, the following inputs to the HDSAM model are used as common in all scenarios. Differences between scenarios will be described in Section 3, which outlines the scenario development for analysis.

Table 38 - Key Inputs for HDSAM Model

<u>Parameter</u>	<u>Value</u>
FCV Market Type	Combined Urban and Rural
Gaseous Truck Average Delivery Distance	50 miles
Liquid Tanker Average Delivery Distance	100 miles
Transmission Pipeline Average Delivery Distance	300 miles
Daily H2 use	Set by Vehicle Penetration and VMT
Vehicle Penetration	0 – 60 %
Electricity Cost	Dynamic (see description)
FCV Fuel Economy	54 mi/kg
Dispensing Mode	350 bar or 700 bar: Gaseous
Refueling Station Nominal Capacity	1500 kg/day

The areas where fuel cell vehicles are likely to be deployed, such as Los Angeles and the Orange County areas for example, are used as the representative cities modeled in the HDSAM model. These spatial models are used to calculate the distribution pipeline requirement.

The methodology used in this study applies slight modifications to the HDSAM output.

The first modification is to allow the use of a dynamic electricity cost as calculated by the HiGRID model. This is handled in the same manner as that for steam methane reformation and water electrolysis. The electricity feedstock cost is subtracted out from the HDSAM output, calculated separately from the usage values from the PCA model and the electricity cost from the HiGRID model, and added back in. This allows the effect of all technologies on the bulk cost of electricity to be propagated throughout the system and capture synergies or interferences between technologies.

The second modification is the removal of the calculated storage cost. In addition to the need for availability of hydrogen at refueling stations, this model also considers the use of hydrogen storage not only for this purpose but also to assist in the electric load shaping capabilities of water electrolysis. Therefore, the storage sizes considered in the study are different than that considered in the HDSAM model. The storage cost contribution is removed from the HDSAM model output, and calculated separately. This will be described in the storage modeling section.

4.2.2.4.3. Hydrogen Storage Costs

The sizing of the bulk hydrogen storage system for this model was previously described along with the electrolyzer fleet dispatch algorithm. Due to the large scale nature of the infrastructure being deployed in this analysis, the storage system is assumed to be large scale and to make use of large scale gaseous storage mediums in the same manner as that of the natural gas infrastructure. The hydrogen storage system is assumed to be composed primarily of geologic storage forms, such as salt caverns and depleted oil fields, with an associated cost as follows [186]:

Table 39 - Storage Cost Parameters

Parameter	Value
Geologic Storage Contribution to Hydrogen Cost	0.30 \$/kWh
Storage System Lifetime	40 years

This value, among others in the literature, designates the cost of hydrogen storage on a per-kWh basis since these systems were studied for use as a form of electric energy storage on the grid. This value is converted to a cost per kilogram of hydrogen dispensed as follows:

$$C_{storage} = Stor_{unit\ cost} \cdot E_{H2,equiv} \cdot \frac{S_{size}}{H2_{demand}}$$

Where

- C_{storage} = cost of storage system per unit of hydrogen dispensed [\$/kg H₂ dispensed]
- $\text{Stor}_{\text{unit cost}}$ = cost of hydrogen per kWh capacity [\$/kWh]
- $E_{\text{H}_2, \text{equiv}}$ = energy equivalent of a kilogram of hydrogen [kWh/kg H₂ capacity]
- S_{size} = capacity of hydrogen storage system [kg H₂ capacity]
- $\text{H}_2_{\text{demand}}$ = Annual hydrogen demand [kg H₂ dispensed]

It is important to differentiate between the cost contribution per kilogram of hydrogen stored and that per kilogram of hydrogen dispensed, since only a portion of the hydrogen demand passes through the storage system and contributes to the hydrogen storage capacity. This conversion allows the hydrogen storage values to be used on a per-kilogram-dispensed basis, consistent with all of the other cost calculations.

Additionally, the storage system is primarily a one-time cost which is financed over the lifetime of the system. Therefore, the entire cost of the system need not be paid during a single year, and is therefore amortized over the lifetime of the system.

4.2.3. Gasoline Vehicles

In this dissertation, there is no case where all of the vehicle-miles-traveled demand is met by hydrogen fuel cell vehicles or plug-in electric vehicles. Therefore, emissions and costs are still present due to the combustion of gasoline fuel. These emissions can be separated into two categories: upstream emissions due to fuel extraction and delivery (well-to-tank: WTT), and operating emissions due to fuel combustion (tank-to-wheel: TTW).

The WTT emissions were obtained from the GREET model [76], utilizing a pathway for oil extraction, refining, and delivery. The TTW emissions were obtained using emissions factors and fleet fuel economy from the CARB EMFAC model [151]. All factors are used for the test year of 2005. The factors utilized are as follows:

Table 40 - GHG Emission Factors for Gasoline Vehicles

<u>Parameter</u>	<u>Value</u>
Well-to-Tank GHG Emissions	80 g CO ₂ e/mile
Tank-to-Wheel GHG Emissions	390 g CO ₂ e/mile

The costs associated with the operation of gasoline vehicles are based upon the use of a gasoline fuel price. The gasoline fuel price includes the costs of extraction, refining, delivery, dispensing, and profit margin implicitly, and therefore is used to represent gasoline usage and infrastructure costs. The gasoline fuel price, however, additionally includes other factors such as state and federal fuel taxes which are charged to the consumer but are not a technical contributor to the cost of providing gasoline. Therefore, factors such as state and federal taxes are subtracted from the gasoline price used.

This study uses the annual average gasoline price provided by the U.S. Energy Information Administration for California for the year 2012 [187]. While the test year for the analysis is 2005, gasoline prices have changed significantly between 2005 and 2012 due to factors other than inflation. Therefore, the price of gasoline for 2012 was used, but a deflation curve was applied to obtain the equivalent price in year 2005 dollars.

With all of these factors taken into account, the gasoline cost used in this study is as follows [145]:

Table 41 - Gasoline Costs

<u>Parameter</u>	<u>Value</u>
2012 California Average Annual Price	\$4.08
State Excise Tax	\$0.36
Federal Excise Tax	\$0.18
2012 Gasoline Cost without Taxes	\$3.54
Equivalent Gasoline Cost in Year 2005 Dollars	\$3.01

The gasoline usage is calculated based on the remaining VMT that is not met by either fuel cell vehicles or electric vehicles. While projections exist for the progression of the cost of gasoline in the future, these projections were not utilized in this study. The approach of using a single gasoline price was taken such that the sensitivity of the combined system performance to the implementation of alternative vehicle types could be examined explicitly. The price of gasoline has also been historically difficult to predict, therefore for future cases it is held constant.

4.3. Water Supply Sector

To accomplish the objective of determining the scale of available options to stabilize major reservoir levels and therefore the water supply, an integrated modeling platform was developed. A general layout of the water supply sector model and its interfaces with the broader STREET model is presented in Figure 113:

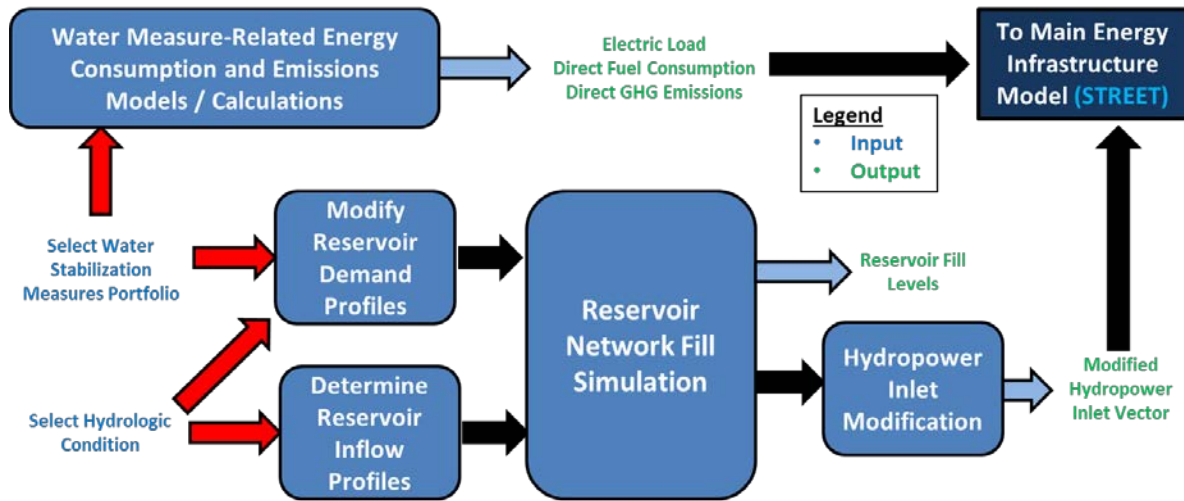


Figure 113 – UCI-STREET Water Supply Sector Module

This includes two major classes of components: 1) a model of major surface reservoir behavior and their network and 2) modeling and characterization of the behavior and potential for different water supply stabilization measures in the state. Each of these components will be described as follows.

4.3.1. Individual Reservoir Model

Before the reservoir network is modeled, the behavior of the individual reservoir dispatch must be captured. A simple model for an individual reservoir that takes inputs of temporally resolved inflow, temporally resolved reservoir demand, initial fill level, maximum discharge rate, and minimum/maximum fill level limits is used. The fundamental concept of the model is based on a monthly reservoir model introduced by van Beek [188], Haddeland [189], and Hanasaki [190]. For a given time step, the model is described as follows.

The reservoir storage state is defined by:

$$S_i = S_{i-1} + \int_{i-1}^i \dot{Q}_{in} - \dot{Q}_{out} - \dot{Q}_{add}$$

Where $\dot{Q}_{in}$ represents the introduced inflow. $\dot{Q}_{out}$ represents the reservoir release to meet the demand, which is calculated as follows:

$$\dot{Q}_{out} = \max(\min(\dot{Q}_d, \dot{Q}_{lim}), F(s) * \dot{Q}_{avg})$$

$\dot{Q}_{lim}$ is the limit on the amount of discharge available, limited by the amount of water stored.

$\dot{Q}_{avg}$ is the average inflow for the entire dataset. $\dot{Q}_d$ represents the reservoir release to meet the reservoir demand only:

$$\dot{Q}_d = \min\left(1, \frac{S_{i-1}}{S_{min}}\right) * Demand_i$$

$F(s)$ represents the ratio of the potential release relative to the amount stored at the given time step:

$$F(s) = \min\left(1, \max\left(0, \frac{S_{i-1} - S_{min}}{S_{max} - S_{min}}\right)\right)$$

$\dot{Q}_{add}$ represents the additional release from the reservoir for auxiliary concerns such as flood and river level management, considering the available buffer between maximum operating fill level and maximum absolute fill capacity:

$$\dot{Q}_{add} = \max\left(0, \frac{S_{i-1} - S_{min}}{S_{max} - S_{min}}(\dot{Q}_b - \dot{Q}_{out})\right) + \max(0, S_{i-1} - S_{min})$$

Where $\dot{Q}_b$ is the bank-full discharge.

This process is carried out sequentially for every time step in the dataset for the analysis period.

More details on the datasets will be described in a later section.

4.3.2. Reservoir System Model

A model of California's reservoir system is developed to capture the sensitivity of deploying different technologies in hydrologic regions of the state. California is selected as the system of interest due to its many unique characteristics, including a high population, a diverse array of water demands, spatially diverse precipitation patterns, and a highly managed water conveyance system. This model captures 13 major surface reservoirs: 12 are managed by the California Department of Water Resources and Lake Mead. The included surface reservoirs and their capacity are presented in Table 42 with their locations presented in Figure 114:

Table 42 - Major Surface Reservoirs Managed by CA DWR + Lake Mead. Designation of the hydrologic region directly served by the each reservoir and their connection to the Sacramento Delta is included.

<u>Reservoir</u>	<u>Capacity (TAF)</u>	<u>Hydrologic Region Directly Served</u>	<u>Connection to Delta</u>
Don Pedro (DP)	2030	San Joaquin River San Francisco Bay	Tuolumne River
Exchequer (EX)	1025	San Joaquin River San Francisco Bay	Merced River San Joaquin River
Folsom Lake (FS)	977	San Joaquin River	American River
Millerton Lake (ML)	520	Tulare Lake South Lahontan	San Joaquin River
New Melones (NM)	2420	San Joaquin River San Francisco Bay	Stanislaus River
Lake Oroville (OR)	3538	Sacramento River	Feather River
Pine Flat (PF)	1000	Tulare Lake South Lahontan	San Joaquin River
Lake Shasta (LS)	4552	North Coast Sacramento River	Sacramento River
Trinity Lake (TL)	2449	North Coast Sacramento River	Sacramento River
San Luis (SL)	2039	Central Coast San Francisco Bay	State Water Project (Supply)
Lake Mead (CA Effective) (LM)	10867	South Coast Colorado River	N/A
Castaic Lake (CL)	325	South Coast	N/A
Pyramid Lake (PL)	171	South Coast	N/A
CA Statewide Aggregate	31913		

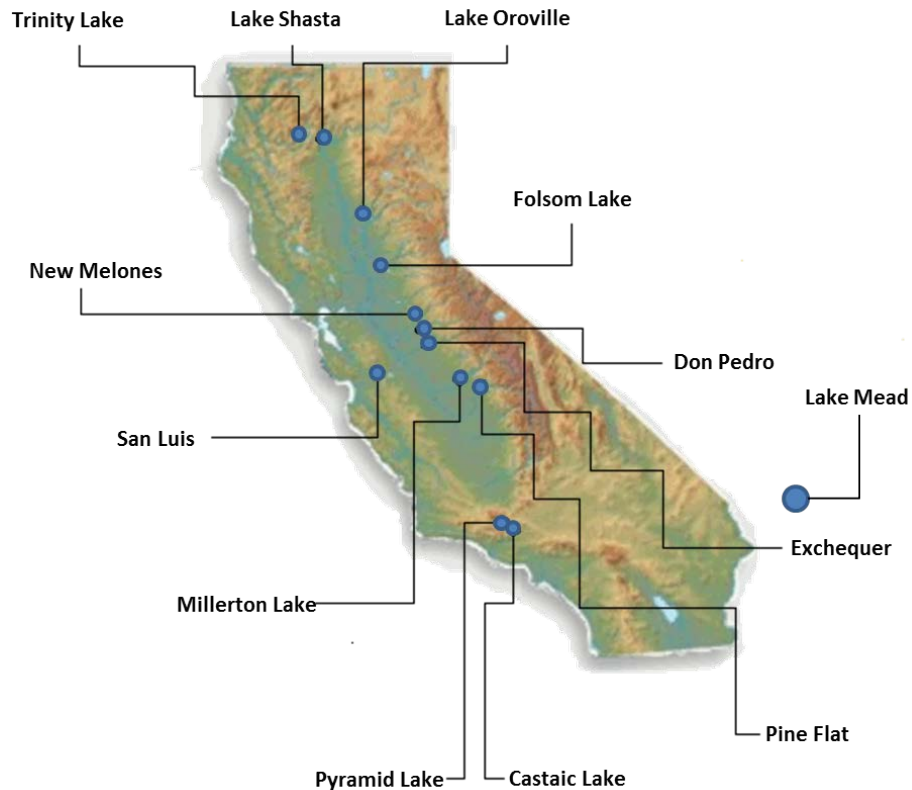


Figure 114 - Location of Major Surface Reservoirs in Model [148]

The Lake Mead reservoir serves Arizona and Nevada in addition to California, therefore not all of its capacity can be treated as a California reservoir. The allocations of water from this reservoir are governed by the Colorado River compact [191], and are fixed by contract.

Therefore, to include Lake Mead in the model, an effective reservoir representing the portion of Lake Mead that serves California is created by scaling down the reservoir capacity of the Lake Mead reservoir according to the allocation distribution in the Colorado River compact.

Each reservoir is tasked with primarily serving the water needs of a given hydrologic region.

Water conservation or production measures that are implemented in a given region will directly displace demand on the reservoirs serving it. In addition, the included reservoirs are linked either by natural river flows or by artificial canals, and this structure forms the basis for how changes in

the demand on one reservoir affect demands on other reservoirs. Therefore, a unit volume of water saved in an area served by one reservoir also affects the demands on all of the reservoirs that supply it. A simplified schematic of how these major surface reservoirs are linked in the model and the location of hydrologic regions are presented in Figure 115 [192]. A table of the assumptions for the demand region directly served by each reservoir is presented in Table 42. The designation of directly-served demand regions are based on the location of the reservoirs and their main river outflows. The designation of reservoir linkages is based on the river topography of the state and constructed major canals, which is tied together by the Sacramento Delta [193]. The connections of major reservoirs to the Delta are also presented in Table 42.

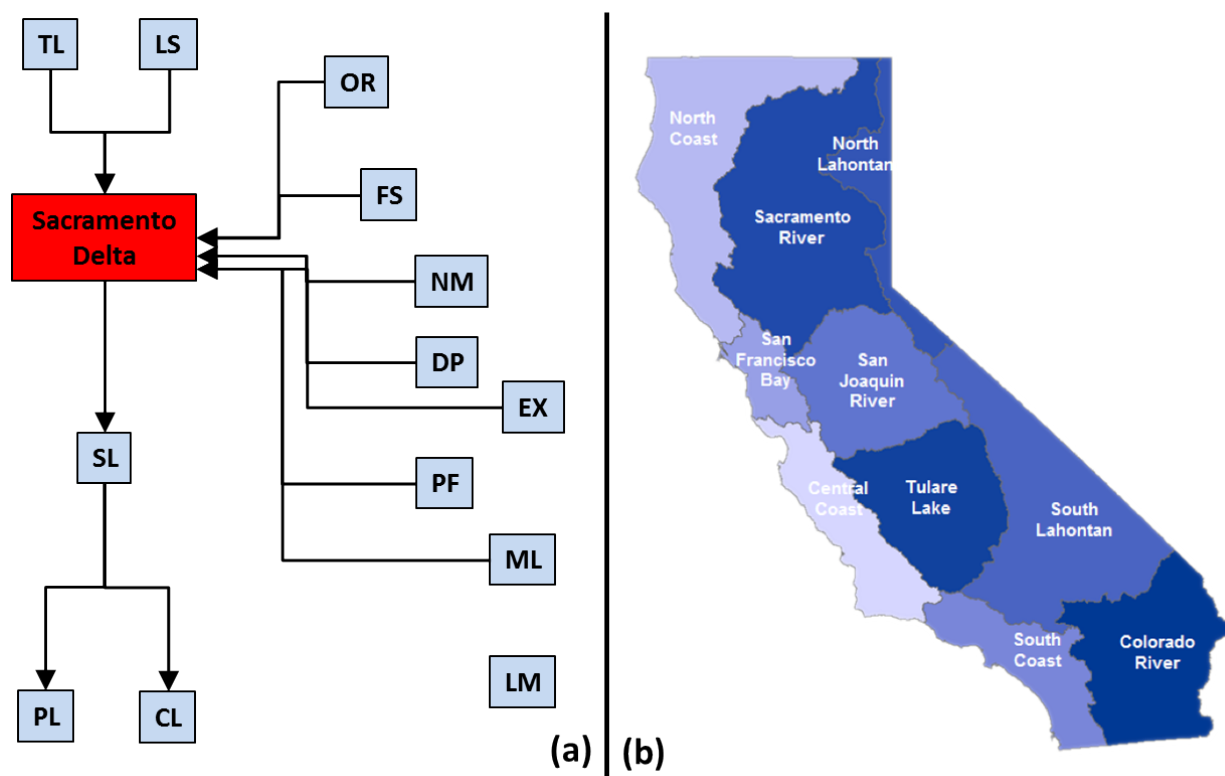


Figure 115 - (a) Reservoir Connections in California. (b) Hydrologic regions in California

It is important to highlight, however, that this model is not a water management model such as those represented by the CalFed [194] or CALVIN [195] models. These aforementioned models

are aimed at examining different water management paradigms for watershed management, flood control, and water allocation policies. This model does not attempt to capture changes in the paradigm of water transfers in the state, other than allowing the presence of water savings due to water stabilization options to free up allocations in the reservoir chain. Otherwise, historical management practices and groundwater demand are embedded in the baseline case of the model.

Inflow data for each of the reservoirs was obtained from the California Data Exchange Center [196], State Water Project operation reports [43], and USGS data [197], for the time period of 2000-2010 with a daily temporal resolution. The demand vector on each reservoir was scaled based on the profile of the outflow data, and model parameters for each reservoir were tuned to resemble historical reservoir operation. Overall, while the mean fill level error for some individual reservoirs vary between 2% and 20%, the statewide aggregate fill condition matches quite well with an error of only 3.884%.

4.3.3. Characterization of Water Stabilization Measures

This model considers five different individual measures for stabilizing water reservoir levels in California: Urban water conservation, water reuse, thermal desalination with waste heat, thermal desalination with direct natural gas, and membrane desalination. The manner in which these options are characterized in terms of their potential and integration into the model is described here.

4.3.3.1. Urban Water Conservation (UC)

The potential for urban water conservation used in this study is taken from an analysis conducted by the Pacific Institute [110], which examined the potential for conservation in different regions in California. The nature of water conservation measures consists of the following:

- Improvements to water use of indoor appliances such as toilets, sinks, showers, etc... by the installation of low-flow appliances in residential sectors
- Water savings from reducing losses and inefficiencies in the water distribution system such as leakages and providing adequate maintenance
- Efficient hardware and management improvements for outdoor urban water use. This primarily consists of reducing water usage for watering lawns, gardens, and other landscaping items
- Reductions in the water usage in various commercial and industrial processes such as manufacturing of products.

With all of these measures combined, the authors concluded that the minimum cost effective urban water conservation potential statewide is about **2.02 million acre-feet per year or 6.824 Mm³/d**. This figure was set as the 100% potential mark for this study, and spanning cases are carried out up to this limit. The water savings or reduction in demand is distributed spatially across the hydrologic regions according to population [48]. Temporally, the water savings are assumed to follow the profile of the reservoir demands that are serving the corresponding region.

Urban water conservation does not involve any direct processes that use electricity. This option simply involves the reduction of the raw urban water demand due to the installation of low flow hardware and reduction of leaks. The primary effect of this option is to reduce the amount of water that must undergo the infrastructure processes outlined previously and associated energy consumption.

This particular option affects all components of the water supply infrastructure. Water that is conserved is water that does not need to be conveyed, treated, distributed, and subject to

wastewater treatment. The temporal profile of the reduction in infrastructure loads is based on a study of the hourly behavior of urban water demand components by Funk [198] in California, taking into account indoor and outdoor usage profiles.

4.3.3.2. Water Reuse (PR)

The potential for water reuse was calculated by using appropriate wastewater treatment capacity in the state and current reuse efforts to set a limit on the additional capacity for water reuse. This is calculated as follows.

A list of all of the wastewater treatment plants in California was obtained from the State Water Resources Control Board Regulated Facilities database [199]. This database contains the maximum capacities of each plant, its location, and the thoroughness of its treatment levels. For water reuse, the effluent from a wastewater treatment plant must be fairly contaminant-free before discharging back into the environment, therefore only plants with the highest complexity treatment designation (“A”) were included. These plants include primary and secondary stage wastewater treatment processes. The locations of the plants were used to distribute this capacity by hydrologic region.

It is important, however, to account for reuse efforts that are already in operation. To obtain this capacity, data for California for the year 2009 was obtained from the National Water Reuse Database [136]. This database contains all of the wastewater treatment plants that are engaged in reuse efforts, including their location. For each hydrologic region, the corresponding capacity was subtracted from the wastewater treatment capacity to obtain the potential for water reuse.

With these datasets, the statewide theoretical capacity for water reuse is calculated to be **18.4 Mm³/d**. This is set as the 100% potential mark for this option. Additionally, the temporal profile of this option is assumed to follow the water demand.

This study considers three processes for the reuse of wastewater treatment plant effluent: Microfiltration (MF), Reverse Osmosis (RO), and Ultraviolet/Hydrogen Peroxide (UV/H₂O₂) advanced oxidation process. These processes are used for treating wastewater to be reused via indirect potable reuse.

The energy footprint of these processes has been studied in depth by Sobhani [111], for a water reuse plant with indirect potable application that is currently operating in Pacific Coast area.

The energy intensities of these individual processes which are utilized in this study are presented in Table 43. The hourly profile of these loads is tied to the temporal profile in wastewater treatment plant influent flow. All three processes follow this same profile, which is also presented by Sobhani [111].

Table 43- Energy Intensity of Water Reuse Processes

<u>Process</u>	<u>Average Energy Intensity [kWh/MG]</u>
Microfiltration	845
Reverse Osmosis	2025
UV/ H ₂ O ₂ AOP	302

Water reuse also affects the infrastructure loads primarily by displacing the conveyance component. Using recycled water to meet local demands reduces the amount of water that must be pumped into the region through the conveyance system, provided that coordination between local and central water management authorities takes place. Depending on region, however,

additional pumping may be required to transport water from the reuse plant to local-use reservoirs. This option also does not displace any of the other infrastructure component loads. Treatment must still take place since this model assumes indirect potable reuse; water supplied by this measure must still be distributed to end users and treated in wastewater treatment plants.

4.3.3.3. Thermal Desalination with Waste Heat (TDw)

The potential for thermal desalination with waste heat was determined by calculating the waste heat potential from power plants located on the California coast, and using a first principles plant model to determine the specific heat consumption of a representative thermal desalination plant.

The waste heat potential was calculated by data from eGRID 2013 [200]. This database includes all of the power plants in California, its annual generation, and its heat rate on a lower heating value (LHV) basis. The waste heat potential for the Diablo Canyon nuclear power plant, which does not have an LHV heat rate, was calculated from the annual electric generation assuming an efficiency of 30%. This figure is typical of conventional steam turbine cycle power plants. From these parameters, the available waste heat energy can be calculated. Power plants located on the coast were selected and sorted into three hydrologic regions: South Coast, Central Coast, and North Coast, to spatially distribute waste heat potential.

The waste heat potential was converted to a capacity potential by use of a model for a Multi-Effect Evaporation (MEE) power plant constructed by Ettouney [107]. The MEE system was chosen due to its ability to use low temperature waste heat and reduced seawater withdrawals compared to multi-stage flash systems. A representative plant size of 40000 m³/d with 12 effects and a heating steam temperature of 60° C, desalinating seawater with default settings (36 ppt salinity) were used in the computation. The specific heat consumption per cubic meter of water

desalinated was calculated by taking the enthalpy difference between the heating steam and the condensate reject from the 1st effect. From these parameters, the waste heat potential was converted to a plant capacity potential.

These datasets set the capacity for thermal desalination with waste heat at **3.632 Mm³/d**. The operating profile of this option is assumed to be steady, which is similar to other desalination plants currently deployed in the world [201].

To capture the energy consumption of thermal desalination plants, a detailed, first-principles model of a Multi-Effect Evaporation thermal desalination plant developed by Ettouney [107] is used. This type of thermal desalination plant operates by evaporating intake water in a series of decreasing pressure vessels known as effects, by spraying feed seawater on a series of tubes that are heated by hot steam. Details of this plant type can be found in the literature. The use of an MEE configuration was selected for its ability to use relatively low temperature heating steam to drive its processes.

The utilized model is a first principles-based heat transfer and thermodynamic model. Primary inputs for the plant design involve the plant capacity, number of effects, heating steam and reject brine temperature and salinity (of each effect), and dimensions and heat transfer parameters for plant components. Inputs for inlet water conditions include intake seawater temperature, and salinity. For this study, the major input parameter settings used are presented in Table 44. The number of effects and heating steam temperature was chosen to maximize the performance ratio of the plant within practical limits of pressure management and preventing scaling in plant components.

Table 44 - Input Parameter Values for MEE Plant Model

<u>Input Parameter</u>	<u>Value</u>
Number of Effects	12
Single Plant Capacity	40000 m ³ /d
Heating Steam Temperature	60° C
Intake Seawater Temperature	25° C
Intake Seawater Salinity	36000 ppm

Using this model, the electric energy and thermal energy consumption can be calculated. The electric energy consumption of thermal desalination plants is primarily based on internal plant pumping loads, which are an output of the model. The thermal energy consumption is calculated from the difference in enthalpies of the heating steam entering the first effect and that of the condensate reject from this first effect, both of which can be calculated from temperatures and pressures in the model as follows:

$$\dot{Q} = \dot{m}_{HS} * \left(h_{HS}(T, P) - h_{CR,E1}(T, P) \right)$$

Using these parameters, the specific electric and thermal energy consumption of this plant type are calculated and presented in Table 45.

Table 45 - Specific Electric and Thermal Energy Consumption of the representative MEE Plant

<u>Energy Type</u>	<u>Specific Consumption Rate [kWh/m³]</u>
Electric	2.67
Thermal	67.14

The thermal energy supply is provided either by waste heat or by natural gas. Due to limits on the waste heat potential as calculated from eGRID data for coastal power plants [200], the capacity of the former is limited. The hourly profile of this load is assumed to be steady.

4.3.3.4. Membrane Desalination (MD) and Thermal Desalination with Direct Natural Gas (TD)

These particular options are not characterized by a technical potential, unlike the other options considered in this study. From a technical standpoint, there is not a hard limit on the capacity of these measures, although installing them to extreme capacities has other implications such as energy use, greenhouse gases and brine production. The characteristics of both of these options, however, are also captured using representative plant models by Ettouney. [107].

Thermal desalination with direct natural gas is represented using the same plant model as that for thermal desalination with waste heat, however, the specific heat consumption and installed capacity are converted to a natural gas consumption value assuming an LHV basis. This will be explained in more detail in Part 2 of the study.

Membrane desalination is represented using a plant model of a two-stage reverse osmosis membrane system, with a representative plant capacity of 40000 m³/d, using seawater feed composition (36 ppt salinity) as the input.

Both of these measures are spatially distributed into three regions: South Coast, Central Coast, and North Coast. In this case, the distribution of capacity is free to be specified.

The energy consumption of membrane desalination plants was also calculated by use of a first-principles model of a reverse osmosis plant developed by Ettouney [200]. For this study, a two stage seawater reverse osmosis desalination plant configuration is used due to its relatively low specific energy consumption. Plant design parameters include plant capacity, permeate pressure, feed temperature, and flow/salinity parameters for each element. The major input parameters used as inputs to the model are as follows:

Table 46 - Input Parameter Values for SWRO Plant Model

<u>Input Parameter</u>	<u>Value</u>
Single Plant Capacity	40000 m ³ /d
Permeate Pressure	101 kPa
Feed Temperature	25° C
Intake Seawater Salinity	36000 ppm

All other parameters are set to the model default value for seawater desalination. Using this model, the specific electric energy consumption of a plant with this design is calculated as an output of the model to be about **4.7 kWh/m³** of water produced.

4.3.4. Water Supply Infrastructure Energy Impacts

Supplying water to end users for various uses in different regions across the state involves a number of processes to transport water to demand regions and treat it for use and environmental discharge. All of these processes use energy, and for components such as conveyance, have different energy impacts depending on their spatial distribution. In order to more accurately quantify the energy impact of implementing options to stabilize reservoir levels, the effect of these options on the energy usage of water supply infrastructure components must be captured. To accomplish this, the energy intensity of the operation of these infrastructure components must be factored into the model.

4.3.4.1. Conveyance

The primary water supplies for the state of California are equally distributed on a spatial basis across the state. A majority of the primary water supplies are sourced from precipitation / snowpack and river inflows in the northern and eastern regions of the state. A large portion of the water demand, especially for urban uses, is not located in proximity to these regions. The urban

water demand is heavily biased towards the coastal regions where major cities are located. Therefore, energy must be used to transport water from these supply sources to demand regions. Conveyance to most areas in northern California from supply regions requires very little energy, since it is based on gravity-driven flow through natural rivers. Only a small amount of pumping energy is required for transporting water across flat valley floors in certain regions. Conveyance to southern California, however, requires a relatively large amount of energy. The urban water demand is heavily focused in the South Coast and Colorado River regions, with the former containing 49% of the state's population [48]. Transporting water into this region requires pumping of water over long distances and over the Tehachapi Mountain Range, which poses a significant elevation barrier.

This study uses average factors for conveyance to meet the demand in each hydrologic region as outlined by the California Energy Commission (CEC) [63] as presented in Table 47. These factors represent the pumping energy usage of major conveyance projects such as the State Water Project. As a reference, the locations of these regions are presented in Figure 116:

Table 47 - Conveyance Energy Intensity for Different Hydrologic Regions used in this study

<u>Group</u>	<u>Hydrologic Regions Included</u>	<u>Energy Intensity</u>
Northern California	North Coast Sacramento River North Lahontan San Francisco Bay San Joaquin River Central Coast Tulare Lake South Lahontan	150 kWh/MG
Southern California	South Coast Colorado River	8900 kWh/MG



Figure 116- Hydrologic Regions in California [192]

4.3.4.2. Treatment

Depending on the intended end use, the extent of treatment required for water supplies may vary.

Agricultural and industrial uses often do not require highly treated water, and the degree of chemical and biological contamination in source water depends on the specific region it is sourced from. Water use for residential and commercial use, however, requires treatment to potable standards, including the removal of harmful microorganisms, chemical compounds, and particulate matter.

Historical methods of water treatment including the use of chemical and mechanical methods do not require a significant amount of energy, however, new methods for treatment such as the use of ultraviolet radiation requires more energy. Depending on end use and source, the energy intensity of water treatment ranges from 0-1600 kWh/MG. This study uses an average factor obtained by the CEC [63] for the energy intensity of the average treatment process of **100 kWh/MG**.

4.3.4.3. Distribution

Once water is conveyed to a major city or town, it must then be distributed to each individual end user. This involves the pumping of water through pipe networks in cities and buildings, which may require a relatively high amount of energy. This study uses a representative factor from the CEC study of **1200 kWh/MG** [63].

4.3.4.4. Wastewater Treatment

Water that is collected post end-use must be treated in order to be safely discharged into the local environment or ocean areas. The extent of treatment required depends on the quality of the waste stream, the standards for discharge into a given area, and the processes used to carry out this treatment (activated sludge process, etc...). Depending on these factors, the energy intensity of

wastewater treatment ranges between 1100-4600 kWh/MG [63]. This study uses the representative value for California of **2500 kWh/MG** [63].

Chapter 5: Evaluation of Sustainability Options in Individual Resource Sectors

This section presents results for the evaluation of sustainability-oriented options in the context of individual resource sectors. Note that the light-duty transportation sector is not included, as such an analysis would be redundant as noted in Section 1.5.

5.1. Electricity Sector

Certain parts of these results have been previously presented with modification in the following publications:

- Samuelson, S., Mueller, F., Eichman, J., **Tarroja, B.** Advanced Power and Energy Program. 2013. *Piloting the Integration and Utilization of Renewables to Achieve a Flexible and Secure Energy Infrastructure*. California Energy Commission. Publication number: CEC-PIR-08-033.

5.1.1. Renewable Resources

5.1.1.2. Literature Review

The unpredictable behavior of variable renewables like solar and wind power renders their integration into the grid challenging since energy and reliability requirements must be simultaneously satisfied. Additionally, the integration of renewable resources will require significant changes in the design and operation of grid balancing resources such as thermal power plants. Therefore, a number of entities have investigated the impacts of renewable generation behavior on the electric grid to different levels of detail. Some of these studies are described as follows.

Milligan and the NREL Western Wind and Solar Integration (NREL-WWSI) [202] project have investigated on the effect of the holistic integration of wind and solar resources on electric grid operations up to renewable penetration levels of 35%. Utilizing modeled wind and solar data, the study discovered that coordination between different balancing areas is necessary to reach a

renewable penetration level of 35% or higher. The aggregation of wind and solar sites was found to aid in mitigating the impacts of large renewable power fluctuations, and the operational impacts of renewable resource integration did not differ significantly between the use of local, low-quality resources and remote, high quality resources. Exports of power from the study footprint area which covers a large portion of the southwestern United States were found to decrease as the renewable penetration of the receiving area increased.

Ostergaard [203] presented use of a multi-criteria optimization analysis for demonstrating the sensitivity of energy system design with renewable resources to the prioritization of different optimization criteria using the EnergyPLAN software. Examples of optimization criteria included whether the system operated in non-islanding or islanding mode, reserve capacity requirement, import/export use, fossil fuel use, renewable penetration level, carbon dioxide emissions, and various components of energy-related costs. The analysis was applied to the integration of heat pumps and wind power in Western Denmark using well defined cases as an example, and it was discovered that the prioritization of different optimization criteria yielded very different ‘optimal’ system configurations. In addition, there have been a number of further efforts that have focused on the optimization of the renewable resource mix for different types of systems based on prioritization of certain criteria [204-206]

Lund [207] performed an analysis using the EnergyPLAN software to determine the optimal combinations of solar photovoltaics, wind power, and wave power to be integrated into a Danish power supply with a high degree of combined heat and power penetration. Hourly data for wind, solar, and wave power were obtained for the year 2001 from various sources. The main metric used for evaluation was the amount of excess renewable generation present, and the search for

combinations of the aforementioned resources were conducted to minimize the amount of excess renewable generation present by taking advantage of synergies between the different renewable resources present in Denmark. It was shown that the large scale integration of individual renewable energy resources imposed a large amount of excess power generation. To minimize the amount of excess power generation, it was concluded that wind power should produce 50% of the total energy obtained from the renewable mix, and the complementing combination of solar photovoltaic and wave power is dependent on the total renewable penetration level. If the penetration level is below 20%, the optimal contributions were found to be 40% solar photovoltaic and 10% wave power. If the penetration level is above 80%, the optimal combination was found to be 20% solar photovoltaic and 30% wave power. Further, it was concluded that the mixture of different renewable resources alone would not eliminate the onset of excess power generation, and while it was a supplement to potential solutions, other strategies would need to be utilized to integrate large amounts of renewable resources without excess power generation. Lund [208] also further used the EnergyPLAN model to conduct an energy flow analysis to discuss the issues and perspectives regarding reaching a 100% renewable penetration level in Denmark, focusing on wind, solar, wave, and biomass power. It was concluded that from an energy flow perspective, the attainment of this goal is possible since the necessary renewable energy sources are present and is contingent on the development and implementation of technologies such as combined heat and power, heat pumps, hydrogen storage for frequency regulation and production of fuel for transportation in combination with savings and efficiency improvements.

A report by the California Energy Commission [209] conducted a review of international experience with the integration of variable renewable energy resources onto grid-scale power

systems, focusing on lessons learned that could aid in the integration of renewable energy resources into the California electric grid. This report focused primarily on wind power due to the large installed capacity of wind farms throughout the world compared to solar power. It was discovered that transmission system operators in Europe tended to implement very strict control strategies for the management of wind power, including ramp rate limits, the required ability to provide frequency control, and wind power curtailment strategies. A restructuring of the ancillary service provisions was found to be necessary at higher renewable penetration levels. Issues were also reported in New Zealand regarding the onset of very high ramp rates and curtailment due to the presence of a base load in the power system. A diverse array of strategies including wind forecasting and demand response has been implemented to accommodate wind power, however the specific strategies utilized vary by region and country. It was also suggested by various studies that the implementation of wind turbine performance controls and the sharing of reserves or energy imbalances between multiple control areas allowed more robust management of increasing amounts of variable generation.

Additional integration reports and studies have been conducted focusing explicitly on wind power [210-213]. Wind power has been the focus of many integration studies due to its large grid-tied capacity worldwide and its higher degree of unpredictability. An outline of technical challenges presented by the integration of wind power into the electric power system was presented by Georgilakis [214]. It was discovered that the variable nature of wind power could pose challenges for the dispatch and allocation of reserve resources, using the reserve capacity requirement as the main metric and indicating that for a wind penetration level of 10%, the reserve capacity increase is on the order of 2-10%. The variable nature of wind power also has implications for the costs associated with its integration into the current market structure,

indicating that operating cost impacts are small at low penetration levels and moderate at higher penetration levels (10% or higher). Variation in wind power output also poses issues for the power quality of electricity on the transmission system, causing voltage dips, frequency variations and low power factors, possibly undermining the ability of the electric grid to provide the levels of reliability required by end users. Economic transmission planning has also been deemed a challenge. Finally, the onset of wind power curtailment due to excess power generation without complementary energy management strategies or strong interconnections with other control areas was discovered to be a challenge. Similar types of challenges were also identified by a variety of other wind integration studies [213, 215, 216].

However, there have been some integration studies for large scale solar power. Denholm [217] analyzed the impacts of large scale solar photovoltaic deployment on generators on the electric grid, also primarily using the amount of curtailed renewable energy as the main metric for quantification. It was concluded that due to the large reliance of the current generator fleet on base-loaded generators, large amounts of electricity generated by solar power would have to be rejected by the electric power system when the solar penetration level reaches about 15%. To accommodate the large scale deployment of solar photovoltaics, it was concluded that an increased degree of generator flexibility brought about by decreased reliance on base-loaded generators could allow solar penetration levels to reach 20-30% before the onset of curtailment for solar power. The use of energy management strategies such as energy storage, demand response controls of end use appliances or linkage with the transportation sector in terms of plug-in hybrids or hydrogen production could be used to allow the solar penetration level to be increased further.

The California Independent System Operator (CAISO), which is burdened with actually integrating these resources, has also produced studies regarding the integration of renewable resources into California's electric grid. This includes two Integration of Renewable Resources reports, one by Loutan and Hawkins [218] and the other by GE Energy Consulting [78]), and an in-house study which examined the effect of increasing variable renewable power on the required ramp rates of balancing generators for the particular renewable penetration levels of 12%, 20%, and 33% [160]. This analysis found that the load-following fleet ramp rate up and down capability needed to be increased slightly from the 12% to the 20% renewable penetration level, but needed to be significantly increased from the 20% to the 33% renewable penetration level. This implies an exponential increase pattern with renewable penetration level. Similar reports have also been published by the California Energy Commission (CEC), including a report from KEMA, and the Intermittency Analysis Project [143, 219], as well as for the entire United States and groups like the International Panel on Climate Change (IPCC) that have prepared a review of renewable technologies and the implications for their integration into grid systems [220].

An examination of the costs and wear on balancing generators associated with increased variable renewable generation was investigated by Kumar [46]. This study found that with current technologies, increased ramp rates and number of start-up events can cause damage to power plant equipment and shorten power plant component lifetimes. Aging power plants that were designed around base load operation were most vulnerable to damage.

Effects on the composition of the balancing power plant fleet have also been examined. A study by Tarroja [221] also found that the capacity percentage of non-renewable generator capacity that operates for longer than 1 week was found to drop significantly with increased renewable

penetration level. Additionally, a study for the Southwest Power Pool projected that even at present wind penetration levels in their respective region, approximately one-third to one-half of base-load coal plants will not be needed to provide power during minimum net load hours [222].

Effects of increasing the renewable penetration level on the electric grid on the levelized cost of electricity have also been examined in the absence of complementary technologies. Eichman [148] found that increased variable renewable penetration increases the levelized cost of electricity linearly at first, and then exponentially as renewable curtailment becomes excessive. This behavior included cost factors such as renewable installation costs, shifting in fuel mix and degradation due to increased operational flexibility with current technologies.

Many of these studies have focused on assessing different aspects regarding the impact of integrating renewable resources onto the electric grid. This study follows up on this research by comparing the advantages and disadvantages of different renewable resources in the context of the identified impacts on grid resource design and operation.

5.1.1.3. Approach

5.1.1.3.1. Spanning Scenarios

With the capabilities of the STREET model, the development of spanning cases to compare and contrast the effects of different renewable resource types is straightforward. This particular study focuses on spanning the installed capacities of five different renewable types:

- Fixed Rooftop Solar PV
 - This refers to solar PV installations sited in population centers, on top of existing rooftops.
- 1-axis Tracking, Utility-scale Solar PV

- This refers to solar PV farms installed in the desert resource areas of the state with azimuth tracking.
- 2-axis Tracking, Utility-scale Solar PV
 - This refers to solar PV farms installed in the desert resource areas of the state with both tilt and azimuth tracking.
- Local (Distributed) Wind Turbines
 - This refers to wind turbines sited near population centers in the state, with appropriate wind speed profiles.
- Regional (Centralized) Wind Turbines
 - This refers to wind turbines sited away from population centers but in high resource areas, particularly in the southeastern region of the state.

This section focuses on variable renewable power. Therefore, capacities of small hydropower, biogas/biomass, and geothermal power are not spanned in this particular analysis. This approach is taken since the potential contributions of the non-variable renewable types are limited, and these limits have been well characterized. The current understanding of the limits on the contribution of non-variable renewable types was described in Section 4. Additionally, non-variable renewable resources do not necessarily have strong impacts on the design and operation of grid resources, since these renewable types can either be dispatched at will or their behavior is relatively predictable. This section not only seeks to examine the contribution of renewable resources towards aggregate emissions performance, but also towards shifts in the operation of grid balancing resources, the focus is on variable renewable types.

Each spanning scenario starts at a renewable penetration level of 8.95%, representing the non-variable renewable contribution to the load demand in the year 2005. For each of the variable renewable types mentioned previously, the capacity is incrementally increased from zero to 300 GW. Additionally, a hybrid case which uses a 50% regional wind, 50% 1-axis tracking solar PV mix is used to demonstrate the effects of diversifying the renewable portfolio. The capacities of base load power plant capacities such as coal, nuclear, and geothermal are constant and set to the levels present in the base year of 2005.

5.1.1.3.2. Metrics

The following metrics are considered to characterize the effect of renewable resources on the design and operation of the system:

Installed Renewable Capacity: This refers to the required amount of renewable resources to be installed to reach a given renewable penetration level. A lower installed renewable capacity to meet the same renewable penetration level is preferable, since less investment would be required to meet renewable energy targets.

Capacity Factor: This is defined as the ratio of the energy obtained from all generators on the grid (including renewables) to the amount of energy that would have been obtained if all of those generators operated at rated capacity for the entire year. This metric represents the utilization of resources on the electric grid. Higher capacity factors are preferable, since this represents a better return on investment for the resources on the grid.

CO₂ Emissions: This refers to the total annual emissions of CO₂ from the electric grid. Lower emissions are preferable to mitigate climate change impacts.

Average Balance Fleet Ramp Rate: This refers to the amount of power that the load-following and peaking generator fleet will be required to change in one hour in order to meet the load demand. The ramp rate effects are separated into up (increasing power) and down (decreasing power) categories. This metric has implications for the required capabilities of balancing generators such as gas turbine power plants to be able to support variable renewable integration in the future.

Average Balance Fleet Starts: This refers to the average number of start-up events per year for a typical load following or peaking power plant. Starts increase wear and accelerate degradation of power plant equipment and create additional criteria pollutant emissions. A lower number of starts are preferable.

Levelized Cost of Electricity (LCOE): This represents the cost of a unit of electric energy delivered to a load center, taking into account the capacity and operation of all generation and complementary technologies in the system. Lower LCOE values are preferable.

5.1.1.4. Results

5.1.1.4.1. Behavior of the Installed Renewable Capacity

For each of the renewable resource types considered, the required installed capacity to reach a given renewable penetration level under the assumptions of this particular study is presented in Figure 117. The renewable penetration level is the fraction of the electric load demand actually served by renewable resources. It is important to note that the renewable penetration numbers shown here are relatively small compared to RPS goals. This is an artifact of the high base load capacity levels assumed for this particular analysis which gives rise to a high minimum generation level and the reliance on a single renewable type for each of the cases. However, the trends are representative between the renewable types.

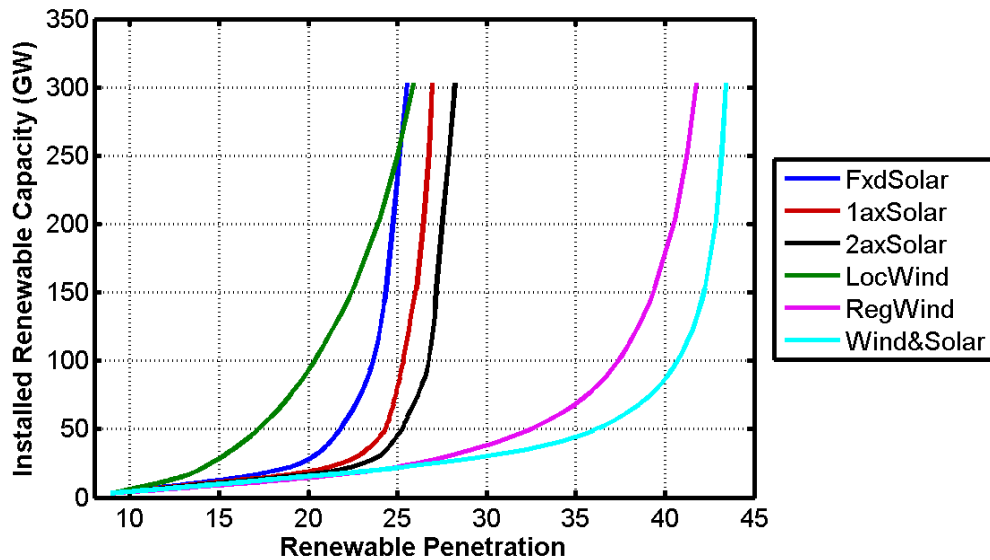


Figure 117 - Renewable Penetration vs. Installed Capacity for Variable Renewable Types

For each of the renewable types, two distinct types of behavior are present regarding the effect on the required installed renewable capacity.

The first type is characterized by a relatively linear increase in required capacity with renewable penetration level, which tends to occur at low capacities. On the electric grid, there exists a minimum amount of generation that cannot turn down in power output or shut down in response to renewable generation. This generation consists of base load power plants such as coal or nuclear powered Rankine-cycle installations which physically cannot respond on short timescales, and flexible power plants such as natural-gas powered load follower installations which must remain online to provide reliability services to the grid. At low renewable capacities, the peak power generation of the different renewable types is relatively low and not large enough to cause the net load demand to drop below the minimum generation level and require curtailment of renewable generation. The relationship between renewable capacity and the corresponding energy contribution to the load demand is one-to-one in this region. Therefore,

every MWh of energy obtained from a given capacity of installed renewable resources is available to serve the load demand. Increasing the renewable capacity with this behavior therefore increases the energy contribution to the load demand, and therefore the renewable penetration level at a constant rate.

The second type is characterized by an exponential increase in the installed renewable capacity required to reach a given renewable penetration level. This occurs due to high renewable generation causing the net load demand to drop below the minimum generation level on the grid, necessitating the curtailment of renewable generation during certain hours out of the year. Therefore, a given increase in the installed renewable capacity does not equate to a fixed increase in the energy contribution to the load demand, since some of the renewable generation is curtailed. This curtailment occurs during times of high renewable generation. Therefore, increases in the energy contribution of the renewable resources to the load demand must be sourced from off-peak renewable generation, which contributes at a lower amount per unit of installed capacity. As capacity is scaled up, slightly off-peak renewable generation starts giving rise to curtailment, and increased contributions will need to be obtained from periods of even lower renewable generation. The continuation of this trend causes significantly more renewable capacity to be installed to incrementally increase the renewable penetration level. For certain renewable types such as all solar PV types, this can impose a hard limit on the energy contribution to the load demand from these resource types. For these resources, a point in installed capacity can be reached when all hours of solar power generation will cause curtailment, but no generation takes place outside of those hours. This necessitates the use of complementary technologies to shift this generation to be available to contribute to the load

demand. An example of the onset of curtailment for the regional wind case is presented for three different renewable penetration levels in Figure 118:

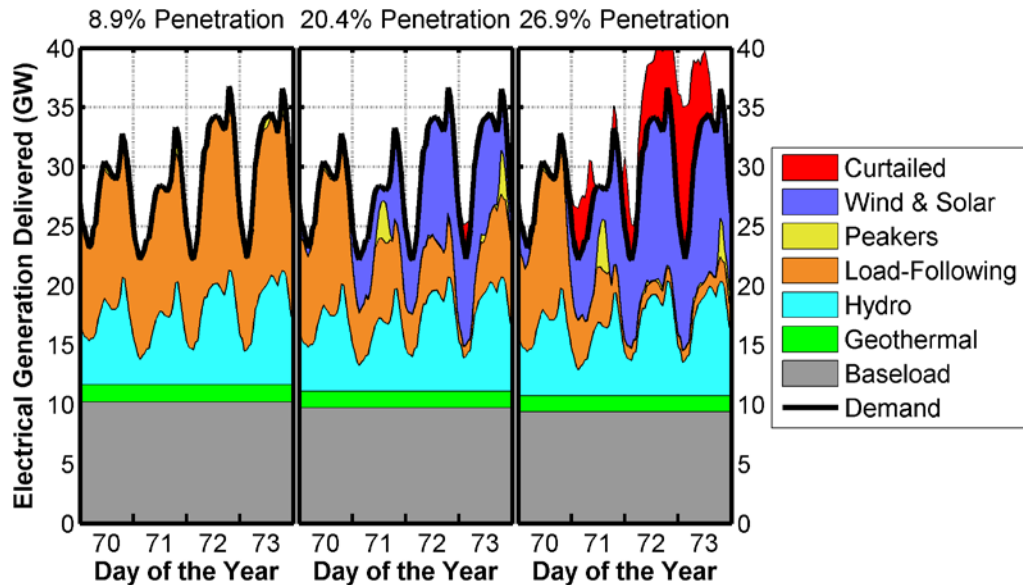


Figure 118 - Onset of Curtailment for Regional Wind

The different renewable types transition from linear to exponential behavior at different renewable penetration levels. This occurs due to the differences in the generation profiles of each of the renewable types. Solar-powered technologies tend to exhibit a more peak-dominated generation profile, where the energy provided by these resources is concentrated in high power, short duration bursts. The characteristics of wind-powered technologies vary by region. In California, wind power near local population centers is very peak-dominated, but wind power and in centralized high resource areas in the state tends to be relatively steady. It is important to note that the actual generation profile for each type varies from day to day and season to season in the simulation.

Local wind requires the most installed capacity to reach a given renewable penetration level. This occurs due to the very low capacity factor of localized wind resources due to low wind

speeds, where actual generation is very small per unit of installed capacity. When combined with peak-dominated behavior, this technology transitions to exponential behavior first.

Fixed rooftop solar PV is the next technology to transition to exponential behavior, followed by 1-axis tracking and 2-axis tracking PV. The peak-dominated behavior of solar power generation contributes to this effect, however, the breadth of the generation profile for solar PV is broader than that for local wind on average each day. Fixed rooftop solar PV also has the lowest capacity factor of the set of solar technologies considered, since it cannot extend the duration of its diurnal generation profile by tracking the sun. The 1-axis tracking and 2-axis tracking PV installations reach exponential behavior at a slightly later renewable penetration level due to this effect. All three technologies, however, reach essentially a hard limit on the renewable penetration level that can be reached by deploying these technologies in isolation due to the effect described previously.

Regional wind transitions to exponential behavior at a much later renewable penetration level compared to all of the other individual technologies. This occurs since the generation profile of regional wind resources in California is very steady compared to the other technologies, and exhibit good resource potentials with capacity factors of 30-45%. This is in comparison to the solar PV technologies, which exhibit capacity factors of 18-25%, and local wind resources which are on the order of 8-10%. High capacity factors indicate a higher energy contribution to the load demand per unit of installed capacity. Steadiness in the generation profile allows the onset of curtailment to happen at a higher renewable penetration level.

Overall, however, it is the hybrid wind and solar case that transitions to exponential behavior at the highest renewable penetration level, requiring lower total installed capacities than any of the

individual renewable technologies. This occurs since wind and solar generation in this region are complementary in that their peak generation typically occurs for one type at times when that for the other type is low. This contributes to a steadier combined renewable generation profile, and showcases the benefits of diversifying the renewable portfolio.

5.1.1.4.2. Behavior of the Aggregate Grid Capacity Factor

The progression of the capacity factor for the entire electric grid due to the installation of individual renewable resource types is presented in Figure 119:

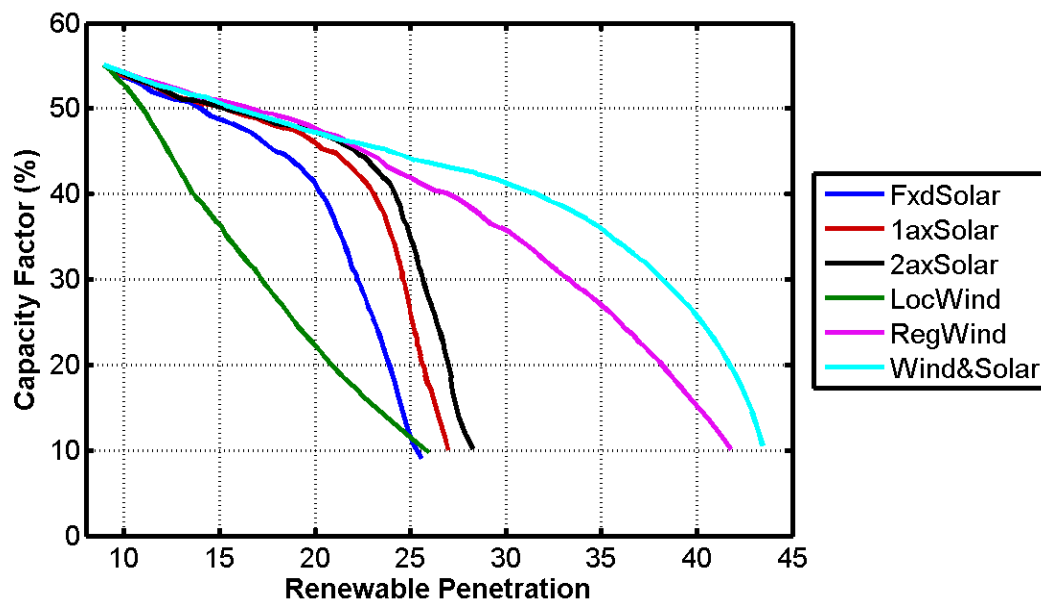


Figure 119 - Grid Capacity Factor vs. Renewable Penetration for Different Renewable Types

For all of the renewable resource types, the capacity factor of the grid decrease with renewable penetration level. This effect is expected since variable renewable resource types exhibit lower generation capacity factors compared to load following and base load power plants, which typically operate with capacity factors of between 40-60% and 65-85%, respectively. Therefore, as resources with lower capacity factors start to contribute a larger share of energy towards meeting the load demand, the grid capacity factor will decrease. At the 8.95% renewable

penetration level, which does not include any variable renewable resources, the grid capacity factor for the combined system is about 55%, including load following, peaking, base load, and hydropower installations.

The progression of the grid capacity factor for each type shows two regions: linear and exponential, same as that for the required installed capacity and caused by the same factors. The individual renewable types with the highest capacity factors and steadier generation profiles impose smaller decreases in the grid capacity factor. The combined wind and solar mix maintaining the highest capacity factors across all renewable penetration levels due to the complementary generation behavior of solar and wind resources in California. This also shows the benefit of diversifying the renewable resource portfolio.

5.1.1.4.3. Behavior of the CO₂ Emissions

The progression of the annual carbon dioxide emissions from the grid due to the deployment of individual renewable types, as a function of renewable penetration level, is presented in Figure 120. This metric is presented as a change in emissions from the base value in 2005.

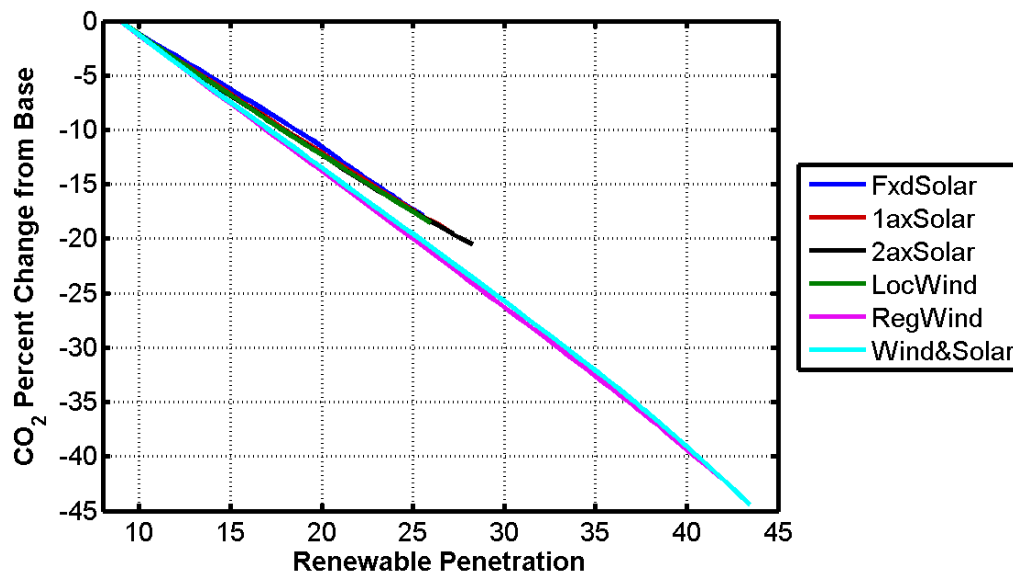


Figure 120 - Annual CO₂ Emissions Change vs. Renewable Penetration for Different Renewable Types

In general, the annual grid CO₂ emissions decrease linearly with renewable penetration level for all of the types. This is expected, since renewable penetration level represents a given energy fraction of renewable, and in this case zero-carbon, generation towards serving the load demand. Displacing energy contributions from fossil-fuel based power plants displaces a given amount of fuel usage and therefore carbon emissions for a particular fossil-fuel resource mix. Therefore, the carbon emissions can be expected to decrease linearly with renewable penetration level.

The differences between the individual renewable types in carbon emission depend on how the generation profile of each type causes the balancing generators to respond. Certain renewables are characterized by quick changes in power output over short periods of time. To respond to this behavior and keep the load demand satisfied, the balancing generator fleet must vary its power output on the same timescale, operate at lower part-load conditions, or in severe cases, shut down and start up. Power plants in the balancing generator fleet are based on thermal cycles, and exhibit lower efficiencies when operating below their rated power output. Power plant start-up

events also have associated emissions which do not contribute towards power generation.

Finally, peaking power plants, which are tasked with responding to the fast variations in the load demand, are based on simple-cycle gas turbine configurations. These units are generally less efficient than their load-following counterparts which are based on combined cycle configurations. Responding to a peak-dominated renewable generation profile triggers all of these characteristics. Therefore, the isolated use of peak-dominated renewable types such as solar power (all types) and local wind does not reduce carbon emissions as much as the use of renewable types or portfolio mixes with more steady aggregate generation profiles for a fixed energy contribution to the load demand. This is evidenced by the regional wind and hybrid wind/solar cases showing increased carbon emissions reductions compared to the local wind and all solar-powered cases. Overall, this highlights the importance in accounting for grid operation details when evaluating aggregate emissions performance.

5.1.1.4.4. Behavior of the Average Balance Fleet Ramp Rates

The progressions of the average balance fleet ramp up and ramp down rates for each of the renewable types as a function of renewable penetration level are presented in Figure 121 and Figure 122:

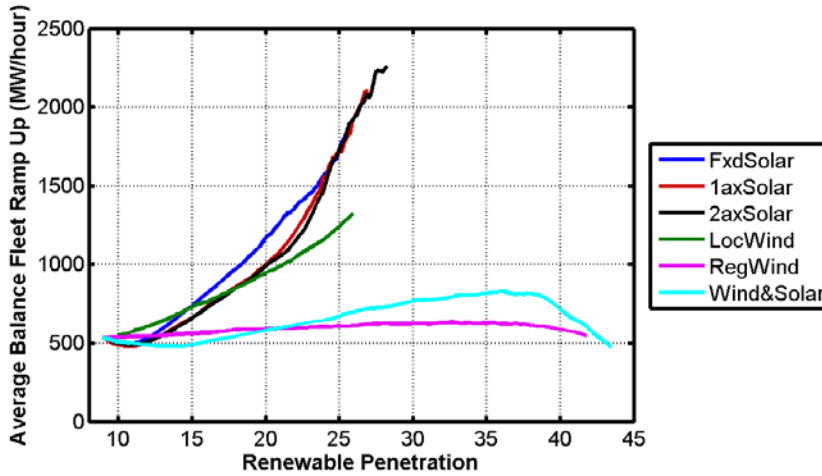


Figure 121 - Average Balance Fleet Ramp Up vs. Renewable Penetration for the Different Renewable Types

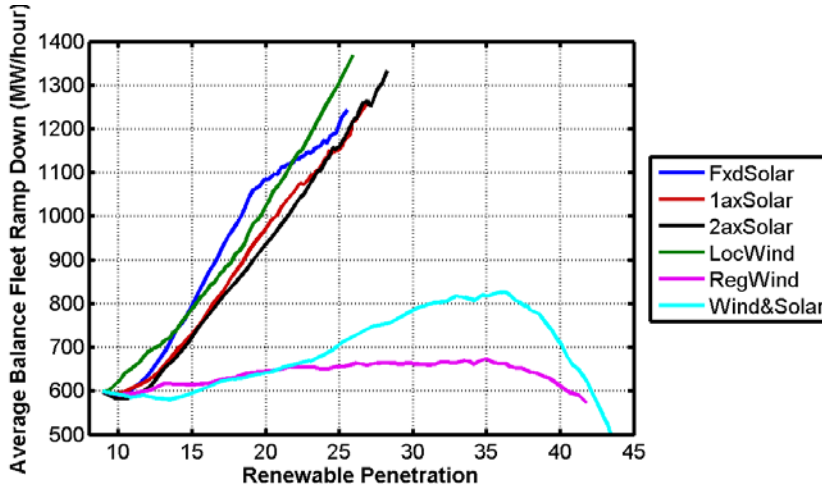


Figure 122 - Average Balance Fleet Ramp Down vs. Renewable Penetration for the Different Renewable Types

For the peak-dominated renewable types, the magnitudes of the balance fleet ramp rates (both up and down) are increased with renewable deployment. This occurs due to the effect described in the results for the carbon emissions, where the balancing generator fleet must respond to high ramp rates in renewable generation with inverse but equally large ramp rates in power plant output to keep the load demand satisfied. Differences between different peak-dominated renewable types are based on the particular weather patterns that give rise to their generation

profile. In this respect, the behavior for the different types regarding ramp up rates are similar to that for ramp down rates, since the ramp up and ramp down rates for renewable resources are generally similar in magnitude. For solar power in particular, however, small decreases in the balance fleet ramp rates occur for small solar power capacity installations, after which the ramp rates increase. This small decrease occurs since the solar power peak is aligned with the load demand peak, but is not as broad in time duration. Therefore, a small amount of solar power will decrease the peak of the net load demand. As solar power increases, however, the peak of the net load demand is shifted to times of the day when solar power generation is not significant. At the same time, however, the periods of peak solar generation are causing decreases in the minimum of the net load demand, increasing the range across which balancing generators must vary their power output. This causes increases in the balance generator fleet ramp rates. This trend has been explored by Tarroja [223].

For the regional wind case, the ramp rates increase slightly, but remain relatively constant with renewable penetration level afterwards. This occurs due to the steadiness of the regional wind power profile. The small increase in ramp rates due to regional wind occurs due to the fact that peak generation for this resource type occurs during the nighttime hours when the raw load demand is low. This decreases the minimum net load demand and therefore increases the range across which the balancing generator fleet must vary its power output. Since the timescale of power variability is relatively long, on the order of hours, the increase in the ramp rates are relatively small compared to that for the other renewable resources.

For the combined wind and solar case, the ramp rates increase up to a certain point in terms of renewable penetration level, but decrease afterwards. This increase is due to the effects of

balance generator fleet response to solar power, however, since capacity levels are smaller, the increase in the ramp rates are not as significant. Additionally, the presence of wind generation contributes to smoothing of the renewable generation profile, which decreases the aggregate ramp rate of the renewable resources and the corresponding ramp rates of the responding balancing generators compared to the peak-dominated renewable resource types. The decrease in ramp rates at high renewable penetration levels occurs since with a combination of wind and solar power generation, renewable generation is typically present to some extent at all hours of the day. At high installed capacities, the net load demand will be at its minimum during many hours and for long periods of time since renewable generation will be large. Therefore, balancing generator fleet may not need to typically respond to variations in renewable power output, since there may be so much renewable generation during certain hours such that variation in this generation profile will still render the net load demand to remain at its minimum.

This result again demonstrates the benefits of diversifying the renewable portfolio since it gives rise to generally better grid resource performance for a fixed energy contribution compared to individual renewable resource types.

5.1.1.4.5. Behavior of the Average Balance Fleet Start-Up Events

The progression of the number of start-up events per generator unit vs. renewable penetration for the combined load-follower and peaker fleet, using different renewable types is presented in Figure 123:

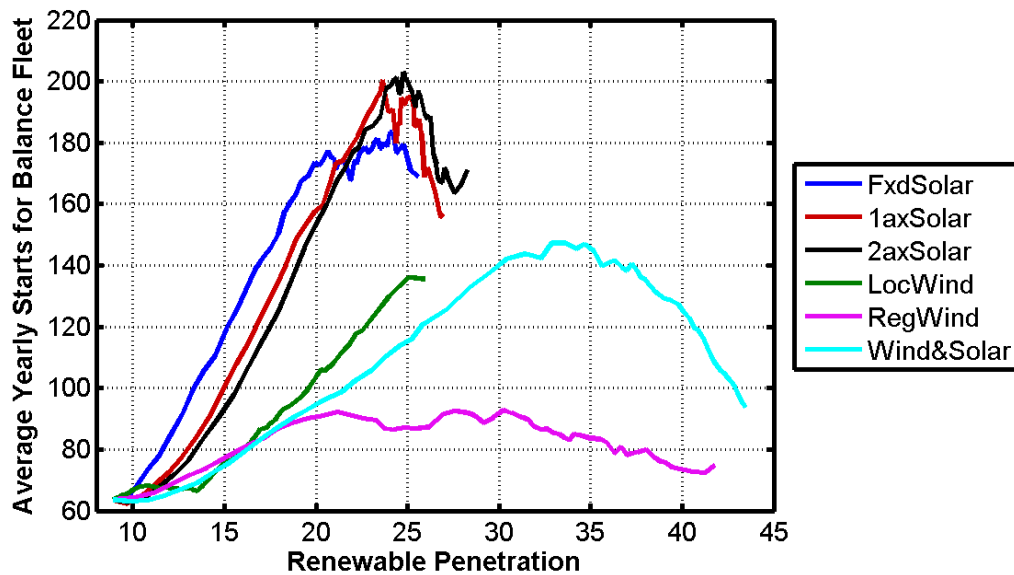


Figure 123 - Average Yearly Start-Up Events per Balance Generator vs. Renewable Penetration for Different Renewable Types

The progression for all of the cases exhibits two distinct behaviors. At lower renewable penetration levels, the average number of balance generator start-up events increases with renewable penetration level. This occurs since the variability of renewable generation increases the corresponding variability of the net load demand, which the balance generator fleet must shut down and start up units to follow. As the variability becomes stronger, the increase in the number of generator start-up events becomes larger. After a certain point, however, the number of generator start-up events reaches a maximum and subsequently decreases as the renewable penetration level increases above that point. This occurs due to the saturation of the generation profile with renewable resources, similar to the effect described for the ramp rate decrease of the hybrid wind and solar case in the previous section. At a certain renewable penetration level, renewable generation is so large that it causes the net load demand which balancing generators must meet to be at its minimum level for long periods of time. Variation in renewable generation during these hours does not cause a response in the behavior of the balancing generator fleet,

rather, it only changes the level of renewable curtailment needed such that the load demand is satisfied. Therefore, certain generators which may have needed to start-up and shut down in response to renewable variability at a slightly lower renewable penetration level are no longer performing this task. The result is for the number of start-up events per balancing generator unit to decrease slightly.

The increase in balancing generator start-up events for the peak-dominated renewable resources is larger compared to that for the regional wind and hybrid wind/solar case. This is expected since the variability that balancing generators must respond to for the peak-dominated renewable resources are larger in magnitude and shorter in timescale. The steady behavior of the regional wind case requires the least increase in the number of start-up events per balancing generator, and therefore exhibits the least amount of generator degradation.

5.1.1.4.6. Behavior of the Levelized Cost of Electricity

The progression of the grid-wide levelized cost of electricity with renewable penetration level when relying on the different renewable types is presented in Figure 124:

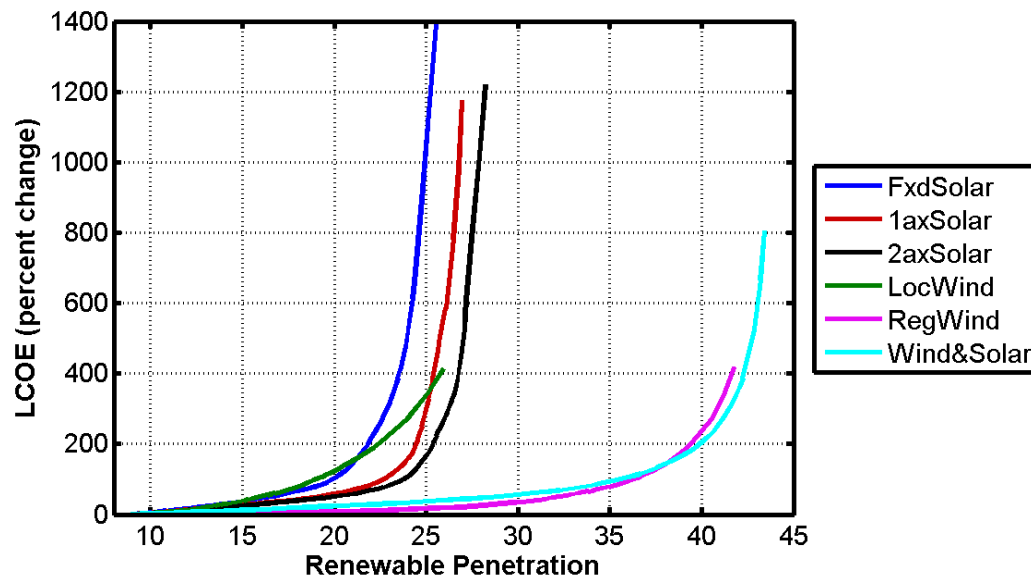


Figure 124 - Percentage Change in the Levelized Cost of Electricity with Renewable Penetration for the Different Renewable Types

The profile of the progression of the levelized cost of electricity with renewable penetration is similar to that for the required installed renewable capacity in that it exhibits two distinct regions: linear and exponential. These two regions occur due to the same factors as that for the required installed renewable capacity. In the linear region, all of the energy produced by the renewable installations are able to be used to serve the load demand. Therefore, the owners of those renewable installations will gain revenue from selling that energy to consumers through the electric markets. This enables renewable installation owners to set the price per unit of energy obtained from their installations at a lower value while still covering their costs, breaking even or making profit. Once renewable curtailment starts to become significant, as discussed in Section 5.1.1.4.1., transition to the exponential behavior occurs. In the exponential region, the installed capacity to provide a given energy contribution to the load demand increases exponentially. Larger capacities require larger capital investments to fund, and incur more costs associated with fixed operation and maintenance as well as other factors. To recoup these costs to break even,

renewable installation owners must set the cost per unit of energy procured from their installations at higher values. Since the capacity increases exponentially, the owner costs increase exponentially, and therefore the levelized cost of electricity increases exponentially.

Despite the result from Section 5.1.1.4.1 that local wind requires more installed capacity compared to fixed rooftop solar PV, the levelized cost of electricity in the local wind case increases at a lower rate than that for solar PV. This occurs since the per-unit capacity capital cost for local wind is significantly cheaper than that for solar PV.

The different solar PV types transition to the exponential region for cost in the same order as that presented in the results for the installed renewable capacity, with fixed rooftop solar PV transitioning first, followed by 1-axis tracking PV, and finally by 2-axis tracking PV. The per unit capacity capital costs of these different PV types are not significantly different, however, the larger capacity factors for the tracking PV types allow the transition to exponential cost increases to be delayed to higher renewable penetration levels.

The regional wind case and the hybrid wind/solar case are able to achieve much higher renewable penetration levels before transitioning to exponential cost increases. This occurs due to the same factors described in the results for the required installed renewable capacity.

5.1.1.5. Summary and Conclusions

5.1.1.5.1. Summary

A spanning study was performed that examined the effects of deploying individual renewable resource types on the electric grid, with respect to greenhouse gas emissions, the design and operation of grid-balancing resources, and the levelized cost of electricity. The advantages and disadvantages of each type were determined and compared with one another to provide a picture

of the preferable deployment of renewable resources in this region. This study is a spanning study. Therefore, real potential limits for the deployment of the individual resources were not imposed, and all resources were deployed to the same capacity. However, this study provides insight into the preferred priority of deployment for the different renewable types in this region based on the characteristics of each type, which can be used to intelligently advise a combined renewable deployment rollout.

5.1.1.5.2. Conclusions

The key conclusions of this study are as follows:

1. Significant benefits for grid performance can be obtained by diversifying the renewable portfolio. The use of the combined wind/solar case required the lowest installed capacity to reach a given renewable penetration level, enabled the highest grid capacity factors, and gave rise to the lowest levelized cost of electricity. In other metrics regarding balancing generator dynamics, it was only outperformed by the regional wind case. In the real system, however, potential limits exist on regional wind deployment. Therefore, an intelligently diversified renewable portfolio will likely be the best configuration for reaching a given renewable penetration level goal.

2. Additional measures must be taken to avoid the onset of renewable curtailment. Due to the variable nature of the renewable resources considered here, curtailment of renewable generation becomes necessary after a certain point in installed renewable capacity. This gives rise to an exponential increase in the required installed renewable capacity and associated costs to increase the renewable penetration level, which is undesirable. Measures to address this could include the installation of complementary technologies such as energy storage or grid-responsive

vehicles, or lowering the minimum load threshold by removing base-load power plant capacity or increasing the part-load capabilities of balancing generators.

3. Regional resources give rise to better grid performance compared to locally-sited resources. For solar power, 1-axis tracking and 2-axis tracking installations outperformed locally-sited rooftop installations due to the sun tracking ability and location in an area with higher incident radiation levels. For wind power, the high resource areas allowed much higher capacity factors due to terrain features that are away from population centers in the state. Even with the costs for transmission included, regional resources still gave rise to lower levelized costs of electricity compared to their local counterparts.

4. Balancing generators will need increased dynamic capabilities to accommodate renewable generation behavior. The variable nature of the renewable types considered here imposed increased ramping and start-up burdens on balancing generators. Technologies for these power plants which enable better load-following performance need to be implemented for the stable integration of renewable resources on the electric grid. The extent of this required performance increase can be minimized by the use of complementary technologies, however.

Overall, not all renewable resources behave similarly. It is important to understand their particular generation characteristics and impacts on electric grid operation in order to intelligently determine the preferred rollout of renewable resources, and the suite and scale of additional measures needed to accommodate them. The latter is the focus of later sections of this dissertation.

5.1.2. Complementary Technologies: Energy Storage

Additionally, sections of this text are described in publications that have been currently

submitted to refereed journals as follows:

- Eichman J.D., **Tarroja, B.**, Schell, L.S., Brown, T., Samuelson, S., “The Effectiveness of Energy Storage Technologies in Supporting Increased Variable Renewable Integration on the Utility Grid”, *Energy*, 2013. **Submitted as of August 2013**

5.1.2.1. Literature Review

The use of energy storage as a complementary technology for supporting the integration of renewable resources has been discussed as a potential solution for supporting various specific aspects of grid integration. A few of the most relevant studies are outlined as follows:

The aggregate scale of energy storage required to restore the capacity factor of the balancing power plant fleet to different levels at increased renewable penetration levels was examined to some extent by Tarroja [221]. Energy storage was applied for net-load profile shaping. Without energy storage and at 2005 renewable penetration levels, the capacity factor of the balancing power plant fleet is roughly 55.8 percent. At the 33 percent renewable penetration level, the combined power capacity of the energy storage fleet must be at least 10 percent of the peak load and must have enough combined energy capacity to sustain that discharge for at least 5 hours. By the 50 percent renewable penetration level, this increases to at least 20 percent of the peak load for power capacity and a rated discharge time of at least 8 hours. Considering the scale of current energy storage systems, these sizes are extremely large even as a combined aggregate. This indicates that for energy storage to perform a net-load shaping function and increase the capacity factor of the balancing power plant fleet, the scale of energy storage required is very large.

Fast-acting energy storage was found to be more effective on a per-MW installed basis at providing regulation services compared to balancing gas turbine power plants. At high renewable penetration levels, the addition of a small amount of storage was able to restore the ACE and maximum frequency deviation to acceptable levels. By contrast, equivalent increases in balancing regulation capacity were not able to restore system performance to the designated targets. In terms of obtaining the same ACE maintenance benefit, a MW of energy storage capacity with a 2 hour rated discharge time was found to be two to three times as effective as a MW of gas-turbine power plant capacity. This would allow the total amount of regulation capacity (energy storage + balancing power plants) to be lower than predicted. KEMA also concluded that using energy storage to provide regulation services has no emissions penalties compared to balancing gas turbine power plants [224].

The use of energy storage for frequency response on the electric power system has also been studied to some extent. GE studied the frequency response characteristics of the California electric power system with increased variable renewable capacities, focusing on wind power. The analysis focused on the use of load-shedding from pumping loads including pumped hydropower storage. With this strategy, the frequency drop after a contingency event was limited to 59.68 Hz compared to 59.4 Hz without load shedding. The study suggested that the same function could be performed with fast-acting energy storage such as batteries and flywheels. Further, the study suggested that a fast-acting energy storage system was worth three times as much as the average balancing power plant in terms of arresting frequency deviations [225].

The effect of implementing storage technologies providing transmission and distribution grid support and renewable integration / time shifting on the cost of electricity delivered to the consumer was examined by EPRI [86]. Compared to a typical combined cycle power plant, the implementation of energy storage was found to increase the cost of electricity to the consumer across all technologies. The energy storage technologies which demonstrated cost levels competitive with balancing power plants were pumped hydropower and compressed air energy storage.

Also, many studies in the literature outline the capabilities and various potential applications of different energy storage types in the context of supporting renewable integration into the electric grid [45, 82, 88, 226-229]. These applications include net-load shaping, provision of spinning reserve capacity, and congestion relief on transmission and distribution systems.

While the performance of energy storage has been examined to some extent, much of these efforts have taken place in small scale or isolated systems [230-232]. There are only a few studies in the literature that examine these applications on the large scale within the context of supporting renewable generation. A notable exception is presented by Kaldellis [233].

Additionally, there has not been much insight into the explicit effect of the use of energy storage on the performance of the grid and the design and operation of load-balancing resources that manage the system within the context of renewable power generation. This study aims to shed some insight into how energy storage affects grid operations and the value of such systems to the grid overall, particularly with increasing contributions from renewable generation.

5.1.2.2. Approach

5.1.2.2.1. Metrics

This analysis is aimed at examining the effectiveness of energy storage in supporting the integration of variable renewable power on the utility grid. The metrics used to characterize this effectiveness are the exact same as those used for the renewable capacity spanning analysis presented in Section 5.1.1. For this study, however, it is important to note that energy storage alters both the profile and magnitude of the total load demand, and therefore can affect the capacity of renewables required to meet a certain fraction of the energy of the load demand.

5.1.2.2.2. Scenarios for Analysis

5.1.2.2.2.1. Renewable Mix

The renewable mix in this analysis consists of a 50/50 mix of regional wind power and 1-axis tracking solar photovoltaic power on an installed capacity basis. The base case consists of no wind or solar power, and has a renewable penetration level of 8.95% due to the presence of small hydropower, biomass and geothermal power, matching levels present in 2005. Wind and solar capacities are then increased in a 50/50 mix up to a combined capacity of 300 GW. The maximum peak load in 2005 for CAISO was 45,451 MW [158], while the total available generation, which includes reserve capacity, is greater. Base load capacity levels are constant throughout the range and fixed at 2005 levels. The base case refers to the scenario with increasing renewable power capacities in the system without the presence of energy storage.

5.1.2.2.2.2. Energy Storage Scenarios

This analysis examines the sensitivity of the aforementioned metrics to the power and energy capacity of an aggregated energy storage system installed on the grid. In addition, the sensitivity to cost for different systems is explored. For grid-scale energy storage systems the most prominent technologies include pumped hydro, compressed air energy storage and flow batteries.

These technologies are unique in that the rated power for a unit is oftentimes independent of the energy capacity. For example, a pumped hydro facility can independently increase its instantaneous power generation capacity by installing more turbines (assuming that sufficient water can be sent to the new turbines) and the energy capacity can be increased by increasing the size of the reservoir.

Pumped hydropower is selected as the energy storage type with a round-trip efficiency of 75%, reflecting values found in the literature [81, 82]. The energy storage systems analyzed herein represent several different physical systems with the same power to energy ratio that are aggregated together into one system for analysis. Two sensitivities are performed: 1) Varying the power capacity of energy storage to explore system effects and 2) varying energy capacity of storage. The parameters for the power and energy capacity sensitivities are presented in Table 48 and Table 49:

Table 48 - Power Capacity Sensitivity for Energy Storage

Total Rated Power Capacity (GW)	Energy Capacity (GWh)	Energy Capacity (hours at rated capacity)
0.5	16	32
1	16	16
2	16	8
4	16	4
8	16	2
12	16	1.333
16	16	1
20	16	0.8

Table 49 - Energy Capacity Sensitivity for Energy Storage

Total Rated Power Capacity (GW)	Energy Capacity (GWh)	Energy Capacity (hours at rated capacity)
2	2	1
2	4	2
2	6	4
2	16	8
2	32	16
2	48	24
2	64	32
2	96	48

5.1.2.3. Results

5.1.2.3.1. Sensitivity of Technical Behavior to Energy Storage Power Capacity

This section explores the system level impacts of energy storage for varying power capacities.

The energy capacity is held constant at 16GWh, as shown in Table 48, while the power capacity is spanned between 0.5GW and 20GW of total energy storage power capacity.

5.1.2.3.1.1. Behavior of the Installed Renewable Capacity and Capacity Factor

The effect of energy storage power capacity on the installed renewable capacity is a function of two competing forces. First, the energy penalty of using the storage system acts to increase the

total energy of the load demand, requiring an increase in renewable capacity to meet a given penetration level. Second, the energy storage can enable the system to utilize otherwise excess renewable generation, decreasing the renewable capacity required to meet a given penetration level. The change in renewable capacity from the base value at different renewable penetration levels as a function of energy storage power capacity is presented in Figure 125.

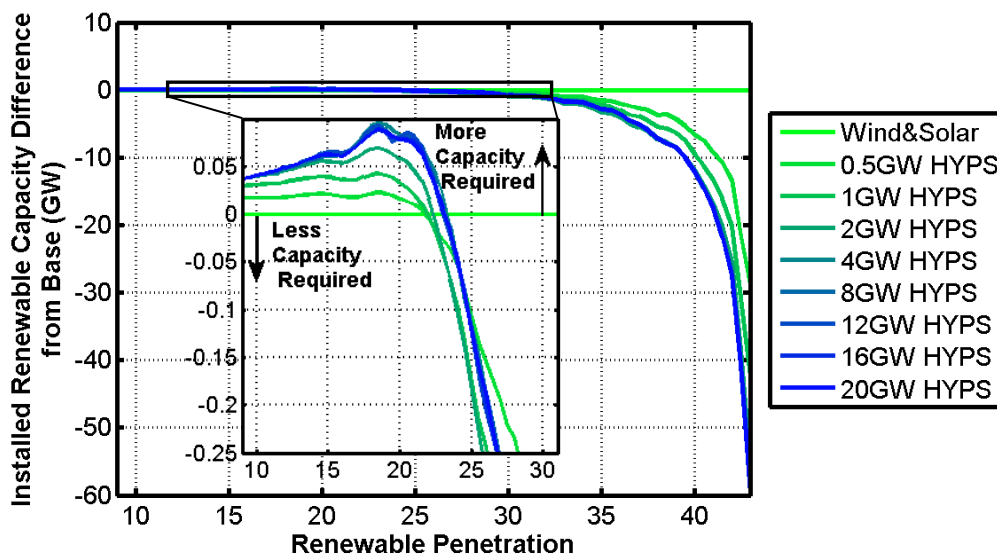


Figure 125 - Installed Renewable Capacity Difference from Base for Different Power Capacities with 16GWh of Storage for a 50/50 Mixture of Wind and Solar

At low renewable penetrations, the effect of the energy penalty dominates since little to no excess renewable generation is present. Increasingly more renewable capacity is required to meet a given renewable penetration level because of the non-coincidence of wind and solar generation with the electric demand. As the renewable penetration increases, this non-coincidence causes excess renewable generation to become available. The storage system is able to shift this energy to support the load demand using excess generation thereby offsetting the energy penalty. Larger power capacities allow larger utilization of this excess energy, contributing to decreases in the required installed renewable capacity.

Despite incurring an energy penalty, increasing the power capacity improves the system performance for all renewable penetrations. This is expressed by Figure 126, which shows the system-wide capacity factor and how it increases with the additional of energy storage.

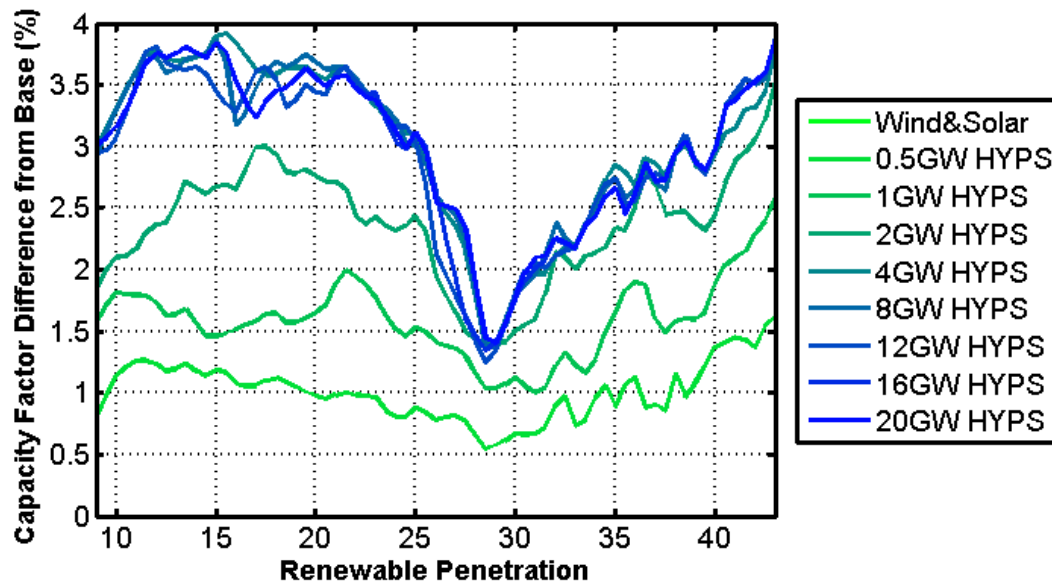


Figure 126 - Grid-wide Capacity Factor Difference from Base for Different Installed Capacities of Pumped Hydro with a 50/50 Mixture of Wind and Solar

This increase occurs due to the load-leveling effect of energy storage. By reducing the peak net load, a lower amount of balance generators need to be installed. By increasing the minimum net load, the installed generators can operate closer to their design capacity on average. Allowing the system to make use of otherwise curtailed renewable energy increases the utilization of given capacities of these resources. All of these factors combine to increase the grid-wide capacity factor. Larger power capacities allow the energy storage system to have higher load-leveling capabilities, especially given the peak-dominated nature of wind and solar power.

5.1.2.3.1.2. Behavior of the Balance Generator Ramp Rates and Start-up Events

In addition to increasing the capacity factor, energy storage has the ability to reduce the required fleet ramp rate to integrate renewables. Balance generation includes peakers and load-followers

and makes up the majority of generation that must ramp up or ramp down to accommodate both generation and demand changes on the grid. Figure 127 and Figure 128 show the ramp up and ramp down rates of the balance fleet for different installed capacities of energy storage. Ramp rates are similar in behavior and clearly show that with higher power capacity storage, operating to maximize renewable generation uptake (i.e., renewable integration mode), can reduce the ramping requirements of the fleet. As the renewable penetration increases beyond 40 percent, the excess renewable generation becomes so significant that the ramp rates fall. This is due to curtailment of excess generation providing dispatchability to the system as the demand fluctuates.

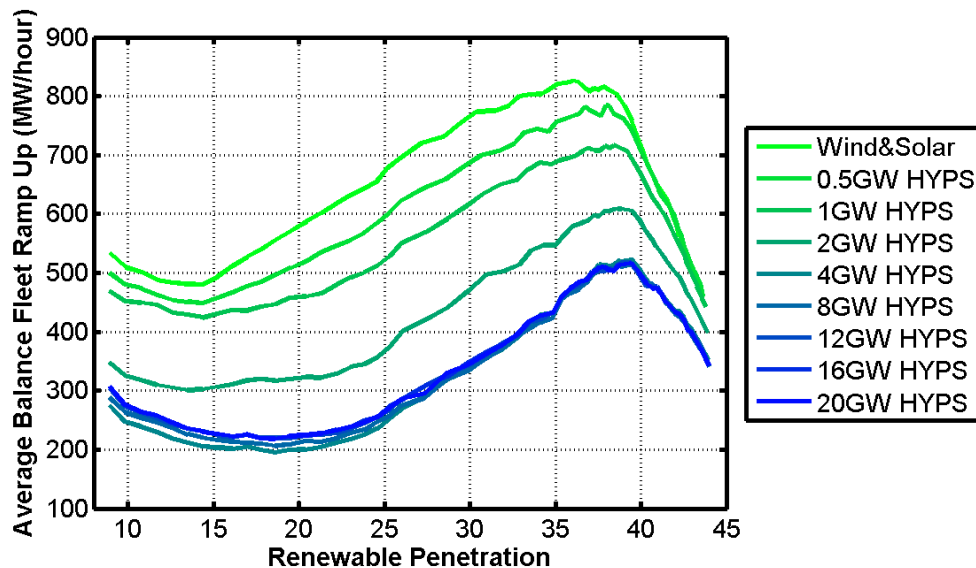


Figure 127 - Average Balance Fleet Generator Ramp Up for Different Installed Capacities with a 50/50 Mixture of Wind and Solar

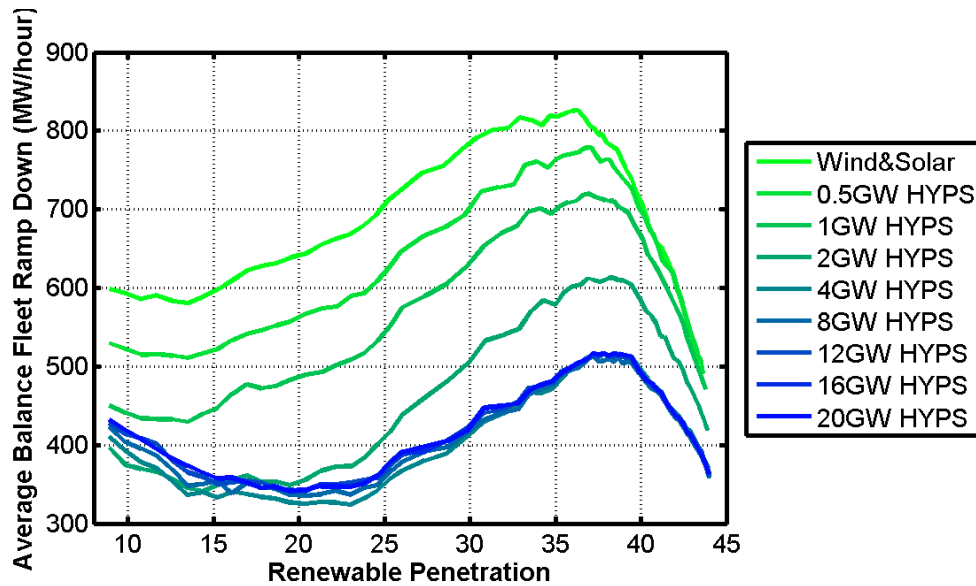


Figure 128 - Average Balance Fleet Generator Ramp Down for Different Installed Capacities with a 50/50 Mixture of Wind and Solar

The reduction in ramp rates is also expected due to the load-leveling effect of energy storage, which decreases the range of fluctuation of the net load demand, decreasing both up and down ramp rates. Larger power capacities bestow this ability to a larger extent, however, after a certain point, the load leveling ability of the system becomes limited by its energy capacity and no additional reductions in ramp rate are expected.

Average start-up event counts for the balance generation fleet could also be reduced on account of energy storage. Both peakers and load-followers experience a reduction in the number of starts per year. The average starts per generator, including both load-following and peakers, are shown in Figure 129.

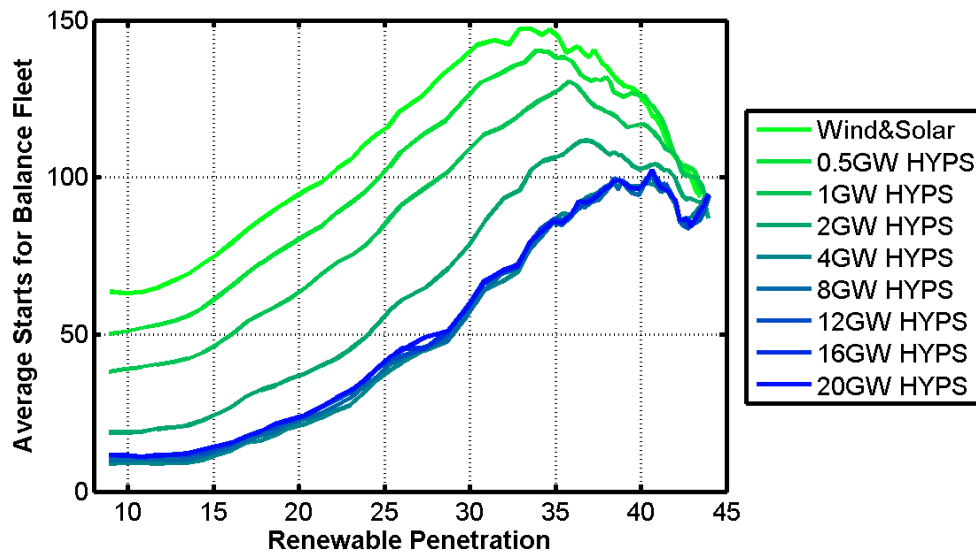


Figure 129 - Average Balance Fleet Starts Per Generator for Different Installed Capacities with a 50/50 Mixture of Wind and Solar

By reducing the range of fluctuation of the net load demand, fewer generators need to come online to meet large increases in the net load demand. Similar to the other results, increasing the power capacity of the system decreases starts to a larger extent up to a certain point where the effect becomes limited by system energy capacity.

Both ramp rates and start-up events exhibit increasing value with greater installed capacity but the rate at which the performance increases plateaus around 4GW of installed capacity. After this point additional capacity does little to reduce the balance fleet starts or ramp rates.

5.1.2.3.1.3. Behavior of the Grid CO₂ Emissions

Another key consideration for the implementation of energy storage into the system is for carbon dioxide emissions. Energy storage generally reduces CO₂ emissions but there are occasions when implementing energy storage can increase the CO₂ emissions related to fuel consumption compared to the base case with renewables alone as shown in Figure 130. For high renewable penetrations there is such a large amount of excess generation that the energy storage ceases to

be useful and if its operation is not managed appropriately (i.e., differently than for maximum renewable integration), it can cause an increase in the CO₂ emissions.

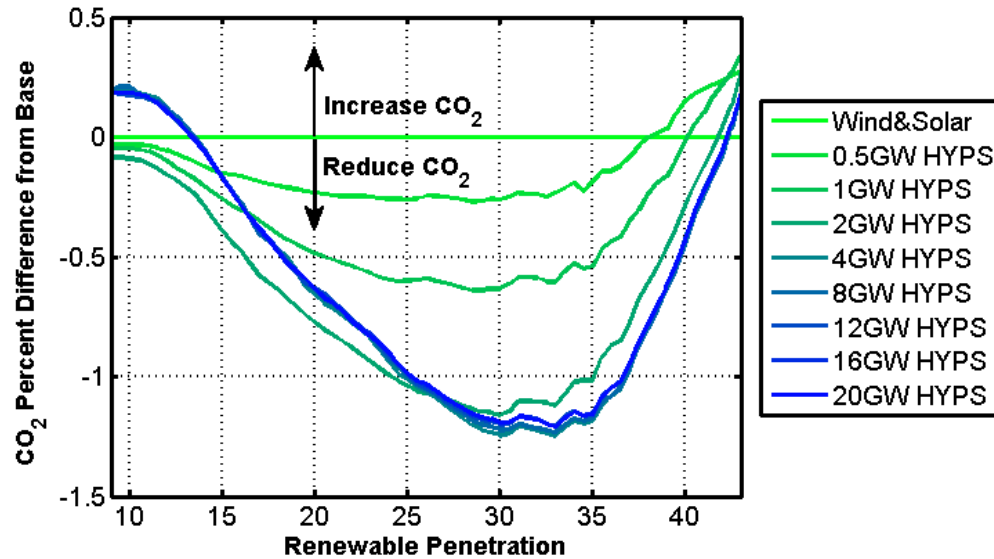


Figure 130 - Carbon Dioxide Emissions Difference from Base for Different Installed Capacities with a 50/50 Mixture of Wind and Solar

For low renewable penetrations, low capacities of energy storage reduce CO₂ emissions but beyond 2GW the initial emissions actually increase and are greater than that of lower power capacity systems until after 27% renewable penetration. This increase is related to the increase in emission from load-following units. Base load devices experience little to no effect on their operation from increasing renewable generation since these plants do not follow net load variations, therefore their emissions will remain unchanged. The two remaining CO₂ emitters are peakers and load-followers. The CO₂ from peakers reduces because their power profile is reduced by the energy storage. This will reduce CO₂ emissions from peakers but is only half of the story.

The other portion of emissions for low renewable penetration levels is from load-following plants. Load-following plants must generate additional power to accommodate the energy

penalty associated with storage devices thus their CO₂ emissions will increase. The storage system operates to smooth the load-follower operation and as the power increases, the largest movement occurs in the nighttime hours due to charging.

5.1.2.3.2. Sensitivity of Technical Behavior to Storage System Energy Capacity

This section explores the system level impacts of adjusting the energy capacity for a storage system, while holding the power capacity constant. The power capacity is held at 2GW and the storage duration is adjusted from 1 hour to 48 hours at rated capacity (i.e., 2 to 96 GWh of storage capacity).

5.1.2.3.2.1. Behavior of the Installed Renewable Capacity and Capacity Factor

Similar to the power capacity sensitivity, Figure 131 shows that due to the energy penalty storage devices only increase the renewable penetration once excess renewable generation can be utilized. Larger energy capacities, increase the generation required to make up for the energy penalty so they also reduce the renewable penetration the most initially; however, as soon as sufficient excess generation is available (i.e., around 23%) high energy capacities quickly begin to reduce the required renewable capacity to achieve a given penetration.

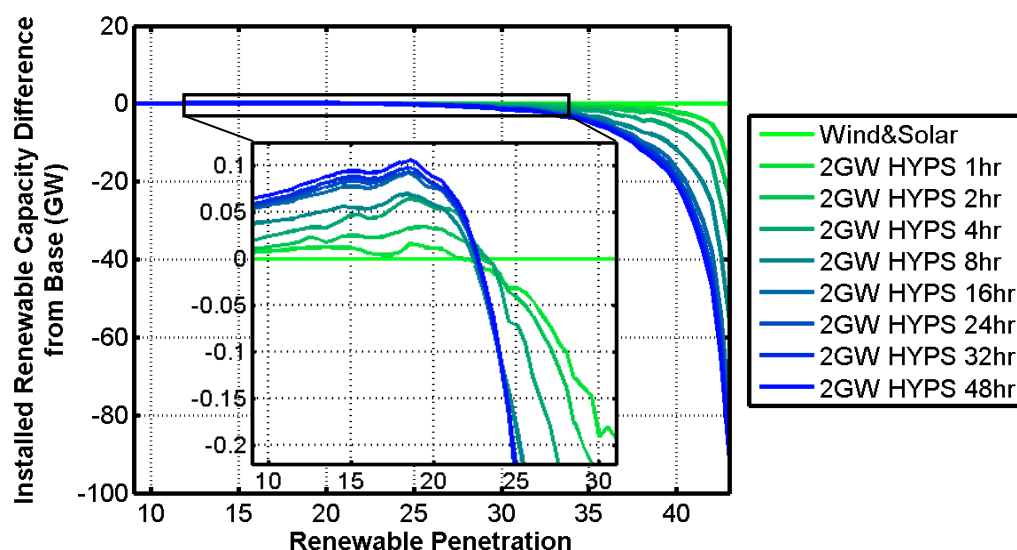


Figure 131 - Installed Renewable Capacity Difference from Base for Different Energy Capacities with 16GWh of Storage for a 50/50 Mixture of Wind and Solar

These effects are similar to that displayed by the power capacity sensitivity, where the effect of energy storage is increased with higher energy capacities up to a point, where utilization becomes limited by power capacity.

The capacity factor for cases with different energy capacities is similar to that of the power capacity cases. Figure 132 indicates that including energy storage will increase the system-wide, yearly capacity factor, as presented as a difference from the base case with no energy storage, (i.e., “Wind&Solar”).

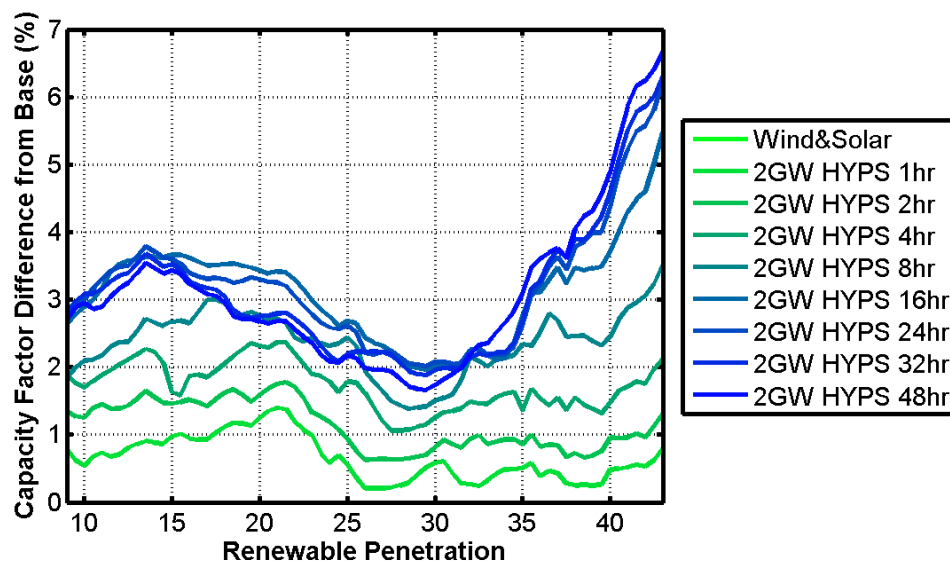


Figure 132 - Grid-wide Capacity Factor Difference from Base including Energy Storage and Those without Energy Storage for a 50/50 Mixture of Wind and Solar

These effects parallel that of the power capacity sensitivity, with increases occurring until power capacity limits the load-leveling ability of the system.

5.1.2.3.2.2. Behavior of the Balance Generator Ramp Rates and Start-up Events

Varying the energy capacity of the system results in reductions of the average ramp rate up as

shown in Figure 133 and ramp rate down as shown in Figure 134. Limiting the capacity to 2GW

also limits the effectiveness of the ramp rate reduction. When compared with the results for the power capacity sensitivity, it is apparent that power capacity is a more important factor for reducing the balance fleet ramp rate. Similar to the power capacity sensitivity, a reduction in ramp rate at high penetrations is experienced due to the use of curtailment of excess generation to provide system dispatchability.

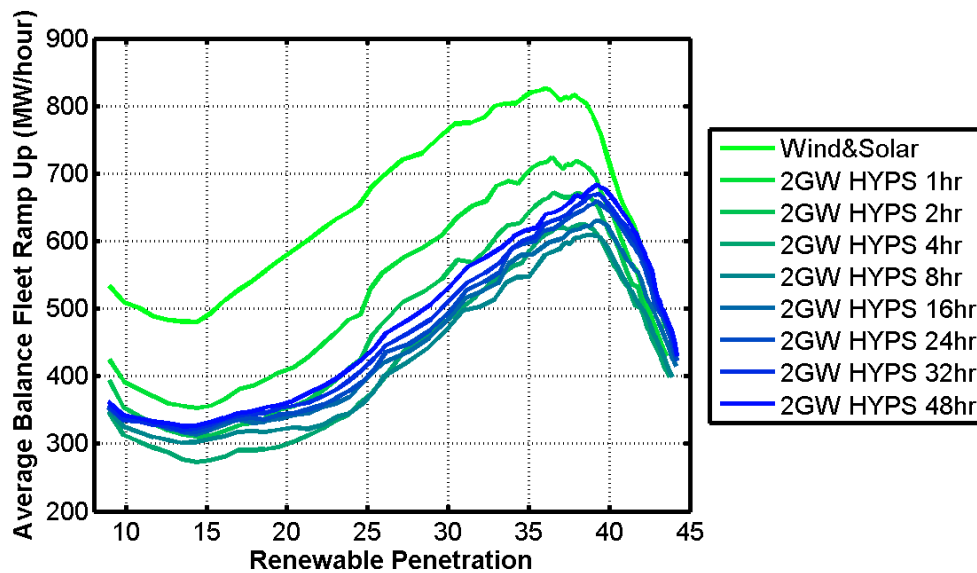


Figure 133 - Average Balance Fleet Generator Ramp Up for Different Energy Capacities with a 50/50 Mixture of Wind and Solar

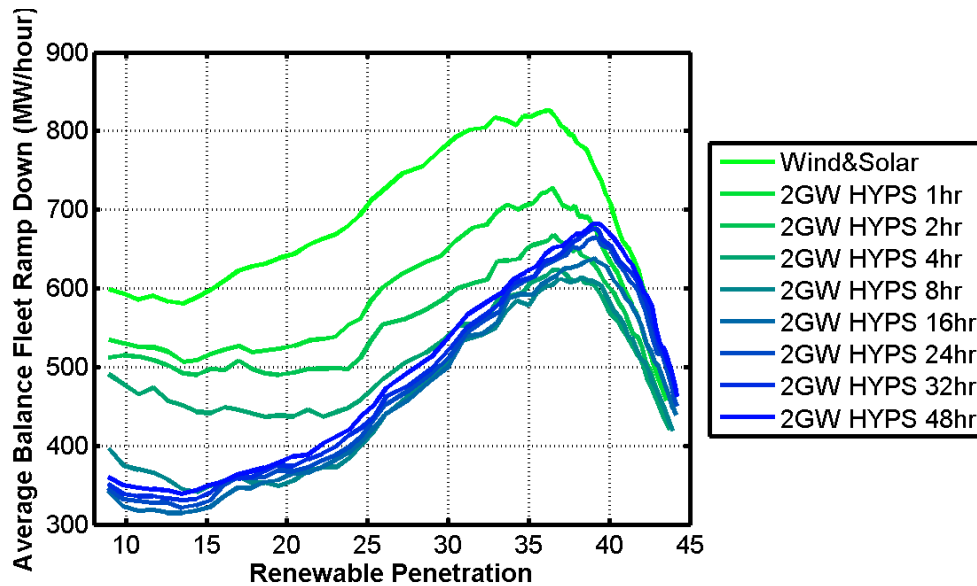


Figure 134 - Average Balance Fleet Generator Ramp Down for Different Energy Capacities with a 50/50 Mixture of Wind and Solar

These results are somewhat different than that displayed by the power capacity sensitivity.

Increasing the energy capacity of the system decreases ramp rates to a point, after which without increases in the system power capacity, the ramp rates start to increase slightly (but still remains well below levels in the cases without energy storage). This occurs since with a limited power capacity, the system has a limited ability to reduce net load peaks and increase net load valleys, the difference of which determines the ramp rates. At the same time, increased energy capacity indicates that more energy is passing through the system, causing the energy of the load demand to increase, subsequently increasing the energy of the net load demand and its range of fluctuation slightly. This starts to counter the effect of the energy storage system to some degree.

Reducing the average yearly starts for the balance fleet is achievable with all values of energy capacity; however, as the capacity is increased over 4GW the starts do not reduce but rather stay around the same value. Thus selection of energy capacity to match power capacity is important

when considering the effect of energy storage on capacity factor, fleet ramp rates and generator starts.

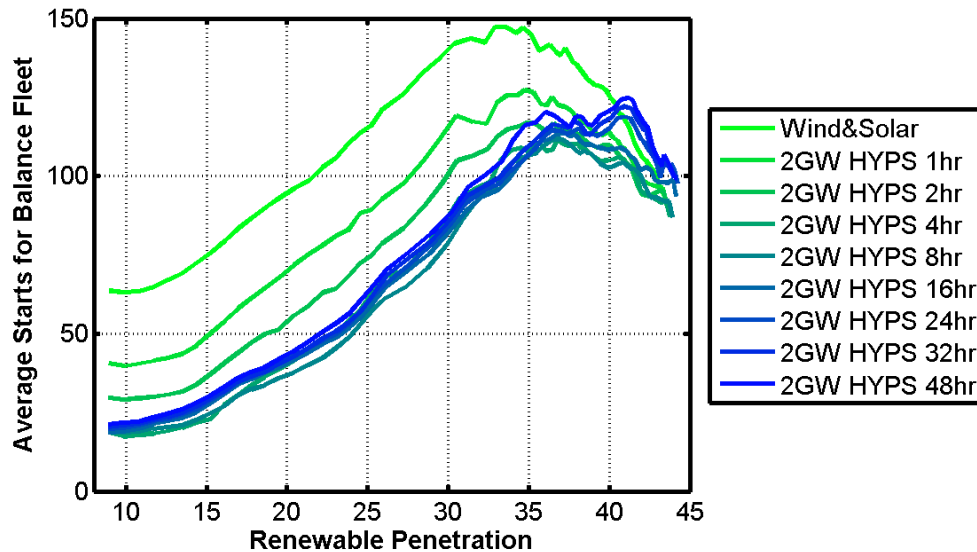


Figure 135 - Average Balance Fleet Starts for Different Energy Capacities with a 50/50 Mixture of Wind and Solar

5.1.2.3.2.3. Behavior of the Grid CO₂ Emissions

Figure 136 shows the effect of increasing energy capacity on CO₂ emissions compared to the base case with renewables alone. Similar to Figure 130, the selection of capacity can improve or deter CO₂ reductions. The maximum CO₂ reduction occurs for 8 hour capacity, while any larger capacity will cause the CO₂ emissions to increase initially and again at very high renewable penetrations. As described previously for the power capacity, this increase is as a result of the energy penalty that must be overcome initially and the large amount of excess generation at high penetrations.

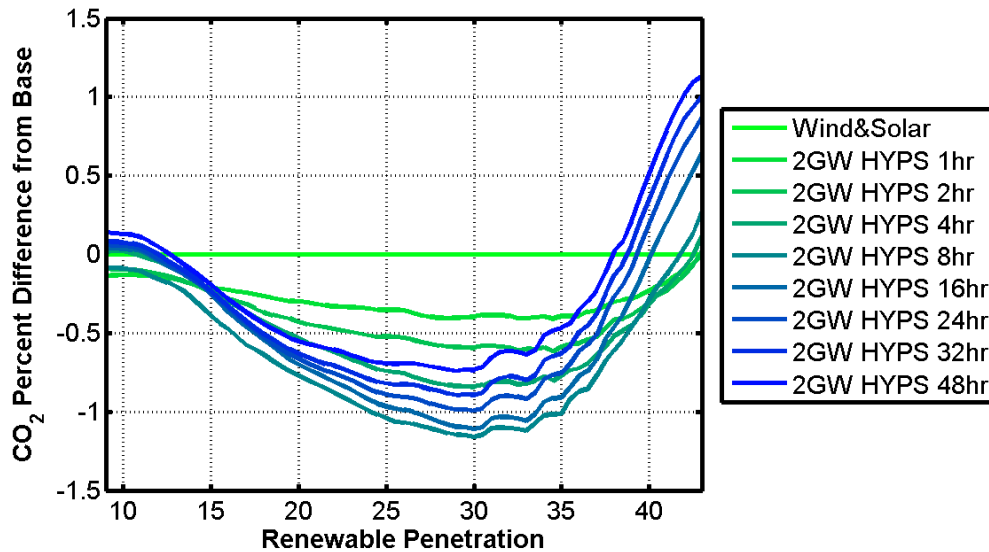


Figure 136 - Carbon Dioxide Emissions for Different Installed Capacities with a 50/50 Mixture of Wind and Solar

5.1.2.3.1. Sensitivity of Economic Behavior

5.1.2.3.1.1. Behavior of the Levelized Cost of Electricity

Using the resulting generation profiles along with the cost values, the effect on the levelized cost of electricity (LCOE) can be explored. The cost competitiveness for energy storage technology can be assessed by comparing the cost without energy storage to the case with energy storage. Cost values for pumped hydro energy storage are selected as shown in Table 50 and represent a combination of values from the CEC COG model [234] and a report from the Electric Power Research Institute [86].

Table 50 - Input Parameters for Pumped Hydro Energy Storage

Pumped Hydro Input Parameters	Values
Instant Cost (\$/kW)	2,500
Fixed O&M (\$/kW-yr)	35
Variable O&M (\$/MWh)	7
Transmission Cost (\$/MWh)	4.3
Debt Term (Yrs)	20
Economic Life (Yrs)	40
Federal Tax Life (Yrs)	20
State Tax Life (Yrs)	20
Ad Valorem Tax Rate	1.1%
Start-Up Fuel (MMBtu/MW)	0
Plant Losses	0%
Transmission Losses	5.0%
Transformer Losses	0.5%

Figure 137 shows the technology specific levelized costs for each generating technology that makes up the grid mixture with energy storage and Figure 138 represents the case without energy storage. “Complementary” represents a 4GW HYPS energy storage system. LCOE values for hydro, nuclear, coal, geothermal, and load-following generation represent fully depreciated assets (i.e., no capital investment is required only fuel and operation and maintenance (O&M) costs). The initial peaker fleet is considered to be fully depreciated but if additional plants must be installed to compensate for the changing demand shape they are installed as new, non-depreciated plants and are assessed a capital cost.

Due to the operation strategy, the load-following LCOE is reduced for the energy storage case since greater energy from the renewables can be harnessed thereby reducing the number of required load-following plants and the load swings to which they are subjected. The peaker

LCOE is not always less for the energy storage case. This is due to several factors. First, energy storage acting to increase renewable penetration does not specifically focus on reducing peaker generation, though that is an important topic for future research and presents a valuable opportunity for energy storage devices.

As the penetration increases, the LCOE of energy storage reduces. This is on account of the ability to increase the amount of energy shifted as the penetration increases while maintaining the same capital cost and very similar O&M cost.

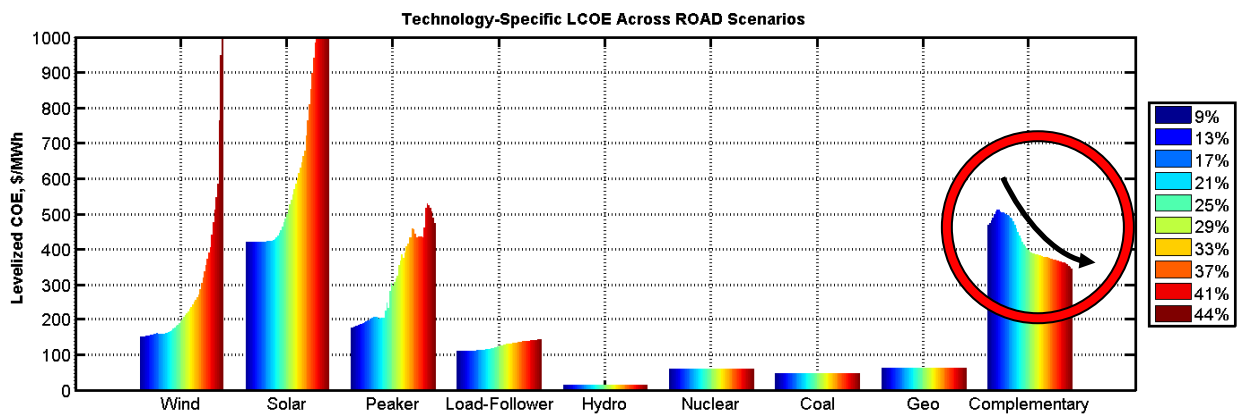


Figure 137 - Technology Specific Levelized Cost of Electricity for each Generation Technology with 4GW of 8 Hour Pumped Hydro with a 50/50 Mixture of Wind and Solar

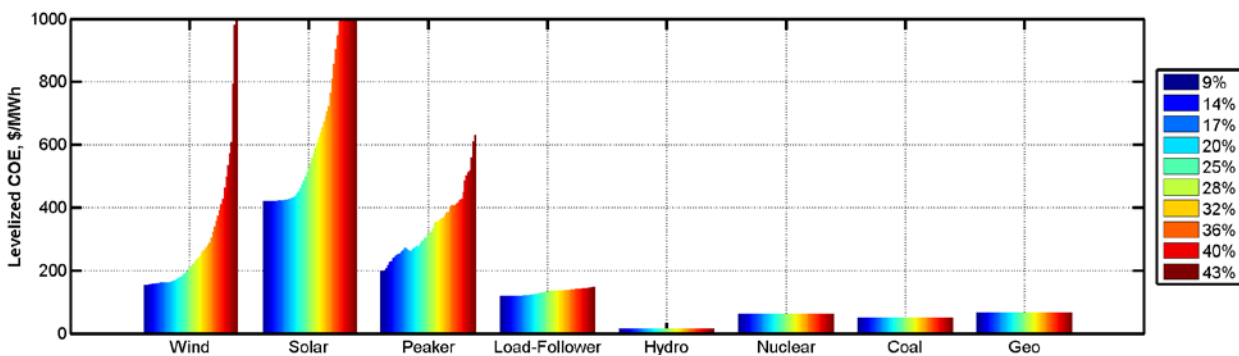


Figure 138 - Technology Specific Levelized Cost of Electricity for each Generation Technology Excluding Energy Storage with a 50/50 Mixture of Wind and Solar

For energy storage systems to be cost competitive they must provide enough value to balance their capital and O&M costs including the energy penalty for storing energy. If the system-wide LCOE for the case with energy storage is less than that of the case without energy storage for a specific renewable penetration then energy storage is instantly valuable and should be installed. If the opposite is true then its value while operating in renewable integration mode does not warrant installation from a cost perspective. As the renewable penetration increases the value of energy storage increases for a few reasons. First, energy storage LCOE generally reduces with increasing penetration due to an increase in the energy generated. Second, the cost of renewables increases non-linearly for several reasons including 1) progressively lower capacity factor with increasing installed renewable capacity even when considering geographic diversification, 2) the need to maintain grid reliability by acquiring reserve capacity and additional regulation due to intermittent behavior, and lastly 3) high penetrations experience excess generation of renewables that, if not utilized, can exponentially increase the LCOE.

Figure 139 presents the value of energy storage for each power capacity value. Note that positive values represent reductions in the levelized cost of electricity compared to the base case, as the LCOE difference is defined here as:

$$\Delta LCOE [\%] = \left(\frac{LCOE_{base} - LCOE_i}{LCOE_{base}} \right) \times 100$$

For technologies that are not initially cost competitive, locating the crossover point (i.e., the renewable penetration after which the technology is competitive in the market) is critical to comparing different energy storage types and strategies from a cost perspective. Initially, larger power capacities are less competitive. The 0.5 and 1 GW cases are always cost competitive and will lower the system LCOE in all cases as a result of the low capital investment of pumped

hydro. A 2GW installation starts cost competitive, dips slightly below the line around 11% and then increases in competitiveness beyond the 0.5GW for the remainder of the scenario. The other power capacities, though they provide superior performance advantages are not initially cost competitive. It is not until higher penetrations that the storage becomes cost competitive with the current grid (24%, 35%, etc.). As a reminder the competitiveness of each technology is based on operation to support renewable integration, not specifically for peaker support or ancillary service provision, though some of that behavior is experienced in the renewable integration strategy.

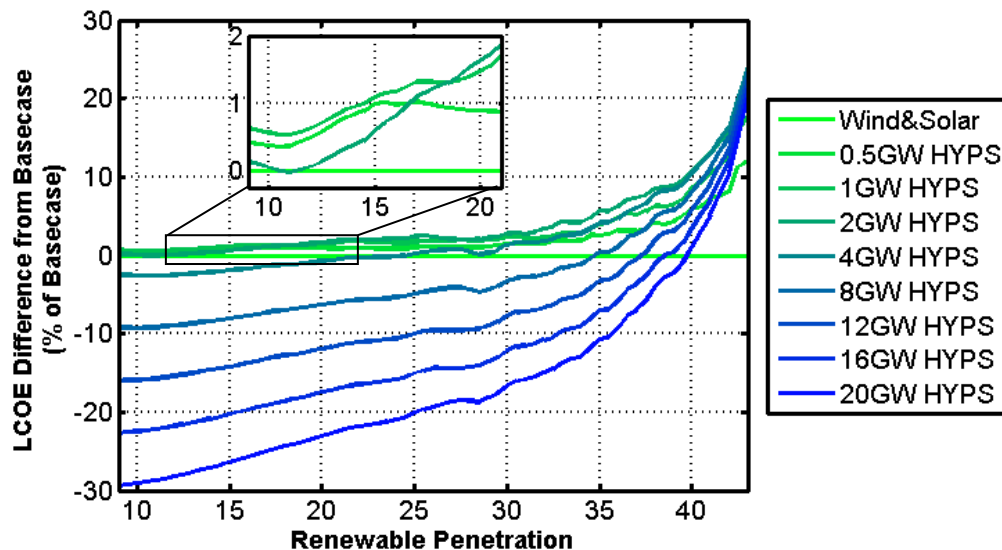


Figure 139 - Levelized Cost of Electricity Difference from Base Comparison between All Power Capacity Cases for 16GWh Capacity with a 50/50 Mixture of Wind and Solar

By averaging the LCOE difference value from Figure 139 for each renewable penetration, the average value for each scenario is calculated in Table 51. This shows that for different power capacities with 16 GWh energy capacity, that 2 GW is the preferred power capacity to achieve the maximum value over the lifetime of the system for all renewable penetrations.

Table 51: Average Value for Various Power Capacities per Renewable Penetration

Total Rated Power Capacity (GW)	Energy Capacity (GWh)	Average LCOE difference from base case across all penetrations
0	0	0 (base case)
0.5	16	2.13
1	16	3.24
2	16	3.99
4	16	2.25
8	16	-2.43
12	16	-7.15
16	16	-11.82
20	16	-16.46

Smaller energy capacity systems are less cost competitive than larger capacity systems. The biggest reason for this is because the cost is assessed based on installed capacity (i.e., \$/kW) and not on energy capacity. Variable operation and maintenance is charged on a per energy basis (i.e., \$/kWh) and that is one reason that the larger capacities are the most valuable. Increased generation from systems with larger energy capacity should reduce the LCOE for the system but from a combination of the energy storage charging penalty and the variable O&M cost, the value of those systems can vary depending on the specific hourly operation of each system.

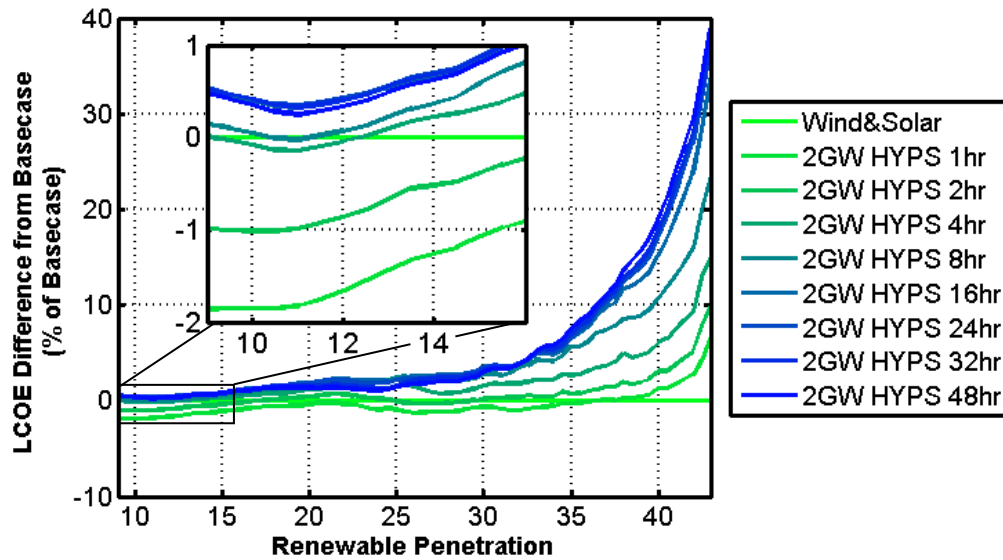


Figure 140 - Levelized Cost of Electricity Difference from Base Comparison between All Energy Capacity Cases for HYPS with a 50/50 Mixture of Wind and Solar

To find the most cost effective solution over the entire lifetime of the system, the average is taken for each energy capacity of the LCOE difference from the base case. The results are presented in Table 52. A system with 2GW has the greatest value at the highest energy capacity (i.e., 96 GWh or 48 hours at rated capacity) for the reasons described in the previous paragraph.

Table 52 - Average Value for Various Energy Capacities per Renewable Penetration

Total Rated Power Capacity (GW)	Energy Capacity (GWh)	Average LCOE difference from base case across all penetrations
0	0	0 (base case)
2	2	-0.41
2	4	0.71
2	6	2.26
2	16	3.99
2	32	5.32
2	48	5.68
2	64	5.74
2	96	5.88

5.1.2.4. Summary and Conclusions

5.1.2.4.1. Power Capacity Sensitivity Summary

- Increasing power capacity increases the energy that can be shifted, until further utilization is limited by the energy capacity.
- Energy storage can increase the achievable renewable penetration but must first overcome the efficiency penalty for storing electricity.
- Energy storage can increase the system capacity factor for all renewable penetrations
- Energy storage can reduce balance fleet ramping and reduce balance fleet starts for all renewable penetrations and particularly at low penetrations
- CO₂ emissions can be reduced from the use of energy storage but the power and energy capacity must be carefully selected to avoid an increase on account of a high energy penalty for using the storage.
- Value for energy storage is a balance between reduction in generator dynamics and the energy penalty for storing energy. Capacities below represent values beyond which the additional performance is greatly diminished or negligible:
 - 20 GW (maximum option) for maximizing the renewable penetration

- o 8 GW for maximizing capacity factor
 - o 4 GW for minimizing ramp rates and balance fleet starts
 - o 2 GW for minimizing CO₂ emissions
- For systems with the same energy capacity, increasing power capacity will eventually provide diminishing performance increases for capacity factor, efficiency, ramp rates and starts

5.1.2.4.2. Energy Capacity Sensitivity Summary

- Increasing energy capacity increases the amount of energy that can be shifted by increasing the time window when energy is available to store.
- Larger energy capacities increases the additional generation required to store the energy and in turn the energy storage penalty
- The benefits of increasing the energy capacity must outweigh the energy penalty for charging and discharging the storage system
- Larger energy capacities can increase the capacity factor, reduce the ramp rates up and down, the average balance fleet starts and CO₂ emissions with respect to smaller capacities; however, there is a limit to the value of increasing the capacity. Capacities below represent values after which the additional performance is greatly diminished or negligible:
 - o 48 hours at rated capacity (maximum option) for enhancing renewable penetration
 - o 16 hours at rated capacity for increasing capacity factor
 - o 8 hours at rated capacity for minimizing CO₂ emissions
 - o 4 hours at rated capacity for minimizing ramp rates and generator starts

5.1.2.4.3. Economic Behavior Sensitivity Summary

- Different operation strategies (e.g., renewable integration, ancillary service, peaker support) should be explored to compare the differences in value
- Energy capacity and power capacity should be sized appropriately to minimize cost, in addition to maximizing performance.
 - 2GW power capacity with 16 GWh of storage is the most cost effective among the power capacity options
 - 48 hours at rated capacity (maximum option) is the most cost effective among the energy capacity options
- Energy storage must balance value to the grid with capital and O&M costs including the energy penalty for storing energy

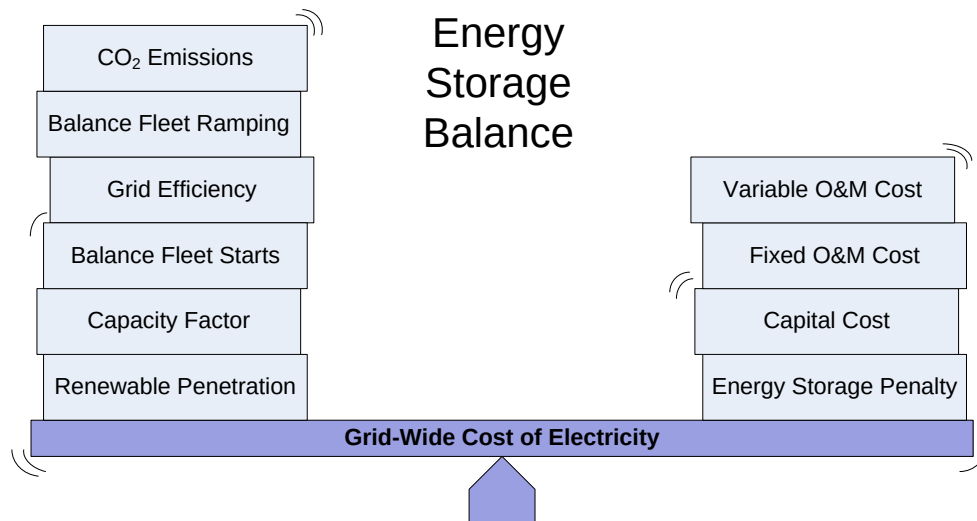


Figure 141 - Factors Affecting the Cost Competitiveness of Energy Storage

5.1.2.4.4. Conclusions

A study was conducted to characterize the effectiveness of implementing energy storage of different energy and power capacities in the context of supporting increased variable renewable generation on the electric grid. The key points are summarized as follows:

1. Energy storage can improve system performance in many aspects, but certain benefits require overcoming of the energy penalty for using the system to be realized. The use of energy storage was shown to increase the achievable renewable energy penetration and system capacity factor, these benefits are garnered only when the increased load-shaping capability outweighs the energy penalty of using the system, however. Energy storage was also able to decrease balance fleet ramping and generator starts compared to the case without energy storage.

2. Selection of the power and energy storage capacity of the system is important. Depending on which particular metric is desired to be optimized, the most effective power and energy capacities of the energy storage system can be different. This was most prevalent with the effect on CO₂ emissions, but is also prevalent for other metrics. While it is not always possible to have control over the ratio of power to energy capacity, results show that it is important to determine the desired roles of using energy storage on the electric grid in the context of renewable integration and size the system to most effectively fulfill those roles.

3. The cost-competitiveness of energy storage is a tradeoff between the economic benefit of improving system performance and the capital, operation and maintenance costs, and the costs associated with the energy storage penalty. Energy storage is able to provide a wide range of technical benefits to the electric grid in the support of integrating variable renewable power. The value of the different benefits varies, however. Depending on policy structures and technology evolution in balancing generators, some benefits may be more valuable than others and may affect the cost-competitiveness of this system more strongly.

Overall, the aggregate value of all benefits for a particular storage system configuration must outweigh the costs to implement and operate that system to be cost-competitive.

4. The incremental benefits of implementing energy storage can start to diminish as the system size increases. Larger energy storage systems tended to impart larger improvements in system performance. After a certain point, however, the incremental increase in performance for an increase in system capacity starts to diminish. Large increases in performance are obtained for a fixed increase in system capacity at lower system capacities, but smaller increases in performance occur for the same increase in system capacity when the system is already large. This occurred essentially for all of the metrics displayed here.

Overall, the use of energy storage can be quite effective in improving the technical and economic performance of the electric grid in the context of increased renewable energy integration into the system. The extent and value of this effectiveness, however, depends on the consideration of many factors and the role which energy storage is selected to fulfill. In order to have an understanding for what roles energy storage should ideally fulfill and how much of these roles it should fulfill requires mapping out the effectiveness of other complementary technologies in these different roles as well and optimizing the mix. This is a topic for future work.

5.1.3. Complementary Technologies: Demand Response

Certain results and figures text have been presented with modification from the following publications:

- Samuelsen, S., Mueller, F., Eichman, J., **Tarroja, B.** Advanced Power and Energy Program. 2013. *Piloting the Integration and Utilization of Renewables to Achieve a Flexible and Secure Energy Infrastructure*. California Energy Commission. Publication number: CEC-PIR-08-033.

5.1.3.1. Literature Review

The use of demand response as a complementary technology for supporting the integration of renewable resources has also been discussed in the context of sustainability. Sioshansi [235] studied the effect of employing real-time price signals in the Texas power system with large capacities of wind power generation. The real-time price signals were intended to reflect the cost of serving load and wind generation was assumed to operate at no cost. Therefore, the real-time price signals reflected the cost of balancing generation and incentivize end users to tailor their load demand to complement wind generation. Results showed that using real-time pricing to incentivize demand response increased the energy contribution of wind power to the load and therefore increased the renewable penetration level for a given wind capacity. The profile of the resulting load demand also displayed shifting of load from traditionally on-peak times to off-peak times. Additionally, many types of controllable loads and demand response strategies such as lighting, temperature adjustment, ventilation fans, and precooling have been identified [59, 92, 236]. Major applications include peak shaving, provision of contingency reserve capacity, regulation-up capacity and energy consumption reduction, with restrictions primarily based in the nature of the controllable load mix and climate region.

While the performance of energy storage and demand response has been examined to some extent, much of these efforts have taken place in small scale or isolated systems. There are only a few studies in the literature that examine these applications on the large scale within the context of supporting renewable generation. Additionally, there has not been much insight into the explicit effect of the use of energy storage and demand response on the performance of the grid and the design and operation of load-balancing resources that manage the system within the context of renewable power generation. This study aims to shed some insight into how energy

storage and demand response affects can grid operations and the value of such systems to the grid overall.

5.1.3.2. Approach

5.1.3.2.1. Metrics

This analysis is aimed at examining the effectiveness of demand response in supporting the integration of variable renewable power on the utility grid. The metrics used to characterize this effectiveness are the exact same as those used for the renewable capacity spanning analysis presented in Section 5.1.1.

5.1.3.2.1. Scenarios for Analysis

5.1.3.2.1.1. Renewable Mix

The renewable mix in this analysis consists of a 50/50 mix of regional wind power and 1-axis solar photovoltaic power on an installed capacity basis. The base case consists of no wind or solar power, and has a renewable penetration level of 8.95% due to the presence of small hydropower and geothermal power, matching levels present in 2005. Wind and solar capacities are then increased in a 50/50 mix up to a combined capacity of 300,000 MW. Base load capacity levels are constant throughout the range and fixed at 2005 levels.

5.1.3.2.1.2. Demand Response Scenarios

The three major strategies explored in this study include an “all energy” strategy where all available DR is utilized for reducing the demand, an “all spinning reserve” strategy where all available DR is maintained for spinning reserve purposes and does not reduce the demand and lastly a “peaker only” strategy, where all available DR reductions are used to displace power that would otherwise have to be generated by peakers.

There are three strategies employed as the boundaries of DR operation including:

- **All Energy (AllE):** involves using all DR capacity available, all the time for reducing the demand. This behavior is similar to a base load reduction.
- **Peaker Only (PKonly):** Information about the operation of the grid is input into the DR model and the peaker signal is minimized. In other words, PKonly operates all the hours that the peakers are operating above their minimum set point and can provide as much DR capacity as is available but will not exceed the energy of the peaker signal.
- **All Spinning Reserve (AllSP):** The DR capacity for each hour of the day is directed toward meeting spinning reserve. In this way, the DR never reduces the demand, but by reducing the spinning reserve it removes the burden from other dispatchable generation to provide spinning reserve services.

For all three strategies the most energy is available in the afternoon when temperatures are highest so the fans are, on average, at their highest set point. All demand response scenarios are conducted assuming a high occupant impact level (impact level 3) for lighting and fan turndown. In this manner, the maximum potential effect of using demand response in each of the three strategies described prior can be determined.

5.1.3.3. Results

5.1.3.3.1 Sensitivity of Technical Behavior to Demand Response Application

5.1.3.3.1.1 Behavior of the Installed Renewable Capacity and Capacity Factor

The change in the installed renewable capacity required to reach a given renewable penetration level is presented in Figure 142:

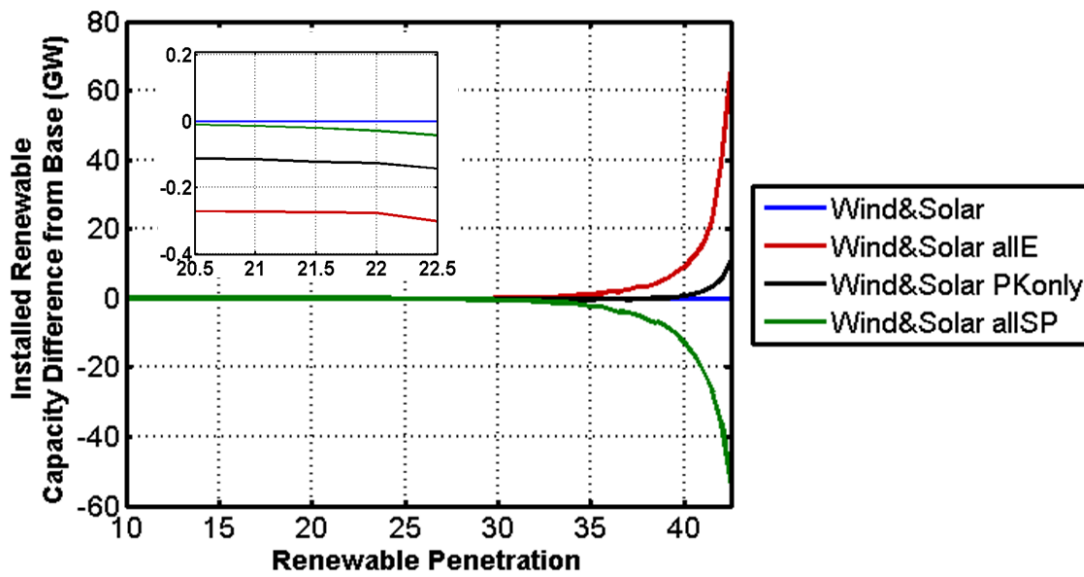


Figure 142 - Installed Renewable Capacity Difference from Base for Different DR Application Strategies

Below the 30% renewable penetration level, the use of demand response in any of these three strategies has very little effect on the installed renewable capacity required to reach a given renewable penetration level. In this region, the all energy case shows the largest reduction of the three strategies since this strategy decreases the energy of the load by the largest amount. The use of demand response for spinning reserve has almost no effect on installed renewable capacity, since it does not alter the load profile and only enables balancing generators to operate over larger part-load ranges.

Above the 30% renewable penetration level, the effect on installed renewable capacity becomes noticeably different. The all-energy application of demand response actually increases the capacity of renewables needed to meet a given renewable penetration level. This occurs since in the all-energy application, load is being reduced without considering the behavior of renewable generation. This leads to events where load is reduced during a period of high renewable generation, causing such generation to be curtailed instead of serving the load due to the

presence of uninterruptible base load generation that cannot turn down. This emphasizes the importance of coordinating the use of demand response with renewable generation. The case that applies demand response for meeting spinning reserve decreases the renewable capacity required to meet a given renewable penetration level. This occurs since it decreases the amount of load-following units that are required to be online to meet spinning reserve, allowing a larger portion of the load demand to be served by renewable generation.

The peaker support case shows no change in the required installed renewable capacity for most of the renewable penetration range, but at very high renewable penetration levels (above 41%), a slight increase in required renewable capacity occurs. This occurs because peakers are still activated during hours of excess renewable generation to meet spinning reserve capacity that load followers are unable to meet. The spinning reserve profile varies throughout the day, tending to increase during the daytime hours. This profile is not affected by the behavior of renewable generation, since the contingencies that spinning reserve must respond to affect the system at much faster timescales [237, 238]. Therefore, instances occur when an increase in spinning reserve requirement occurs when load-following units are already at their maximum power, and meeting the spinning reserve increase would require activating another load-following unit. When these units are activated, however, they have a minimum operational time of 8 hours. Many surges in the required spinning reserve capacity have shorter durations than 8 hours, requiring peakers to be brought online. This occurs even though excess renewable generation is present, since variable renewable power cannot provide spinning reserve capacity in these cases. This causes the demand response measures in this case to respond to peaker activation by reducing the load demand during these times, creating more curtailment in a manner similar to the all-energy case and increasing the required installed renewable capacity.

The use of demand response for spinning reserve allows decreases in the required installed renewable capacity, since it frees up dynamic capacity in balancing generators. By allowing balancing generators to be more flexible, specifically to allow operation at lower part-load levels, the uptake of renewable generation that would have otherwise been curtailed is increased. This acts to increase the renewable penetration level for a given installed renewable capacity.

Use of demand response also affects the system capacity factor. Installing renewables the capacity factor will steadily drop as has been shown but the effect from demand response depends on the bounding stage employed. By focusing the strategy on all energy, the capacity factor will not improve because the profile effectively behaves as a base load technology as shown in Figure 143. As the renewable penetration increases the base load profile actually precludes the uptake of additional renewables so there is reducing value of using the all-energy strategy because it does not intelligently affect the balance profile. Reducing peaking capacity has a positive effect on the capacity factor with a slight increase for the majority of renewable penetrations. This is because the demand response is focused on reducing the number of peakers and in so doing increases their capacity factor which increases the system-wide capacity factor. As the renewable penetration increases, the value of controlling peakers is decreased. This is because with higher renewables, the excess generation increases and provides some firming of the renewables thereby lowering the need for peakers.

Alternatively, the spinning reserve application of demand response causes significant increases in the grid capacity factor at high renewable penetration levels. This allows a reduction in curtailment and an uptake of renewable generation which increases the grid capacity factor as explained previously.

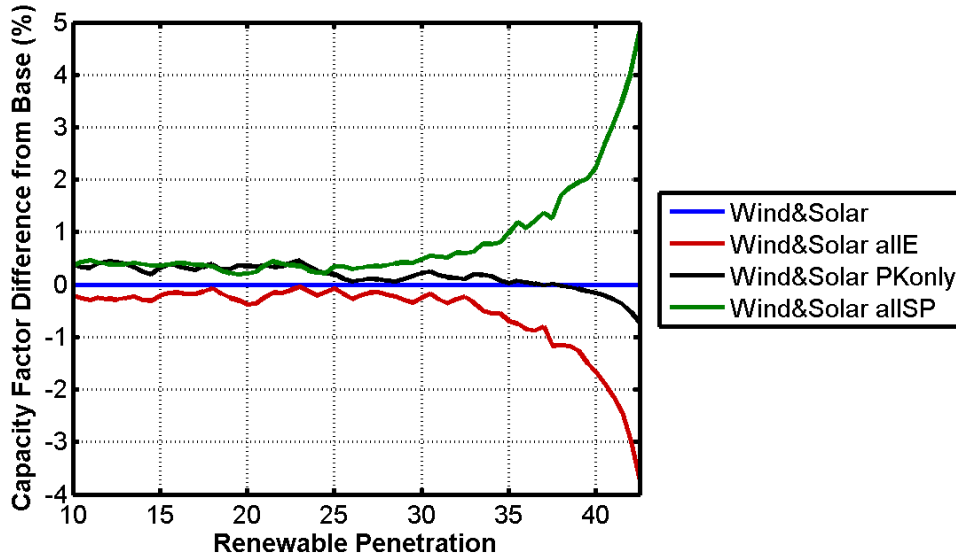


Figure 143 - Effects of Demand Response Bounding Strategies on System Capacity Factor as a Difference from Base Case

5.1.3.3.1.2. Behavior of the Balance Generator Ramp Rates and Start-up Events

The use of demand response also has the potential to affect generator ramp rates and start-up

events. Since demand response measures are not load-shifting measures and typically do not

have the flexibility to shape the load demand in the same manner as energy storage, the effects of

using these measures on balance ramp rates will be much different than that of energy storage.

The average ramp-up and ramp-down rates for the balancing generator fleet are presented in

Figure 144 and Figure 145:

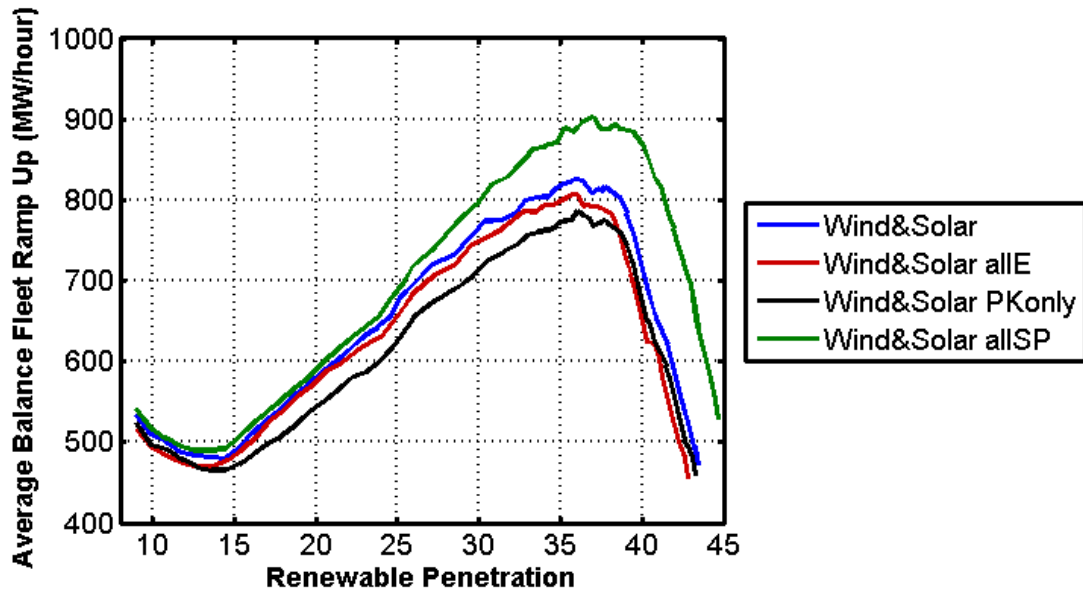


Figure 144 - Average Balance Fleet Generator Ramp Up for Different DR Application Strategies

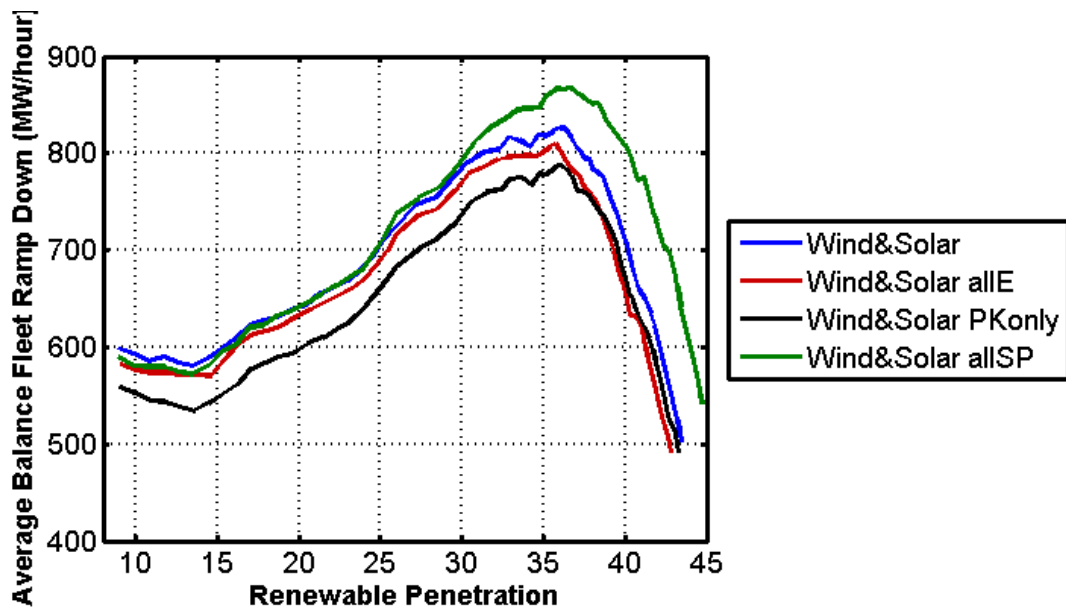


Figure 145 - Average Balance Fleet Generator Ramp Down for Different DR Application Strategies

The effects of the different demand response strategies on balance generator fleet ramp rates are similar for both up and down ramping. The peaker support case exhibits the largest reduction in balance fleet ramp rates. Peakers typically exhibit the highest ramp rates since these units are typically tasked with meeting the quick transients in the bulk net load demand, and using demand

response to fill this function reduces reliance on these generators and reduces the ramp rates. The all-energy case reduces ramp rates very slightly compared to the base case, simply by virtue of reducing the load during most of the hours of the day, reducing the peak net load and therefore the ramp rate needed to meet it. The use of DR for spinning reserve increases the ramp rates of the balancing generator fleet, especially at high renewable penetration levels. This occurs because a certain amount of load followers are tasked with being online at all times to meet a portion of the required spinning reserve capacity. At low renewable penetration levels, this is easily accomplished since the net load demand is high and many load-follower units are online. At high renewable penetration levels, using demand response to meet spinning reserve reduces the amount of load-following units required to be online. Therefore, when unexpected drops in renewable generation cause short-term but large increases in the net load demand, this must be met by peakers that will have to start-up and ramp quickly rather than load-following units that were already online and producing power. A similar principle occurs for ramping down in the event of unexpected renewable generation spikes. This contributes to an increase in the balance generator fleet ramp rates.

The use of demand response also affects the number of balance generator start-up events, as presented in Figure 146:

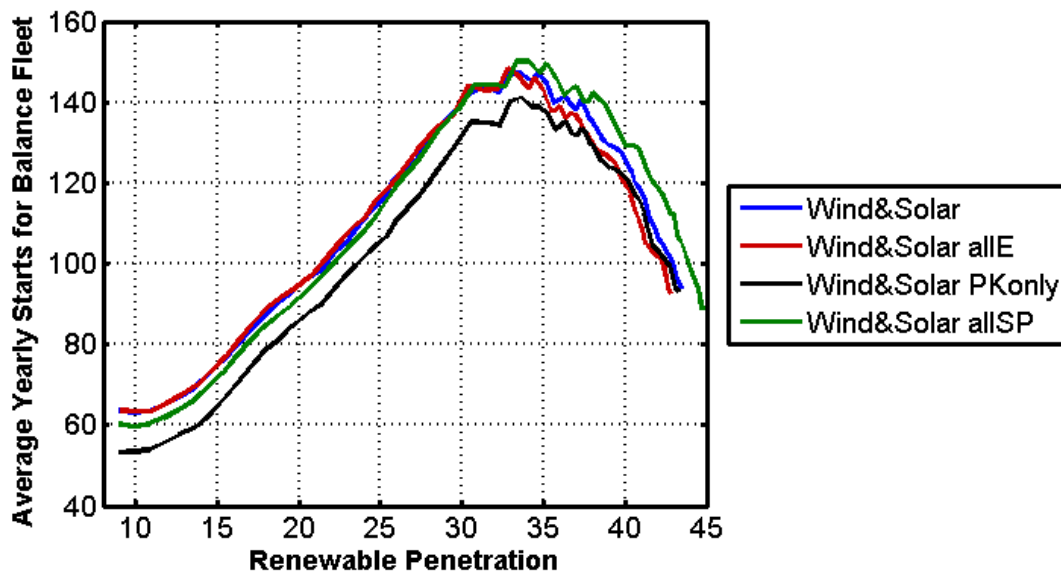


Figure 146 - Average Yearly Start-Up Events per Balance Generator for Different DR Application Strategies

The behavior of the average number of start-up events per balance generator reflects the behavior shown for that of the generator ramp rates, and is motivated by the same factors at high renewable penetration levels. Using demand response to provide spinning reserve requires more peakers to start up in order to meet transients in the load demand since a lower amount of load-followers are online. Using DR for peaker support prevents many of these units from being required, decreasing start up events. Using DR to reduce energy consumption reduces peak load magnitudes, reducing the amount of generators that need to come online to meet them.

5.1.3.3.1.3. Behavior of the Grid CO₂ Emissions

Demand response also has the ability to further reduce the carbon dioxide emissions beyond what renewables alone can achieve. Figure 147 presents the resulting CO₂ reductions from all three bounding scenarios as compared to the base case without DR. The all energy case reduces the most CO₂ because it reduces the energy of the load demand by the largest amount. The peaker support case also reduces emissions between one half and one percent more than the base

case. Lastly, the all spinning reserve case reduces emissions by improving the load-following fleet efficiency and further enabling the uptake of renewables but is limited in its effectiveness because it does not actually reduce generation.

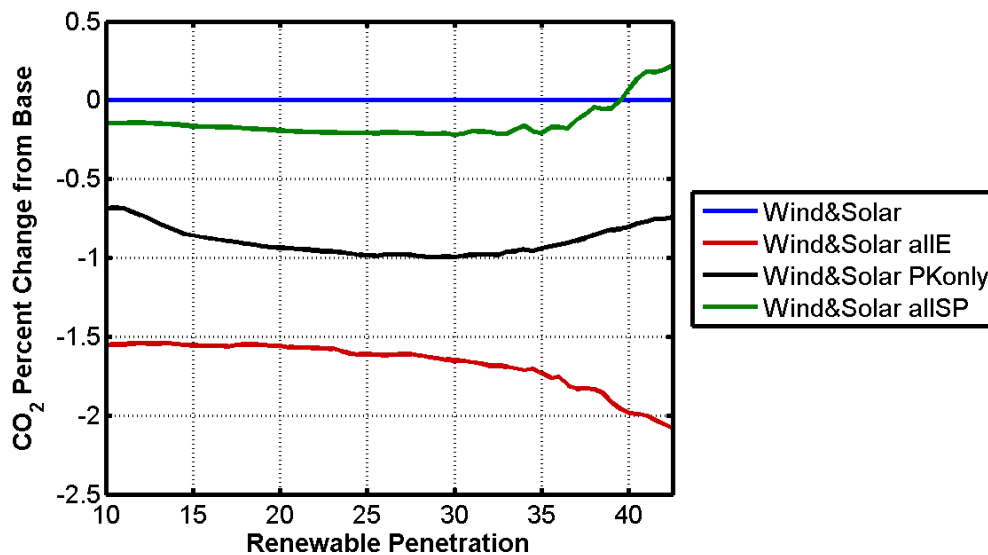


Figure 147 - Effects of Demand Response on CO₂ Emissions as a Percent Change

5.1.3.3.2 Sensitivity of Economic Behavior

5.1.3.3.2.1. Behavior of the Levelized Cost of Electricity

The levelized cost of electricity for each strategy is presented in Figure 148 as a percent change from the baseline case without demand response. Initially, all DR strategies are more cost competitive than the base case. The all energy case crosses around 33% penetration and peaker support crosses around 39.5% penetration. This crossing point signifies, particularly for the all energy case, when its near base load behavior actually reduces the potential renewable penetration. DR should behave differently at different renewable penetrations to maximize its economic benefit. Because the grid system can initially support greater base load capacity and can benefit from lower generation requirements the all energy case is the most competitive; however as the grid's ability to support additional base load while implementing renewables

decreases so does the value of the all energy case. The peaker support value rises once additions of solar and wind power intensify the need for peakers and is able to maintain value much longer and only turns down because of the firming effect from the curtailment of excess generation. The DR strategy providing spinning reserve starts with lower value than the other resources because of the relative abundance of generation that can be turned down to provide spinning reserve and regulation. As the penetration increases and the availability of dispatchable generation decreases the value of DR providing spinning reserve increases significantly.

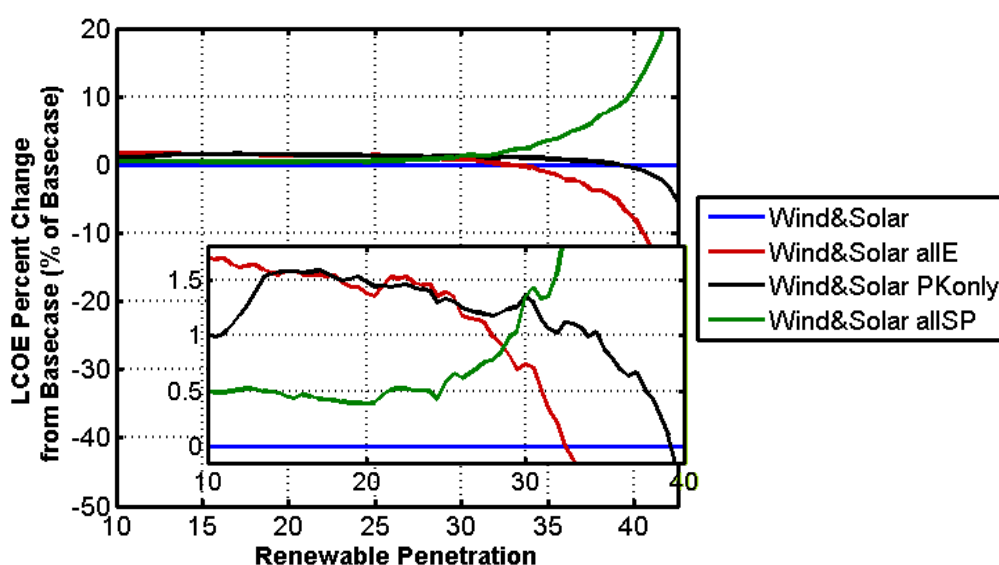


Figure 148: Effects of Demand Response on Levelized Cost of Electricity

Renewable penetration is calculated based on the sum of the renewable power generated divided by the retail sales of electricity. Since demand response does not contribute to the retail sales of electricity, but rather reduces the demand, the renewable penetration will increase with the inclusion of demand response technologies.

This following set of figures shows the value of DR that could be paid to the customer in a per energy fee (\$/MWh) or a capacity-based fee (\$/MW) (Figure 149 and Figure 150). DR Programs

can include capacity payments, or energy payments so these figures present the value of integrating DR. Just as in the previous figure, the value of DR tapers off at sufficiently high penetrations, where significant curtailment occurs; however, it is interesting to note that the \$/MWh for peaker support is more than the all-energy case despite the fact that the all-energy case provides more significant advantage (as shown in the previous figure). The spinning reserve case for the top figure is included with levelization coming from the energy provided for SP (though it may not be called on). The bottom figure uses the installed lighting and fan capacity as its denominator.

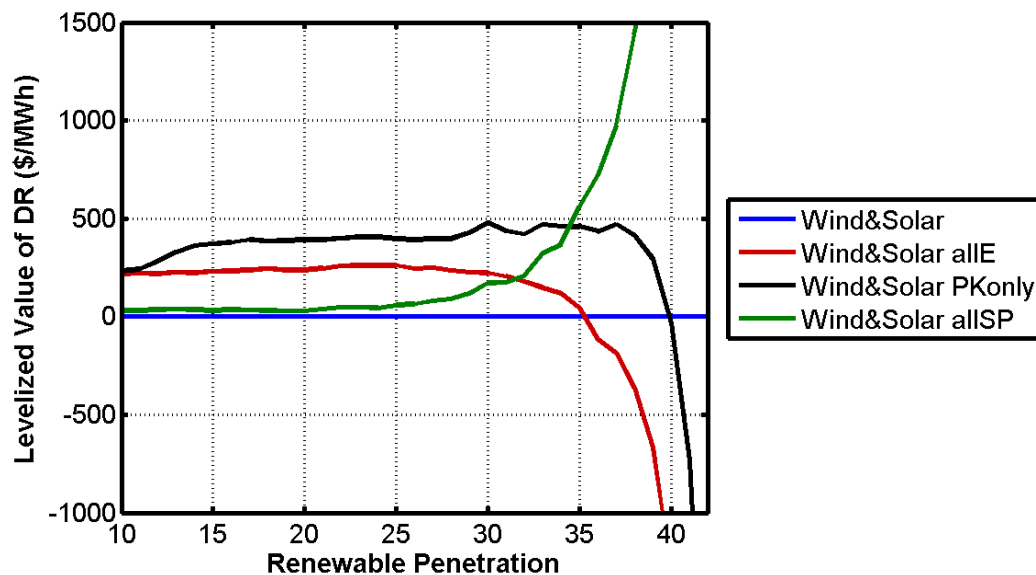


Figure 149 - Value of DR Distributed Over Energy Provided

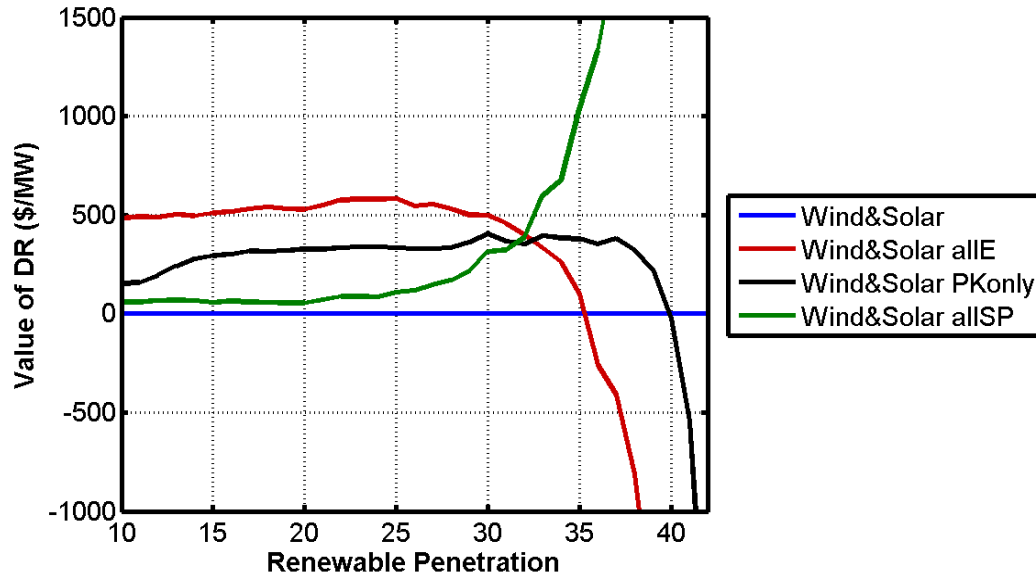


Figure 150 - Value of DR Distributed Over Installed Power Capacity

Interestingly, the peaker support value for Figure 149 is greater than all energy and spinning reserve, while the value for all energy is the highest for the capacity payment in Figure 150. This means that the value of providing energy for peaker support is greater than that of all energy; however, all energy provides more energy and is more valuable from a capacity point of view. For both figures, the value of spinning reserve starts below that of the other scenarios and picks up as the renewable penetration increases. This does not signify that spinning reserve is less valuable than providing energy but that the value of demand response to provide spinning reserve is initially less valuable than demand response to provide energy. Using demand response to reduce the load on the system also removes the fuel cost and variable operation and maintenance cost of the generation that is displaced. Investments for generation capacity once made are available for use the entire year so while reducing the load on a given generator will reduce its economic competitiveness, it will also reduce the system-wide LCOE thus resulting in the benefit seen above.

5.1.3.4. Summary and Conclusions

5.1.3.4.1. Summary

A study was conducted to characterize the effectiveness of implementing demand response in different applications in the context of supporting increased variable renewable generation on the electric grid.

A 50/50 wind and solar capacity mix was used to represent renewable deployment and was incrementally increased up to a combined capacity of 300 GW, with base load generation levels fixed at year 2005 levels. A high impact of demand response measures was assumed. At each renewable capacity increment, the impacts on the required installed capacity to reach a given renewable penetration level, grid capacity factor, balance fleet ramp rates and start-up events, and the levelized cost of electricity using three bounding applications of demand response were evaluated. The outcomes of the study are as follows.

5.1.3.4.2. Technical Conclusions

Demand response was applied in different operating strategies to examine the effects of each application on the design and operation of electric grid resources. Some of the key points are as follows:

- **The preferred strategy for using demand response will change with renewable penetration and depends on what metric is desired to be improved.**
 - o Applying DR for energy reduction enhances renewable penetration at low penetration levels, but degrades it at high renewable penetration levels. This strategy reduces CO₂ emissions by the largest extent at all penetration levels

- o Applying DR for peaker support decreases balance generator ramp rates and startup events to the largest extent by reducing reliance on highly dynamic generators.
- o Applying DR for meeting spinning reserve enhances the renewable penetration significantly at high penetration levels and improves the grid capacity factor by the largest amount. This strategy, however, slightly increases ramp rates, start-up events and offers the least reduction in CO₂ emissions.

5.1.3.4.3. Economic Conclusions

- **Different operating strategies should be employed for DR as the renewable penetration changes to maximize economic value.**
 - o At low renewable penetrations DR should focus on reducing as much energy as possible
 - o At medium renewable penetrations DR to support peaker operation becomes the most cost competitive strategy (briefly)
 - o At high renewable penetrations DR should focus on providing spinning reserve

Demand response can increase the apparent renewable penetration by enabling greater renewable generation while lowering the retail sales of electricity since it reduces the demand on-site.

A unique technique to determine the value of DR based on its impact on the grid is presented (results are shown based on installed DR capacity (\$/MW) and energy provided (\$/MWh))

Overall, there are many aspects to consider when utilizing demand response to support the integration of renewable resources into the electric grid. Careful selection of appropriate sizing

and operating modes of these technologies must take place in order to maximize the benefit to the grid in the context of supporting variable renewable integration.

5.2. Water Supply Sector

Currently, certain sections of the text in this section are also described in publications that have been currently submitted to refereed journals as follows:

- **Tarroja, B.**, AghaKouchak, A., Samuelson, S., Sobhani, R., Feldman, D., Jiang, C.S., “*Evaluating Options to Stabilize the Water-Electricity Nexus in California: Part 1 – Stabilizing Major Reservoir Levels*”, Science of the Total Environment, 2014. **Submitted as of March 2014**

5.2.1. Water Reservoir Stabilization Measures

5.2.1.1. Literature Review

Concerns over climate effects on water availability combined with increasing demands in various regions are driving interest in diversifying the water supply portfolio. Many regions in the world are expected to face decreased water availability due to the impacts of climate change on regional hydrology and weather patterns [239-250]. A number of studies predicted a warmer and drier climate with less snow pack in future in southwestern United States [246, 251] that could affect the both water availability and energy production [252]. Coupled with population growth and projected increases in demand in many regions, the need for more prudent water management strategies and alternative options for usable water supply has been identified. Many alternative options for water supply are currently available. The accessibility of these options varies significantly by region, however, reliance on the historical paradigm of precipitation-based surface and groundwater supplies may not be enough to meet increasing demands.

Water conservation is one option that is encouraged in many sectors and regions. Conservation is considered as the most direct and immediate method for stabilizing the water supply. For

example, regions such as California have managed to maintain per-capita water usage at steady levels through improvements in urban and agriculture water use efficiency measures [9, 69], offsetting the increase due to population growth. Certain studies have estimated that water conservation measures may be enough to negate the impacts of climate change in particular regions [253]. It has also demonstrated beneficial economic impacts by reducing the cost of water and increasing the value of related commodities such as food [254, 255].

Desalination is another option that has been implemented or is being considered as part of the water supply portfolio to combat water shortages in arid regions. As of 2011, a worldwide capacity of about 72 Mm³/d has been installed, with the largest share of this capacity being located in the Persian Gulf countries in the Middle East region for seawater desalination, and the second largest total capacity in North America, mostly focused on brackish water desalination [256, 257]. Middle Eastern regions have historically relied on thermal desalination, whereas new plants in North America and Australia have relied on membrane technology for large scale operations. For example, a membrane desalination plant was installed in Sydney, Australia as a contingency measure after the effects of the Millennium Drought which impacted the region from 1995 to 2010, with the capability to provide up to 15% of the city's water supply [222]. High energy demand is the biggest challenge in desalination installation and operation. Many research efforts in this area focus on reducing the energy and greenhouse gas impacts of this measure [106, 258] or comparing it with other options [259, 260]. The use of desalination, however, is limited to coastal regions with access to seawater or inland regions with access to large brackish groundwater reservoirs.

Besides conventional resources, reclaimed wastewater effluent is another alternative resource option to help secure water supplies. Approximately 12 billion gallons (45.4 Mm³) of municipal wastewater effluent is discharged each day to an ocean or estuary out of the 32 billion gallons per day (121.1 Mm³/d) discharged in the United States. Reusing these coastal discharges would directly augment available water resources (equivalent to 6 percent of the estimated total U.S. water use or 27 percent of public supply) [261]. About 5-6% of municipal wastewater effluent in the U.S. is reclaimed and beneficially reused. It is projected that water reuse level will increase from 1.92 BGD (7.27 Mm³/d) in 2008 to 2.7 BGD (10.22 Mm³/d) by 2015. In some countries with scarce water resources (e.g. Singapore) up to 30% of the wastewater is reused. In 2009, State of California reused 218 BG (825.2 Mm³) reclaimed water [136]. Among this volume, 36.5% was used for agricultural irrigation, 11.9% for groundwater recharge, 9.7% for industrial reuse, 11.7% for wetlands, and 12.6% for public access irrigation.

Overall, however, there have been few studies which have holistically compared different available options for stabilizing reservoir levels on common criteria under different hydrologic conditions. Therefore, this analysis is aimed at determining the following for this system:

- The ability of individual options to contribute towards stabilizing the water supply
- The scale (capacity) of individual and mixed option portfolios required to stabilize surface reservoir levels under baseline and climate change augment hydrological conditions.

With a sense of scale for how much of these options would be required, the strength of the interactions with the energy sector can then be determined. This is the focus of Section 6.2.

The system of the state of California is used. This region was chosen due to its diversity of climate regions and water demand types, high population, and access to a diverse array of water options.

5.2.1.2. Approach

5.2.1.2.1. Metrics of Analysis

There are two primary metrics that will be used to evaluate the performance of each individual option or mix of options:

Net Reservoir Fill Change: This represents the difference between the fill level of a reservoir or aggregate group of reservoirs at the beginning and the end of the 10-year analysis time period. This metric is used to determine the extent to which implementing an option of a given capacity is able to stabilize reservoir levels. If this metric is positive, this indicates that the reservoirs are able to maintain their levels and are considered stable, whereas a negative value indicates an overall decrease in reservoir levels. The stabilizing capacity of a given option is the minimum capacity required to restore the statewide aggregate net reservoir fill level change to a positive number.

Groundwater Demand Change: This refers to the change in the amount of water that the system needs to draw from groundwater reservoirs, as a percentage of the statewide groundwater demand. Water allocations are freed up for recharging groundwater when the demand on a given reservoir is reduced below its minimum demand due to the implementation of water supply stabilizing options. While this study does not model the groundwater reservoirs directly, this metric has implications for stabilizing groundwater withdrawal and reducing overdraft.

5.2.1.2.2. Analysis Approach

5.2.1.2.2.1. Inflow and Demand Conditions

This study evaluates the scale of options needed to stabilize reservoir levels under two distinct conditions: baseline and climate-change augmented. These are described as follows:

The **baseline conditions (BAS)** are represented by the 2000-2010 time period. Reservoir inflow data for all of the included reservoirs was obtained from the California Data Exchange Center (CDEC) [196] and historical reports for the operation of the State Water Project (SWP) [43], with a daily resolution. The demand vectors for each reservoir are also daily resolved, and are unchanged from the values used in the model verification.

The **climate change augment conditions (CCHa)** are chosen to represent the 2040-2050 time period. Reservoir inflows were modified by obtaining spatially-resolved runoff data from four different climate models (ccsm3, cnrm, gfdl, and pcm1) from the CalAdapt climate database [262]. The IPCC Climate Scenario A2: “High Emissions” case was utilized for the runoff data. This case represents a “worst case” scenario of high greenhouse gas emissions and highly exacerbated effects of climate change. This was chosen to set the climate change augment conditions as a bounding worst case. The difference between the runoff data for the 2000-2010 and 2040-2050 time periods was calculated and applied as a modification to the baseline reservoir inflow data. Due to variability in climate model predictions, an average across all four climate models at each time step was used.

In addition to the inflow data, the reservoir demand data was also changed under the CCHa case. Projections for the change in the average yearly urban and agriculture water demand between historical trends and the 2043-2050 time period for the whole state was provided by the

California Department of Water Resources [48]. The “Current Trends” scenario was utilized. While the future period refers to 2043-2050 instead of the 2040-2050, the use of an average yearly demand still allows it to be suitable for use in our analysis. These demand changes were distributed spatially in hydrologic regions by urban water demand and irrigated agriculture demand distributions [48].

5.2.1.2.2.2. Option Capacity Spanning

A spanning study was performed by increasing the installed capacity of each option until either its maximum capacity potential is reached, or until a given capacity is able to restore the CA statewide reservoir fill condition to a non-negative number, whichever comes first. This was carried out for each of the options discussed in Section 2.3. Option capacity deployment perturbs the reservoir system by reducing the demand placed on the appropriate reservoirs. It is important to note that water produced by any of the measures is **NOT** placed in the major surface reservoirs. Rather, by displacing reservoir demands, the reservoirs are allowed to store more of their respective inflows, increasing reservoir levels.

The spatial distribution of urban water conservation was set according to the distribution of urban water demand by hydrologic region [48]. For water reuse, the spatial distribution is set by that of wastewater treatment plant capacity using the locations of wastewater treatment plants. For thermal desalination with waste heat, capacity is distributed along the three coastal regions according to calculated waste heat potential, while for all other desalination measures, it is set according to the urban population distribution along the coastal regions. In addition, a case which biases membrane desalination capacity more so towards the South Coast region is also included.

Based on the results of the individual option capacity spanning, hybrid mixes of available options are also developed. These cases are explained and presented in the results section.

5.2.1.3. Results

5.2.1.3.1. No-Option Reservoir Fill Levels

To establish a reference for the reservoir system, the reservoir fill profiles for the 10-year period for three hydrological conditions are presented in Figure 151. In addition to the BAS and CCHa cases described previously, and additional case (CCHa-ND) shows the reservoir fill profiles with climate-change augmented inflows but no demand change, to highlight the effect of climate change alone.

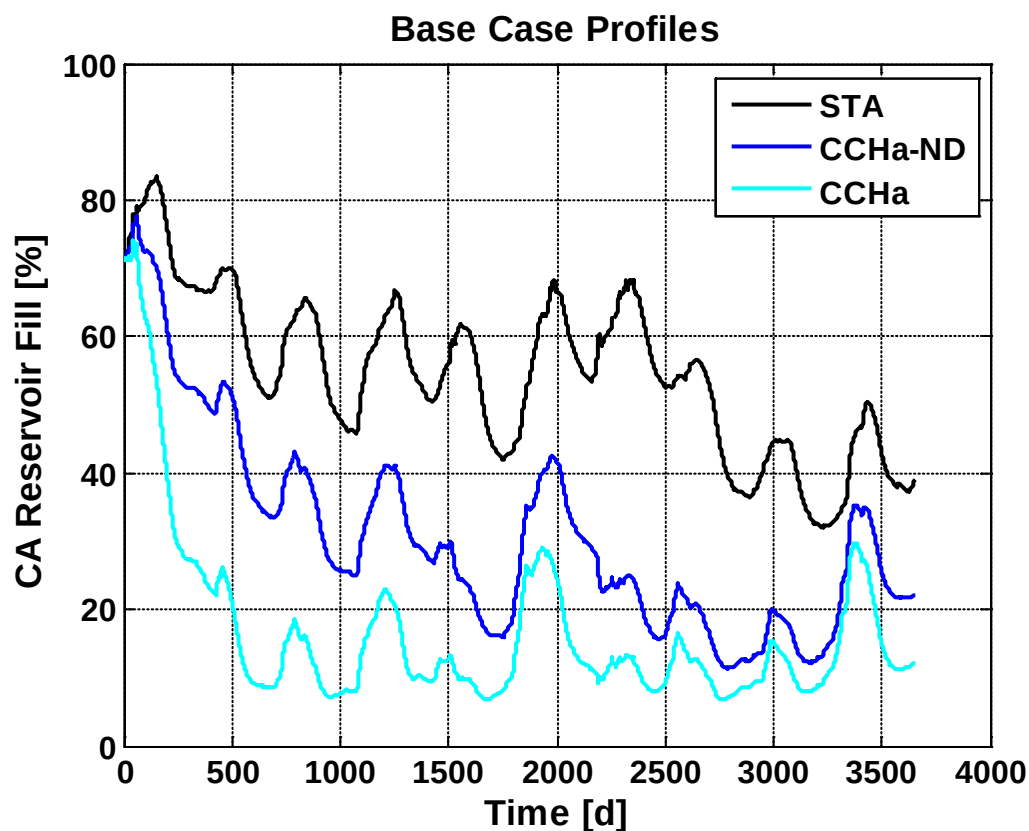


Figure 151 - No Option Reservoir Fill Profiles

For baseline inflow and demand conditions, the reservoir levels gradually decrease over the 10-year period. The overcommitting of available water resources combined with drought periods has caused reservoir levels to decrease. Lake Mead is particularly at risk due to overcommitting. The aggregate reservoir fill level drops from about 71% to 38%, for a net change of -33%.

For the case with climate change augmented inflows but no demand change, the prediction of reduced precipitation in the northern and easternmost regions of California which supplies the Sacramento Delta causes further reductions in the statewide reservoir fill condition. This is especially pronounced during the latter end of the time period, where the aggregate reservoir levels drop below 20%. The net change in statewide reservoir fill condition is exacerbated to -49%.

When climate change augmented inflows and demand increases are considered, the situation worsens. Reservoir levels drop to very low levels almost instantly, and remain low for the entirety of the time period, with a net reservoir fill change of -59.8%. It is important to highlight that the additive effects of the increase in demand and climate change affected inflows that potentially cause a water crisis in the state.

5.2.1.3.2. Securing Capacities – Individual Options

For individual options, the progression of the net reservoir fill level change in the statewide reservoir fill condition is presented in Figure 152 for baseline conditions:

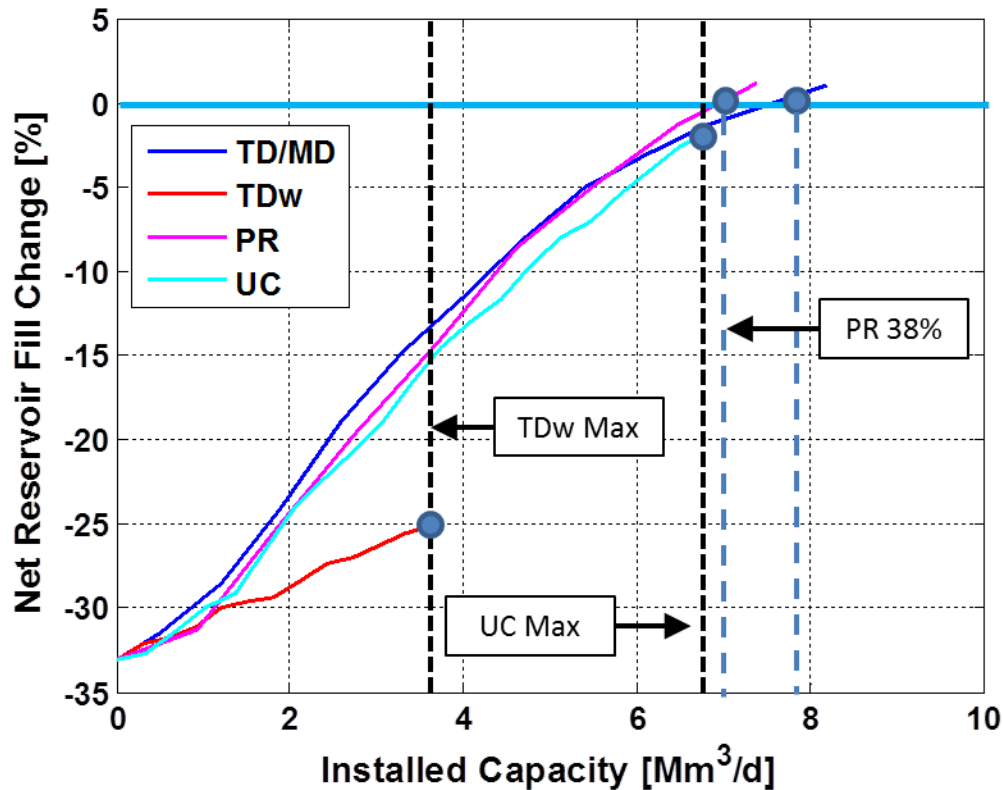


Figure 152 - Net Reservoir Fill Change vs. Individual Option Installed Capacity – Baseline Conditions

Under these conditions, most of the individual options are able to stabilize or nearly stabilize surface reservoir levels. The exception is thermal desalination with waste heat which does not have enough potential in California to secure reservoir levels. Due to the shutdown of the San Onofre Nuclear Power Plant, the majority of capacity is due to the waste heat from the Diablo Canyon Nuclear Power Plant. This measure also increases net reservoir fill levels at a lower rate than other technologies due to its spatial distribution, since most of its capacity is located in the central coast, which has less leverage in the system compared to the south coast region.

The spatial distribution of all of the other measures is highly concentrated in Southern California, which is a point of leverage in the system. Southern California imports most of its water through a canal system, therefore its local reservoirs tend to be supplied by other reservoirs preceding it

in the system. Therefore, a gallon of water saved in southern California does not only increase the reservoir fill levels of local reservoirs, but also for all of the reservoirs that supply them. This allows it to have a multiplicative effect on raising the statewide reservoir fill condition.

The use of urban water conservation alone with the potential used in this analysis is not quite sufficient to stabilize statewide reservoir levels, although it does get fairly close to doing so. At 100% of the potential considered here, the statewide reservoir fill condition is raised from -33% to -1.712%. Additional conservation measures that were not taken into account may be enough to stabilize reservoir levels under baseline hydrological conditions.

The remaining options of wastewater purification / reuse and the other types of desalination considered in this study are able to stabilize reservoir levels under these conditions. Water reuse is able to do so while utilizing only 38% of its potential capacity. The difference between the progression for wastewater purification / reuse and that for desalination is due to slight differences in their spatial distribution, but more importantly, differences in their operating profile. Water reuse follows the profile of the reservoir demand and works to reduce it, while desalination is steady state and does not dispatch. At lower reservoir levels, desalination is more effective by providing water during periods of low and high demand, whereas at higher reservoir levels, water reuse reduces peak demands and becomes more effective.

Profiles of the statewide aggregate reservoir fill condition for wastewater purification / reuse and for thermal and membrane desalination are presented in Figure 153 and Figure 154, respectively. These profiles show that when the net reservoir fill levels are raised to their initial conditions, the reservoir levels remain high during the entire analysis period. Additionally, the incremental increase in average reservoir levels is fairly linear for an incremental increase in option capacity.

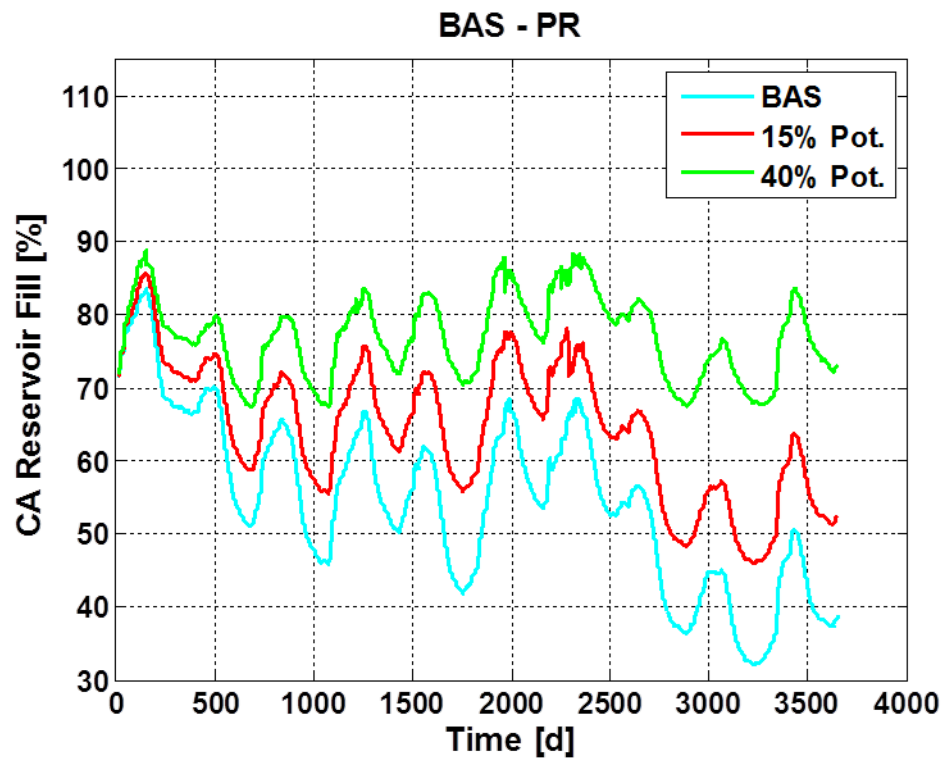


Figure 153 - Reservoir Fill Profiles for Wastewater Purification / Reuse under Baseline Conditions

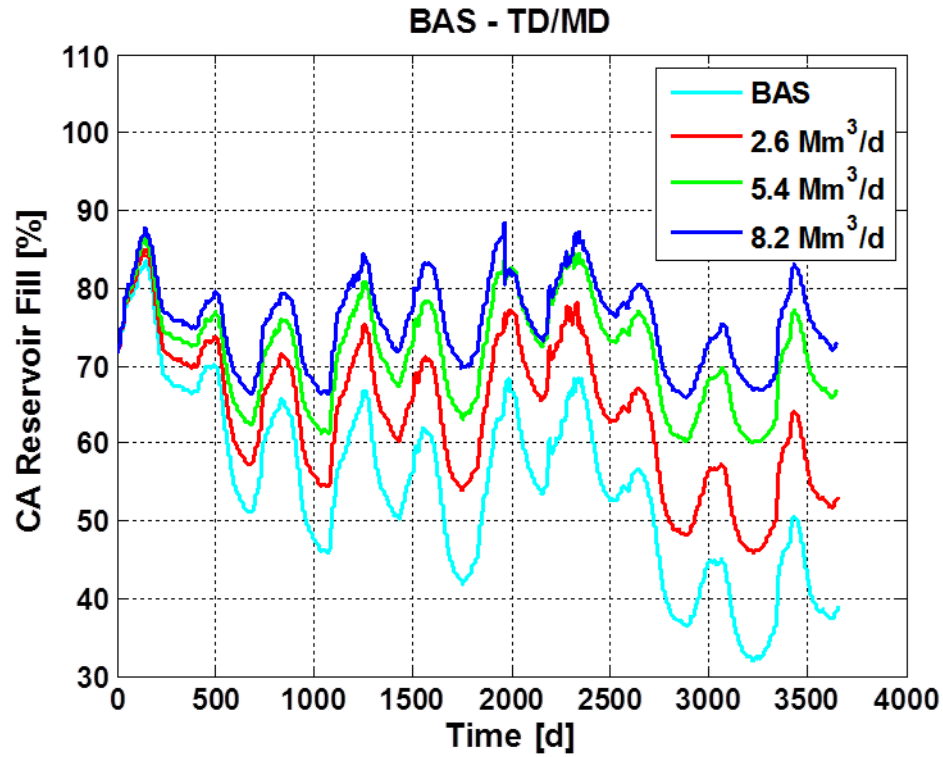


Figure 154 - Reservoir Fill Profiles for Thermal / Membrane Desalination under Baseline Conditions

For individual options, the progression of the net reservoir fill level change in the statewide reservoir fill condition is presented in Figure 155 for climate change augmented conditions:

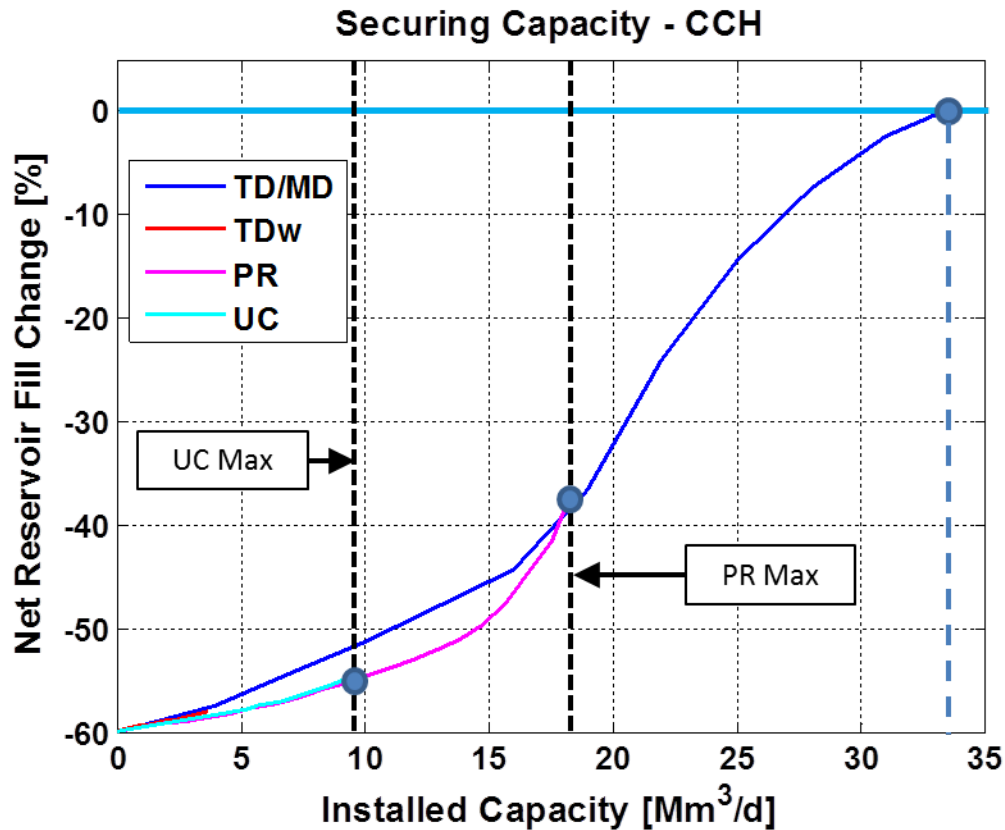


Figure 155 - Net Reservoir Fill Change vs. Individual Option Installed Capacity – Climate Change Augmented Conditions

Under climate change, the situation changes considerably. Combination of reduced inflow **and** increased urban demand significantly reduces reservoir levels. Over the 10-year period considered, the net reservoir fill change is -59.8%. This causes the scale of technologies required to stabilize reservoir levels to be significantly increased.

Of the individual options considered, only desalination is able to eventually stabilize reservoir levels. This makes sense since direct thermal desalination and membrane desalination is the only option that does not have a hard, technical limit on the scaling up of its installed capacity. However, relying solely on this measure requires an extreme amount of capacity. For context, the total amount of desalination capacity in the world is around 78 Mm³/d. Urban water

conservation is limited by the demand requirements, and water reuse is limited by the amount of wastewater effluent available, which is in turn limited by demand requirements.

Under these conditions, the shape of the curve to reach stabilizing capacities has two distinct regions, evident in the desalination curve and somewhat in the wastewater purification/reuse curve. At the lowest reservoir fill levels, the incremental increase in the net reservoir fill change due to technology deployment is lower compared to that at higher reservoir fill levels. This occurs since at low reservoir levels, small displacements of reservoir demand does not significantly increase reservoir levels, since the demand is still so large such that most or all of the inflow introduced to the reservoir must be immediately passed through to satisfy it.

Therefore, an incremental water savings does not allow as much inflow to be stored as in higher reservoir levels. This trend starts to tailor off as reservoir levels become full, and passing through of inflow occurs to prevent overfilling the reservoir.

In this context, urban water conservation and thermal desalination with waste heat are unable to increase reservoir levels to any significant amount. The net reservoir fill change at 100% capacity for both measures is -54.72% and -57.98% respectively, up from -59.81%. Water reuse, which has a much larger potential capacity, is able to raise the net reservoir fill change to -36.36% if 100% of the capacity is utilized. This option is able to reach the point where proportionally more of the reservoir inflow is able to be stored.

Profiles of the statewide aggregate reservoir fill condition for wastewater purification / reuse and for thermal and membrane desalination are presented in Figure 156 and Figure 157, respectively:

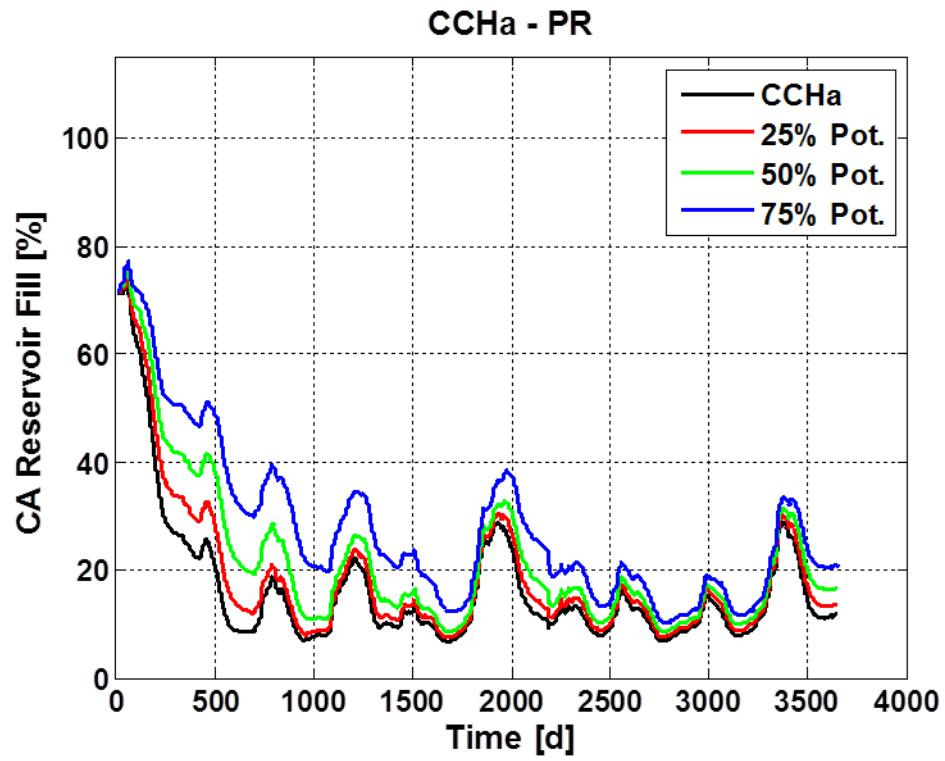


Figure 156 - Reservoir Fill Profiles for Water Reuse under Climate Change Augment Conditions

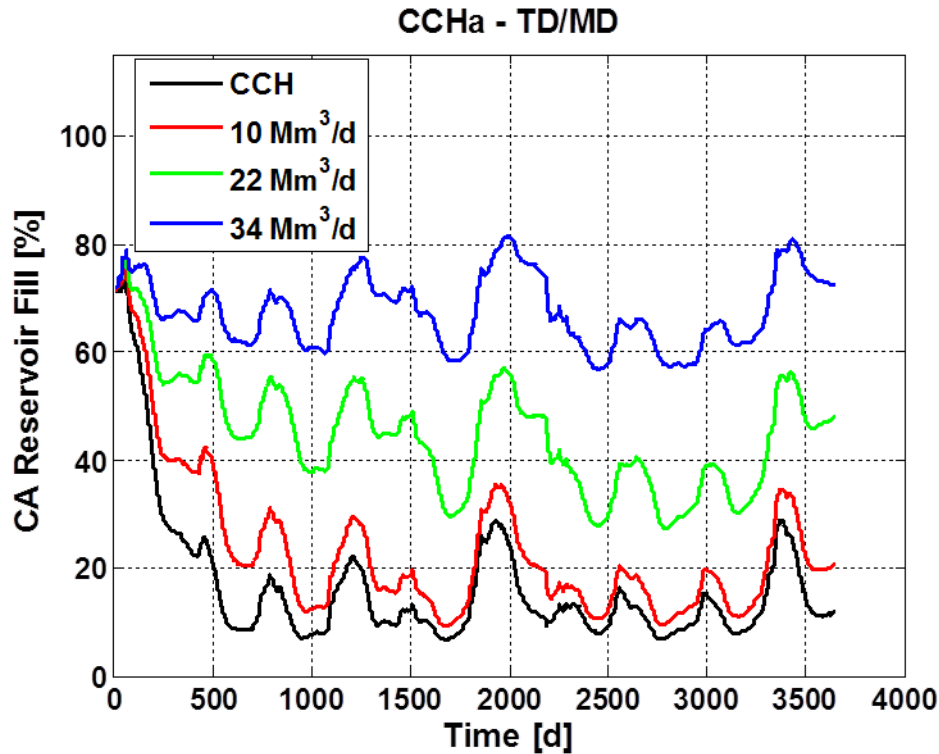


Figure 157 - Reservoir Fill Profiles for Thermal / Membrane Desalination under Climate Change Augment Conditions

In contrast to the profiles displayed for the baseline conditions, incremental increases in water stabilizing option capacity does not increase the reservoir fill levels to a significant extent when the reservoir fill levels are already low. The profiles for implementing water reuse only show small increases in overall reservoir levels, with the 25% and 50% potential curves showing almost no increase during certain time periods. This is consistent with the notion explained previously that when the demand is high and inflow is low, most if not all of the inflow that is introduced to the reservoir must immediately be passed through to meet the demand and very little to no inflow is actually stored to increase reservoir fill levels. This is also evident for the profiles using desalination, where 10 Mm³/d barely increases reservoir levels, but 22 Mm³/d noticeably increases reservoir levels.

5.2.1.3.3. Securing Capacities – Hybrid Cases

Based on the behavior of individual options, a number of hybrid scenarios were constructed to stabilize reservoir levels. These scenarios, as well as either the securing capacities for each individual option is presented in Table 53 for baseline conditions and in Table 54 for climate change augment conditions. If an individual option is unable to stabilize reservoir levels by itself, its maximum capacity is listed. The MD (SC) case is an additional case using only membrane desalination, but instead of spatially distributing along the coast according to urban population, it is more heavily biased to have 80% of its capacity in the South Coast region (compared to 64.8% in the MD case).

Table 53- Securing or Maximum Capacities for Individual (Orange) and Hybrid (Blue) Option Cases in Mm³/d – Baseline Conditions

Designation	<u>UC</u>	<u>TDw</u>	<u>TD</u>	<u>MD</u>	<u>PR</u>
No Options	0.00	0.00	0.00	0.00	0.00
TDw	0.00	3.63 (100%)	0.00	0.00	0.00
TD	0.00	0.00	7.60	0.00	0.00
MD	0.00	0.00	0.00	7.60	0.00
MD (SC)	0.00	0.00	0.00	7.10	0.00
UC	6.83 (100%)	0.00	0.00	0.00	0.00
PR	0.00	0.00	0.00	0.00	7.00 (38%)
UC/PR	6.83 (100%)	0.00	0.00	0.00	0.55 (3%)
MD/UC	6.83 (100%)	0.00	0.00	0.65	0.00

Table 54 - Securing or Maximum Capacities for Individual (Orange) and Hybrid (Blue) Option Cases in Mm³/d – Climate Change Augment Conditions

Designation	UC	TDw	TD	MD	PR
No Options	0.00	0.00	0.00	0.00	0.00
TDw	0.00	3.63 (100%)	0.00	0.00	0.00
TD	0.00	0.00	34.00	0.00	0.00
MD	0.00	0.00	0.00	34.00	0.00
MD (SC)	0.00	0.00	0.00	30.50	0.00
UC	9.50 (100%)	0.00	0.00	0.00	0.00
PR	0.00	0.00	0.00	0.00	18.44 (100%)
UC/PR	9.50 (100%)	0.00	0.00	0.00	18.44 (100%)
MD/UC	9.50 (100%)	0.00	0.00	19.50	0.00
MD/PR	0.00	0.00	0.00	7.20	18.44 (100%)
P1	9.50 (100%)	0.00	0.00	7.40	18.44 (100%)
P2	9.50 (100%)	3.63 (100%)	0.00	5.00	18.44 (100%)

For each individual and hybrid scenario, the effect on the California statewide fill condition, as well as on regional groups of reservoirs is presented in Table 55 for baseline conditions and in Table 56 for climate change augment conditions. The reservoirs that are included in the model are grouped according to their location by hydrologic region to give a sense of regional reservoir level changes and management capabilities. South Coast reservoirs include Pyramid Lake, Castaic Lake, and the CA Effective Lake Mead, Tulare Lake Reservoirs include Millerton Lake and Pine Flat, San Joaquin River reservoirs include San Luis, Don Pedro, New Melones, and Exchequer, while Sacramento River reservoirs include Folsom Lake, Lake Shasta, Trinity Lake, and Lake Oroville. The cases which are unable to stabilize reservoir levels are highlighted in red, while those which are able to accomplish this goal are highlighted in green.

Table 55 - Net Reservoir Fill Level Changes for Statewide Aggregate and Regional Reservoir Groups under Baseline Conditions

<u>Designation</u>	<u>CA Total (%)</u>	<u>SC (%)</u>	<u>TL (%)</u>	<u>SJ (%)</u>	<u>SR (%)</u>
No Options	-33.000	-57.798	-5.461	-15.779	-23.403
TDw	-24.970	-52.809	1.623	-5.173	-13.928
TD	0.069	3.269	13.686	2.612	-6.545
MD	0.069	3.269	13.686	2.612	-6.545
MD (SC)	0.031	4.857	13.757	1.595	-7.562
UC	-1.712	-4.122	19.118	5.192	-6.588
PR	0.210	1.720	13.009	6.274	-6.924
UC/PR	0.184	-0.633	19.454	6.458	-5.645
MD/UC	0.092	-0.290	17.516	6.082	-5.739

Table 56 - Net Reservoir Fill Level Changes for Statewide Aggregate and Regional Reservoir Groups under Climate Change Augment Conditions

<u>Designation</u>	<u>CA Total (%)</u>	<u>SC</u>	<u>TL</u>	<u>SJ</u>	<u>SR</u>
No Options	-59.819	-64.787	-34.556	-58.360	-59.203
TDw	-57.982	-64.343	-33.159	-56.150	-56.176
TD	0.570	10.862	12.008	-4.162	-8.009
MD	0.570	10.862	12.008	-4.162	-8.009
MD (SC)	0.119	13.809	19.656	-8.363	-10.434
UC	-54.725	-62.662	-28.345	-53.494	-51.179
PR	-36.364	-52.950	-20.949	-13.829	-36.738
UC/PR	-36.535	-59.233	7.695	-14.733	-34.201
MD/UC	0.390	5.965	21.750	-1.624	-6.617
MD/PR	0.062	5.404	19.713	2.294	-9.258
P1	0.059	2.188	25.301	2.313	-6.843
P2	0.046	-2.104	24.930	4.971	-4.330

For standard conditions, the hybrid cases which stabilize reservoir levels did not include a combined PR/MD case. This was unnecessary since water reuse stabilizes reservoir levels alone. The regional effects of both hybrid cases are only slightly different, but show the same trend of being able to stabilize all regions except the northernmost part of California. It is important to

note that since historical management practices are embedded in these results, this implies that changes in water management in addition to the freeing up of water allocations assumed in this model are required to stabilize the northernmost region of California.

For climate change augment conditions, many more hybrid cases were constructed since only desalination was able to scale up to the degree required to stabilize reservoir levels. Desalination, however, can have significant energy implications as will be explained in the Water-Electricity coupling study, and other measures may be implemented to reduce the required capacity of desalination needed. This informed the construction of the other hybrid cases.

The UC/PR case is unable to stabilize reservoir levels, despite using 100% of the urban water conservation capacity and wastewater purification/reuse capacity considered in this study. This occurs due to the fact that these two measures can be parasitic to each other to some extent.

Urban water conservation reduces the wastewater effluent available from wastewater treatment plants, which reduces the amount of water available for reuse, since it is tied to the water demand. Therefore, not all of the purification/reuse potential capacity can be effectively utilized under aggressive urban water conservation. The conserved water compensates for this reduced purification/reuse capacity, however, but the total effect on reservoir fill levels is no better than the case where 100% of the purification/reuse capacity is effectively utilized (PR). On a regional level, the PR and UC/PR cases differ due to the spatial distribution of each measure.

All of the other hybrid cases, therefore, include some amount of desalination. This highlights the role of desalination in securing the water supply for this region under worst case climate change augment conditions. The P1 and P2 cases make extensive use of conservation and purification/reuse, complemented by between 7.4 to 8.6 Mm³/d of desalination, depending on

desalination type. Regionally, most of these cases stabilize or nearly stabilize all of California with the exception of the northernmost Sacramento River region, which is drastically hit by reductions in inflow due to climate change.

A final important aspect to note is the sensitivity to the spatial distribution of installing a given capacity of an option. In both baseline and climate change augment conditions, the MD (SC) case is able to stabilize surface reservoir levels with a lower installed desalination capacity compared to the MD case. This further demonstrates the importance of installing technologies in points of leverage on a water system for maximum effectiveness. In this case, southern California is the major point of leverage since changes in its demand can affect every reservoir in the state.

5.2.1.3.4. Implications for Reducing Groundwater Demand

In this model, water allocations are freed up for recharging groundwater when the demand on a given reservoir is reduced below its minimum demand due to the implementation of water supply stabilizing options. It is important to remember, however, that the priority of freeing up water allocations goes to stabilizing surface reservoir levels in this study. In practice, freed allocations may be shared between replenishing groundwater and stabilizing surface reservoir levels. The total water allocation available for societal use, however, would not change. The changes in groundwater demands due to these allocations for each case is presented in Figure 158 for baseline conditions and in Figure 159 for climate change augment conditions.

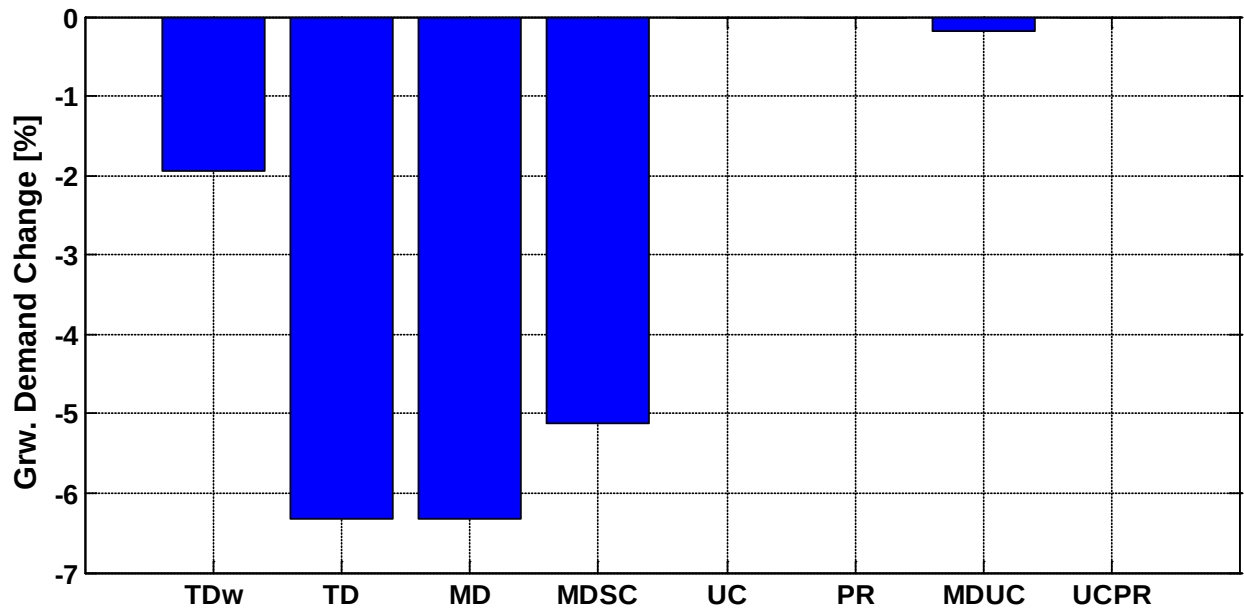


Figure 158 - Change in Groundwater Demand for Baseline Condition Cases

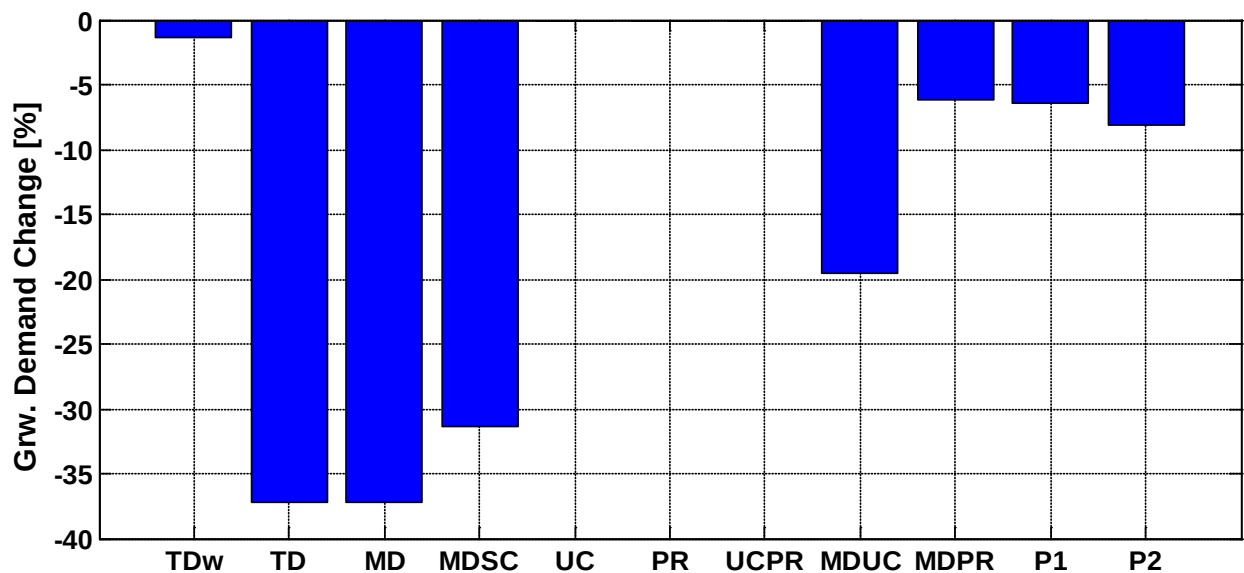


Figure 159 - Change in Groundwater Demand for Climate Change Augment Condition Cases

All of the cases that have allocations freed up for groundwater recharge or reducing groundwater demand include some form of desalination. Given the operating behavior for each measure used in this study, this occurs since the steady-state nature of desalination plants allows the production of water during periods when the water demand is low. This allows more water allocations to be

freed up for groundwater recharge, and is in contrast to the other measures which follow the temporal trends of the water demand and do not further reduce reservoir demand when it is already small. This occurs in both standard and climate change augment conditions.

Under baseline conditions, the cases are able to reduce the statewide groundwater demand by up to 6.3% with the pure desalination cases. The case where desalination plants are biased towards southern California reduces groundwater demand by 5.1%, since a lower total capacity is installed. Thermal desalination with waste heat reduces the groundwater demand by 1.95%, mostly concentrated in northern California.

Under climate change augment conditions, a similar pattern emerges but at larger scale. Due to the significantly larger capacities of steady-state desalination required to stabilize surface reservoir levels, significant amounts of water are produced during low demand periods. This allows a large amount of water allocations to be freed up for groundwater recharge. The pure desalination cases reduce up to 37% of current groundwater demand, with the hybrid cases exhibiting reductions between 6.3% and 19% depending on technology mix.

These results have positive implications for potentially reducing groundwater overdraft in this region, which has become a concern over recent years. To achieve these benefits in the practical setting, however, strong coordination of water management between centralized and local water authorities must be present.

5.2.1.4. Discussion

When evaluating options to stabilize surface reservoir levels and the water supply as a whole, the advantages and disadvantages of each option on a wide range of criteria must be evaluated. This is important for understanding the role that different options are best suited to fulfill as part of a

portfolio for securing the water supply. Some of these characteristics have been quantitatively evaluated in this study for this system: water savings potential, spatial distribution, and potential for groundwater recharge. Other quantitative criteria such as energy consumption, greenhouse gases, and implications for the renewable portfolio standards will be evaluated in Water-Electricity coupling study.

There are many other characteristics of each option, however, that shape its potential role as part of the water supply stabilizing option portfolio. Many of these options may be difficult to quantify because they are based in a more practical nature such as implementation advantages or challenges and handling of reject products such as brine. These considerations are discussed for each option here. In California, wastewater treatment plants must apply for a permit and be approved to discharge effluent into the local environment. The implementation of water reuse can alleviate this burden by reducing discharge levels and redirecting effluent for additional treatment. Full scale implementation of reuse could potentially exempt wastewater treatment plants from the requirement of obtaining a discharge permit and from paying the associated costs. Additionally, in 1980, the EPA identified drinking water treatment plants impacted by upstream wastewater treatment plant discharges, and found the top 25 most impacted plants contained between 2% and 16% wastewater discharges from upstream locations under average stream flow conditions. Any increase in planned water reuse implementation potentially decreases the volume of treated wastewater discharge into water bodies and consequently abates the aforementioned negative impacts. Finally, reductions in the energy needed to transport water from other areas can be realized since water reuse is implemented in the local context. This is described in more detail in the Water-Electricity coupling study.

Water reuse projects, however, face serious challenges regarding the public perception and concern for the trace hormones, pharmaceuticals, and human viruses in treated wastewater, the elimination of these contaminants from reused water, and the removal efficiency of the remaining contaminants by conventional and advanced drinking water treatment processes [263]. Additionally, N-nitrosodimethylamine (NDMA), which has been classified as a human carcinogen by the US Environmental Protection Agency [264] is another emerging concern in water reuse implementation, specifically with potable purposes. This compound is detected in the secondary wastewater treatment and throughout the advanced purification treatments (e.g. MF and RO) and necessitates employing an expensive advanced oxidation process (e.g. UV radiation) in combination with RO treatment to reliably maintain the residual NDMA below the acceptable level in reused water production [265].

Desalination of seawater extracts freshwater from seawater and leaves a stream of highly concentrated reject brine. Seawater typically has a salinity of about 36 ppt, causing reject brine TDS (total dissolved solids) levels to be about 60-85 ppt. Plants that use chemicals such as coagulants, anti-scalants, polymers, or disinfectants for desalination pretreatment could see these chemicals in the effluent brine [266]. Currently, the predominant method for disposing seawater desalination plant reject brine is to discharge the effluent back into the ocean. This practice can affect ecosystems by stratifying the water body, creating a briny bottom layer that can impact benthic communities [267]. Additionally, chemical products found in desalination brine have the potential to cause adverse impacts on local communities. Recent ecological monitoring has found variable effects ranging from no impact to widespread sea grass, coral reef and other ecosystem alterations [268]. These effects are particularly noticeable in poorly mixed areas.

To prevent the negative ecological impact to the environment, California requires implementation of safe practices, such as appropriate discharge site selection, blending with another source of low salinity water (i.e. sewage effluent) and installation of efficient diffusers at the end of discharge pipes to improve the mixing rate. New diffuser technologies are being further explored for reducing the impact of saline brine on coastal areas. Many novel methods have also been developed to aid in extracting the valuable salts and metals from desalination reject brine. For example, Ma [269] reports application of solid inorganic adsorbents to extract lithium chlorides. Membrane distillation-crystallization technology was utilized to recover sodium chloride crystals from reverse osmosis reject brine [270, 271]. Desalination brine was also proposed in the application of CO₂ sequestration by conversion of calcium and magnesium ions into dolomite and magnesium biocarbonate while reducing TDS from discharging water [272, 273]. With a well-managed system, options are available to minimize the negative impact of desalination brine discharge to the coastal region.

While water conservation practices are beneficial, innovations to conserve water face many implementation challenges. For example, demand-side approaches may burden economically-disadvantaged groups by ignoring their ability to pay for water, or forcing them to install high-cost, lower-water using appliances. Residential metering may generate opposition due to fear that meters will not be accurately read and that residents will be charged for excess water usage [274]. Moreover, different jurisdictions may have conflicting goals toward metering – California experience is exemplary. Since 2004, state law mandates that new dwellings have meters and that utilities bill at metered rates. Before the law's passage, discretion for reading meters was left to local communities that, in some regions, opposed meters [9, 275].

Increasing bloc rate (IBR) pricing, an economic mechanism to encourage conservation, where customers are charged more per unit of water used once their volume of use exceeds an average-derived use level (i.e., a “conservation base”), also faces challenges. IBR may not account for ability to pay, especially for those on fixed incomes who, for health reasons, use more water. Equity issues have arisen where IBR rates have been adopted or under consideration - recently in communities in Orange and Los Angeles counties. Customer concerns include: how individual household budgets eligible for “conservation” rates are calculated; skepticism regarding whether increased rates are revenue neutral; whether customers are rewarded for efforts to conserve; the failure of water boards to communicate details of their proposed rate structures - including charges they must pay to the MWD because of losses of imported water from the Delta and elsewhere; and, elected officials’ frustration over the cost of enforcing conservation efforts and the lack of funds for appliance retrofits given tight budgets [276, 277]. Additionally, as income grows, so do *outdoor and indoor* demands. This tends to be true in regions that do not employ IBR but use uniform rates that charge the same amount per [9, 276]. Finally, some communities forbid measures that conserve water through, for example, removing lawns and replacing them with water-saving landscaping due to aesthetic reasons.

Innovations to better manage freshwater resources and respond to shortages – including use of reclaimed wastewater, stormwater reclamation and desalination face numerous public acceptance challenges. Public support for water reuse, for example, is higher for uses such as landscape irrigation or car washing that minimizes human contact [261]. Public acceptance is also a challenge for utilities contemplating water reuse and for firms to incorporate it in their production processes. Decision-makers must demonstrate why these innovations are to avert water shortages and that these water-saving schemes are safe. In addition, concerted efforts must

focus on properly maintaining water infrastructure, especially when it pertains to water reuse; on allowing stakeholders to monitor the uses and operations of wastewater recycling; and on vigilantly ensuring the protection of public and environmental health [278]. Finally, open and transparent decision-making processes in which individuals and groups affected by water decisions can equally participate, and where no important constituency (including “victims” of water crises such as women and the frail) is excluded, are required [279] to gain public support for alternative water supply stabilization options.

The authors acknowledge that climate models are subject to uncertainties due to model physics, initial and boundary conditions, and model parameters [250, 280-282]. Particularly, uncertainties of simulated climatic extremes are substantial [283, 284]. Today’s climate models cannot be used for projection of daily or annual conditions in future. Instead, they should be used to assess system’s behavior/response under prescribed climate scenarios.

5.2.1.5. Summary and Conclusions

5.2.1.5.1. Summary

This study evaluated the effectiveness of different water supply options for stabilizing major surface reservoir levels in California. A temporally and spatially-resolved model of California’s network of major surface reservoirs was created to capture the impact of deploying different water supply stabilization measures on securing water reservoir levels under historical and climate-change inflow and demand conditions. The potential contribution of measures including urban water conservation, water reuse, and three types of desalination was determined. The scale of these measures needed to stabilize net reservoir fill changes was then determined, and implications for the groundwater demand as well as social and implementation issues were discussed. The main outcomes of the study are as follows.

5.2.1.5.2. Conclusions

1. Under baseline conditions, many of the available options are able to stabilize or nearly stabilize surface reservoir levels in isolation. The only exception is thermal desalination with waste heat, which is limited due to the finite amount of waste heat present in coastal power plants in the state.

2. Under climate change augment conditions, including changes in inflow and increases in demand, a portfolio approach of measures will be required to stabilize surface reservoir levels. The only option which could theoretically scale up to stabilize surface reservoir levels is thermal desalination with natural gas and membrane desalination. Relying on these measures alone, however, requires extreme installed capacities which can have significant energy implications as well as brine management issues and ecological effects. Therefore, other measures may be implemented to reduce the amount of desalination required. Energy issues will be explored in the Water-Electricity coupling study of the study.

3. Deploying both water reuse along with conservation is not additive in terms of stabilizing reservoir levels, since conservation may reduce the potential capacity for water reuse. Under worst-case scenario climate change augment conditions, urban water conservation and water purification/reuse are insufficient to stabilize reservoir levels. Conservation, as will be described in the Water-Electricity coupling study, is a very important option for energy considerations, however.

4. The steady-state nature of desalination plants allows a large potential for reducing groundwater demand. By producing water even during low demand periods combined with coordinated and adaptive management of water allocations, allows a large

amount of water to be freed up for groundwater recharge or reducing groundwater demand. This is exacerbated with larger desalination capacities.

5. Coordinated management practices and policies are required to most effectively stabilize the water supply. Coordination between central and local water authorities are required to both regionally stabilize reservoir levels and take advantage of groundwater demand reduction potential. Changes in water management practices may be required as a part of these policies.

6. Finding points of leverage in the system are important for maximizing the effectiveness of deploying a given option. For this system, the South Coast and Colorado River regions were key points of leverage for maximizing the impact of a fixed capacity deployment of a given option. These types of points must be identified in every system to maximize effectiveness.

This study focused on the examining the details of different options for contributing to stabilize surface reservoir levels. The main outcome of this part of the study, however, is to achieve a sense of scale for the capacities of available technologies needed to stabilize surface reservoir levels, such that a more accurate sense of energy implications can be examined. This is the focus of the Water-Electricity coupling study, which will be presented in a following section.

Chapter 6: Holistic Evaluation of Sustainability Options in Paired Resource Sector Systems

This section presents an evaluation of sustainability oriented options within the context of two co-dependent resource sectors.

6.1. Electricity and Transportation

Some of these results have been previously presented in the following publications:

- **Tarroja, B.**, Eichman, J.D., Zhang, L., Brown, T., Samuelsen, S., *The effectiveness of plug-in hybrid electric vehicles and renewable power in support of holistic environmental goals: Part 1 – Evaluation of aggregate energy and greenhouse gas performance.* Journal of Power Sources, 2014. **257**(0): p. 461-470.

Additionally, sections of this text are described in publications that have been currently submitted to refereed journals as follows:

- **Tarroja, B.**, Eichman, J.D., Zhang, L., Brown, T., Samuelsen, S., “*The Effectiveness of Plug-in Hybrid Electric Vehicles and Renewable Power in Support of Holistic Environmental Goals: Part 2 – Design and Operation Implications for Load-Balancing Resources on the Electric Grid*”, Journal of Power Sources, 2013. **Submitted as of May 2013**

6.1.1. Plug-in Hybrid Electric Vehicles (PHEVs) on the Electric Grid

6.1.1.1. Literature Review

6.1.1.1.1. Aggregate Energy and Environmental Performance

Due to increasing interest in the development of alternative fuel vehicles over the past few years, much work has already been conducted to explore the interaction between plug-in electric vehicles and the electric grid.

A study performed by Jansen [97] provided some insight into the increase in the electric demand for the state of California due to plug-in vehicles, using a 40 percent penetration of PHEVs with a 40 mile all-electric range and uncontrolled charging behavior. The total electric load demand of a typical day was found to increase by 5-10 percent between the hours 9 am to 9 pm, and

suggested an increased reliance on peaking power plants during this period. Similar parameters analyzed in New York show smart charging can reduce electricity system costs [285].

The integration of plug-in electric vehicles can also affect criteria pollutant emissions from conventional power plants. A previous study found that PHEV integration would increase grid-average CO and non-methane organic compound emission intensities by 4 percent and 7 percent respectively between 9 am and 9 pm, and reduce the NO_x average emission intensity by about 3 percent between 5 pm and 9 pm. The total emissions of criteria pollutants of stationary and mobile sources combined, however, is expected to decrease as increases in power plant emissions are offset by reductions in mobile source emissions due to lower gasoline use. The translation to improvements in air quality is dependent on the time of day when emissions are decreased [286].

The facets of this interaction within the context of renewable integration have also been addressed to some extent.

Dallinger [192] conducted a study which examined the role of grid-connected vehicles in improving the integration of renewable energy sources in California and Germany. This study compared the regional differences between these systems, as well as the effect of different charging strategies: last trip charging, time of use tariff charging, and demand side management charging. The study found that last trip charging resulted in a reduced electric driving share, increased net load ramp rates, and contributed only a small amount towards balancing renewable resources. Time-of-use tariff charging was found to balance renewable power generation only if the net load profile was regular and periodic. With non-periodic renewable generation, time-of-use tariff charging did not provide enough flexibility to gain benefits. Demand-side management

charging was found to reduce net load ramp rates and was able to provide the most contribution towards managing variable renewable resources. This strategy was found to be more effective in California compared to Germany due to the characteristics of the load and renewable generation in that region.

Denholm [193] examined the benefits of an interaction between plug-in vehicle integration and solar PV deployment, specifically. This study found that mid-day charging of electric vehicles with solar PV can increase the amount of miles traveled using low-cost electricity and reduce the required battery size in plug-in vehicles. PHEV charging was found to provide a flexible source of electric load that can maximize the use of solar PV, especially during low load periods. Solar PV was also found to meet the burden of increased peak generation requirements due to mid-day charging. Overall, the study concluded that solar PV and PHEVs have important complementary characteristics. A case study in Brazil by Soares [113] examined the use of plug-in electric vehicles to maximize variable renewable integration. This study was conducted in anticipation of large wind power capacity that will be installed in the region in future years. It was discovered that a fleet of 500,000 PHEVs by 2015 and 1.5 million PHEVs by 2030 with overnight charging would allow the region to eliminate the onset of excess wind generation and reduce the need to significantly modify the electric power system.

Querini et al. show that GHG emissions are almost always reduced for PEVs utilizing renewable electricity compared to traditional gasoline or diesel vehicles, regardless of the manufacturing location or manufacturing techniques of the renewable technologies [287]. However, the study does not consider vehicle charging profiles or actual electric grid operating characteristics.

More studies regarding the development of optimization algorithms for vehicle charging within the context of renewable resources are outlined by Richardson [288], with respect to wind, solar, and biomass individual interactions with plug-in hybrid vehicles. Additional studies examining V2G capability in the context of renewable integration have also been considered [289-291].

Many specific aspects of the interaction between plug-in vehicles and the electric grid have been examined in the literature, even within the context of renewables. To date, however, there has only been little insight into this interaction within the context of meeting holistic sustainability goals. The majority of studies thus far have focused on PHEVs only as a complementary technology to the grid. Additionally, while the impact of PHEVs on the net load characteristics has been examined, little explicit insight has been given into the impact of these changes on the design and operation of load-balancing resources on the electric grid. The analysis herein aims to provide detailed insight into both of these aspects.

6.1.1.1.2. Impact of PHEVs on Electric Grid Operation

Examining the aggregated emissions and energy usage metrics alone only provides a part of the picture regarding the interactions and impacts associated with electric grid and transportation sector integration. The use of PHEVs with smart charging do not only affect the annual emissions and energy usage patterns of the electric grid, the character of their load profile also affects the design and operation of load balancing resources on the system. Balancing generators on the grid have many constraints on how dynamically these units can operate, including but not limited to part-load turndown limits, ramping limits, and start-up event limits. Changes in the character of the net load profile that these units must meet also have implications for the efficiency, capacity factor, distribution of load-following and peaking capacity of the balancing generator fleet and the levelized cost of electricity from this system.

Many studies have identified that the variable nature of wind and solar power increases the dynamics of the net load profile and therefore the strain on balancing generators [214, 223]. These studies imply the need for complementary technologies to mitigate these issues. However, very few studies have been conducted to date that examine the potential for the use of PHEVs as a complementary technology in obtaining a synergy with the electric grid by providing benefits for the operation of load-balancing resources.

Dallinger [192] conducted a study which examined the role of grid-connected vehicles in improving the integration of renewable energy sources in California and Germany by examining the impact on the net load profile. This study compared the regional differences between these systems, as well as the effect of different charging strategies: last trip charging, time of use tariff charging, and demand side management charging. The study found that last trip charging resulted in a reduced electric driving share, increased net load ramp rates, and contributed only a small amount towards balancing renewable resources. Time-of-use tariff charging was found to balance renewable power generation only if the net load profile was regular and periodic. With non-periodic renewable generation, time-of-use tariff charging did not provide enough flexibility to gain benefits. Demand-side management charging was found to reduce net load ramp rates and was able to provide the most contribution towards managing variable renewable resources. This strategy was found to be more effective in California compared to Germany due to the characteristics of the load and renewable generation in that region.

Wang [158] investigated the effects of PHEVs on power systems with demand response and wind power. The net load profile was used to evaluate the impacts on the Illinois power system in 2020. It was discovered that by acting to level the load demand, system costs can be decreased

significantly, and further decreased by using demand response measures in conjunction. Druitt [292] examined the use of EVs to balance the electric load demand with increased wind penetration levels, also focusing on the effects on the net load profile and pricing signals. It was discovered that EVs were well suited for the uptake of variable renewable power in the UK and improved load-following conditions in both demand management and vehicle-to-grid operation modes.

Other studies have focused on characterizing the profile of the PHEV charging load in relation to the stationary load demand. Zhang [61] examined the use of PHEVs with different all-electric-ranges as a function of charging location and charging strategy. It was discovered that immediate home charging exacerbates the grid load peak and delayed charging acted to smooth the load profile on average. Charging at non-home locations increased loads during the daytime. Bashash [293] examined the profile of the PHEV load using a charging strategy that focused on maximizing vehicle battery life. This introduced a PHEV load peak in the early-mid morning hours. Weiller [294] examined the characteristics of the PHEV charging load as a function of charging location options. Charging at home only caused increases in the net load demand during the late afternoon and early evening hours, whereas charging at home, work, and commercial places tended to smooth out the PHEV profile. Other studies have provided into aspects of this area as well [43, 291, 295, 296].

Overall, however, few studies focus on the effect of PHEV charging on the operation of balancing generators on the electric grid in the context of renewable power generation. The studies that are currently present in the literature have shown implications for the operation of these resources through examining effects on the net load profile that these generators must

meet. Currently, however, no study has examined the effect on the required design and operation of these generators explicitly, especially with regards to operating constraints such as the need to provide ancillary services and technological limitations of different generator types. This part of the study seeks to provide insight into this topic by examining explicitly the effectiveness of using PHEVs on the design and operation of balancing generators on the electric grid.

6.1.1.2. Approach

6.1.1.2.1. Scenarios for Analysis

In this study, the electricity and transportation systems of the state of California are used as the object of analysis. California currently has set aggressive deployment goals for zero-emission vehicles and renewable power installations. California also has a large population that contributes to high electric total load and light-duty transportation demands. The state also has access to a variety of renewable resources. These characteristics make it ideal for examining multi-sector interactions. The year 2005 is used as the representative year for all of the datasets input into the models for this study.

In order to examine the benefits and disadvantages of integrating transportation and the electric grid, a number of scenarios are examined.

Base Renewable Penetration: This refers to the percentage of the total electric load that is served by renewable energy without any interface with transportation (i.e. no PHEVs). Each base renewable penetration increment corresponds to given capacities of installed renewable resources including solar PV, solar thermal, wind, geothermal, biomass, and small hydropower. Therefore, the effect of interfacing with PHEVs can be determined for fixed renewable capacities to display benefits or disadvantages more clearly. Note that this differs from the actual renewable penetration which was used as a metric for the analyses in Section 5.

The Base Renewable Penetration is defined as the ratio of the amount of renewable energy delivered to load (taking into account losses and curtailment) to the total energy of the load. For reference, as of 2013, California stands at roughly 20% base renewable penetration with a goal of 33% by 2020 [297]. The mix of renewable resources as a function of base renewable penetration level is presented in Figure 160:

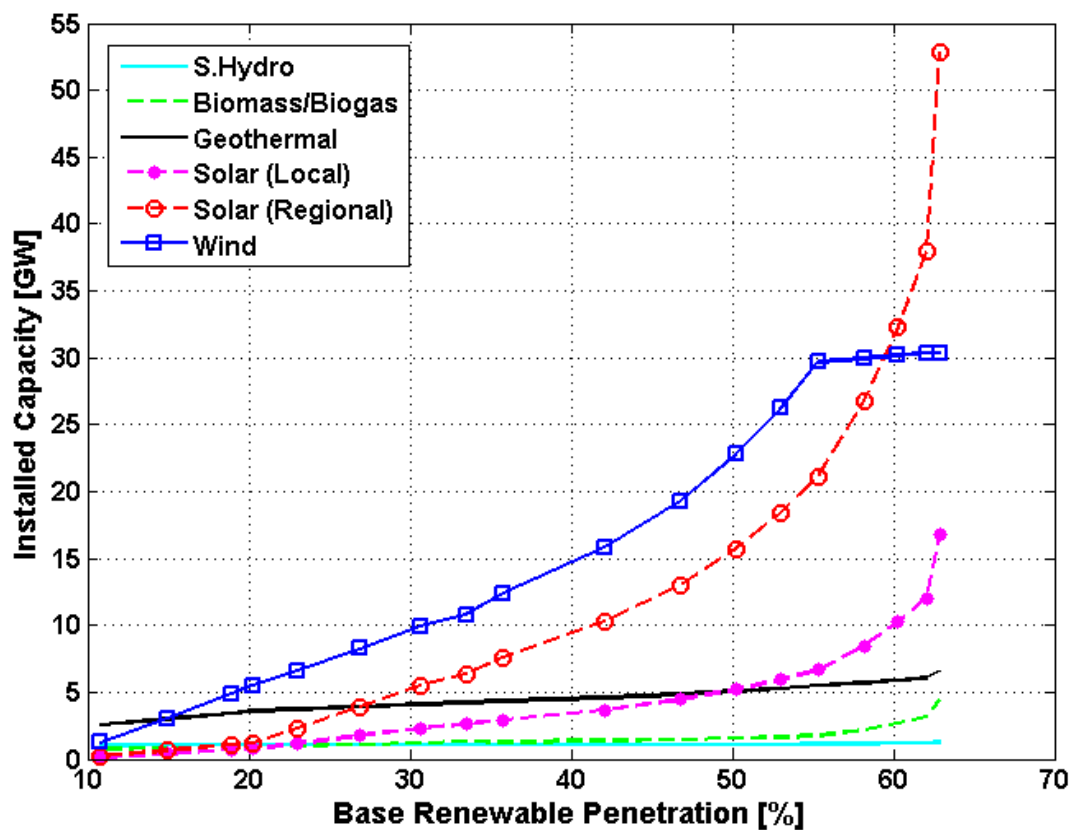


Figure 160 - Renewable Mix vs. Base Renewable Penetration Level

The renewable deployment curve was developed using the specifications for the percentage of energy delivered by each renewable resource in the California Public Utilities Commission's 33% RPS Implementation Preliminary report [298]. The figures specified in this report, however, did not take into account the effects of base load generation, potential renewable curtailment, and

the presence of reliability margins. Therefore, the capacities specified in the report were adjusted to meet the specified energy percentage served by each type of renewable resource. This produced a slightly different renewable deployment curve from that used by Tarroja [221], which also used the same report but did not have any uninterruptible base load capacity. Above the 33% renewable penetration level, the renewable mix by energy was assumed to be constant. Further, the range reaches its maximum at a 65% base renewable penetration level, since the presence of high base-load capacities hinder the use of many renewable types to serve the load [43, 148]. Nuclear power capacity was assumed to be constant across all scenarios, whereas coal power capacity was set to decrease with renewable penetration in reflection of current trends in California. The progression of the base load coal capacity is an extrapolation of the coal generation trends from 2005-2011 displayed by the California Energy Commission Total Electricity System Power [299]. The energy delivered is converted to capacity using representative coal plant capacity factors from eGRID [300]. Coal capacity is set to reach zero by the 33% base renewable penetration level.

PHEV Penetration: This refers to the percentage of the total light duty passenger vehicles in the state that are PHEVs. It is important to note that this penetration number does not necessarily correspond to the fraction of electric vehicle-miles-traveled in the state. Since PHEVs have a limited electric range, miles from any trip exceeding this range will be fueled by gasoline. The PHEV penetration levels considered are shown in Table 57.

Table 57 - Number of Vehicles at Different PHEV Penetration levels

<u>PHEV Penetration [%]</u>	<u>Number of Vehicles</u>
1	211148
2	422297
3	633446
4	844595
5	1055744
10	2111488
15	3167232
20	4222976
25	5278720
30	6334464
35	7390208
40	8445952
45	9501696
50	10557440
55	11613184
60	12668928

It is important to note that the California initiative to deploy 1.5 million ZEVs by 2025 [31] would amount to roughly 6.3% of the projected on-road light duty fleet in that year. Assuming 20% ZEV sales growth per year in line with California Air Resource Board projections, 15% ZEV penetration will not be reached until roughly 2030. As a result, 15% PHEV penetration and 40% electricity renewable penetration (per Hawaii initiative) appears to be a reasonable estimate for the year 2030. Due to the inherent slow turnover rate in on-road vehicle fleets, any PHEV penetration higher than 15% appears unlikely before 40% renewable penetration is reached in California; regardless, the analysis herein spans all possibilities.

To be consistent with the load data used in the electric grid module, the total vehicle population of the year 2005 is used for reference. In this study, the all-electric range of the PHEVs is assumed to be 35 miles. This study also assumes that the entire light-duty VMT represents passenger cars with normal household utilization. Additionally, the use of ‘smart’ charging

dispatch from Zhang [61, 152] and Eichman [43] is implemented. This charging strategy assumes that the electric vehicle charger receives information about the behavior of the net load profile over the entire window for which the vehicle is to be charged. The charger will then optimize the charging profile to complement that information.

A home-charging infrastructure is assumed to be in place, with ‘Level 1’ 1.44 kW chargers. This assumption is based on the fact that light-duty vehicles spend about 75% of their residence time at home, and only 14% at the workplace [49, 61]. Therefore, the window over which the smart-charging profile can be optimized is much larger with home charging, whereas work charging may only provide limited additional flexibility [152]. Additionally, modern detached homes already have the infrastructure necessary to accommodate Level 1 vehicle charging. Expansion of the charging infrastructure to workplaces and activity areas is possible, but may cause significant increases in infrastructure cost compared to the incremental benefit gained [152].

6.1.1.3 Results

6.1.1.3.1. Energy Metrics and GHG Emissions

Model results simulate the effect of PHEV integration on the consumption of fossil fuels, renewable energy, and the emissions of GHG from the perspective of the combined electricity and light-duty transportation sectors.

6.1.1.3.1.1. Behavior of the Grid Renewable Penetration Level

A surface plot showing the change in the renewable penetration level from the base value with the addition of PHEVs is shown in Figure 161 with an inset in Figure 162.

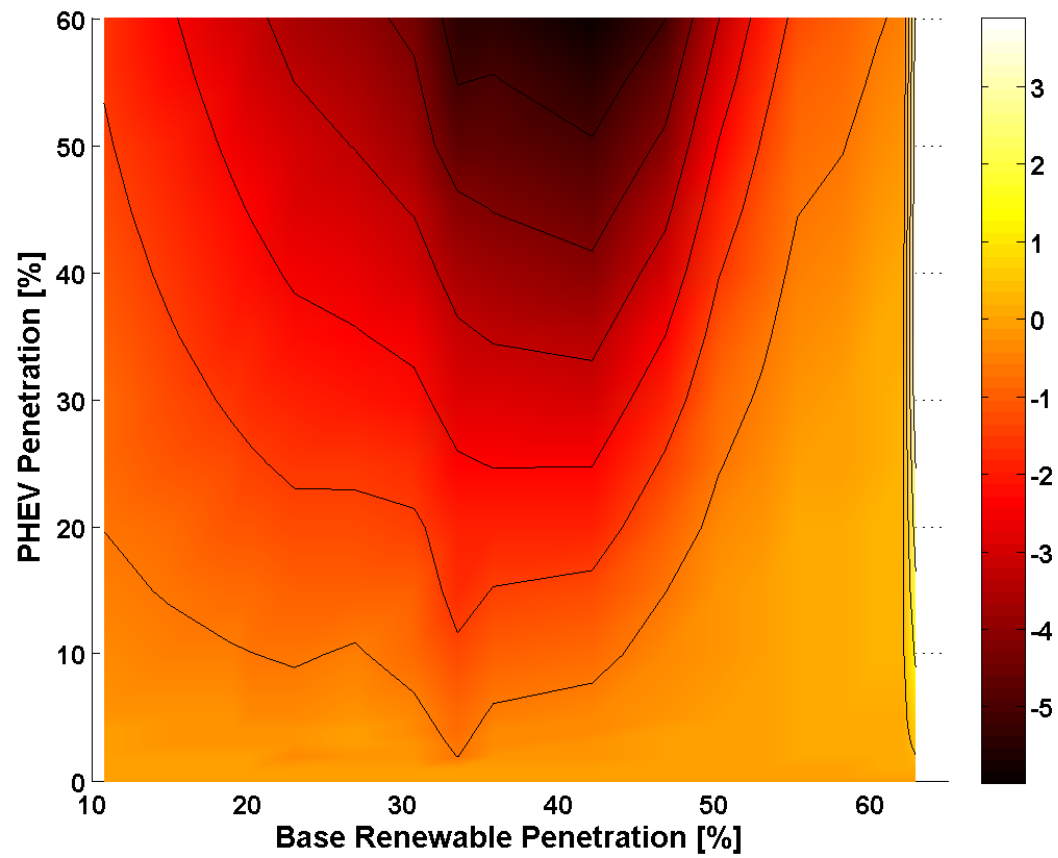


Figure 161 - Change in Renewable Penetration from the No-Transportation Case

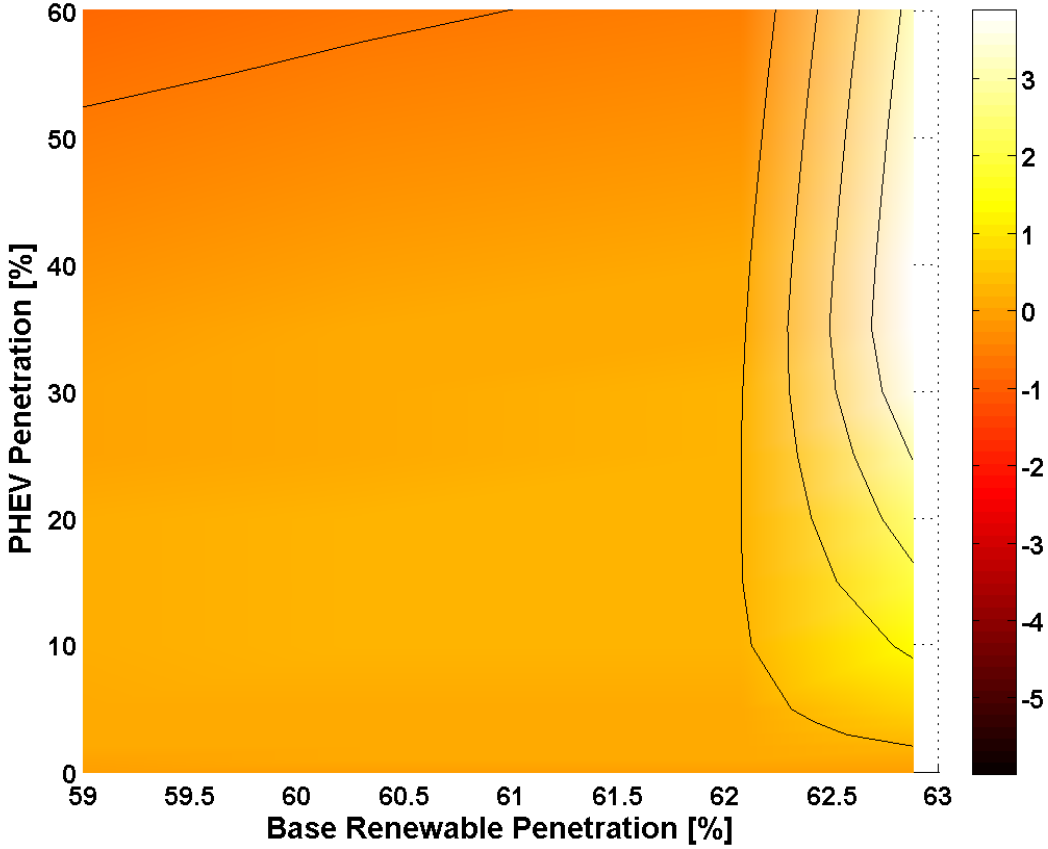


Figure 162 - Change in Renewable Penetration from the No-Transportation Case (Inset)

Recall that the definition of renewable penetration is:

$$R_{pen}[\%] = \frac{E_{Ren,delivered}}{E_{load}} \times 100$$

With regards to the integration of PHEVs, there are two competing forces that affect the change in renewable penetration from the base level.

First, the introduction of PHEVs onto the grid increases the overall electric load demand. For example, at a 60% PHEV penetration level with a 35 mile all-electric range, the energy of the electric load demand increases by 18.25%. This acts to decrease the renewable penetration level

from the base value by increasing the denominator (E_{load}), since a given amount of delivered renewable energy will count for a smaller fraction of the total load.

Second, the integration of PHEVs with smart charging capability acts to smooth out the load profile to the extent possible, constrained by consumer requirements, charging power, and battery capacity. In this case, PHEV charging acts to add load during periods when the net load demand is low, and refrain from adding load when the net load demand is high. This behavior can prevent curtailment of renewable power during certain periods, and serves to increase the renewable penetration level from the base value since renewable energy that would otherwise have been curtailed would be allowed to serve the load demand.

In general, curtailment of renewable power can occur for a number of reasons. For example, when renewable power generation increases, the dynamic balancing generator fleet must turn down in power output. This can involve operating at part load conditions, or shutting down individual generators. There are limits to the extent to which this can occur, since some capacity of dynamic balancing generators must be online for reliability requirements, and these generators individually have minimum part-load operating limits due to emissions constraints. Additionally, base-load generators that are online cannot shut down or decrease power output quickly or to any large extent. If an increase in renewable generation is so large that it causes the net load demand to drop below the sum of the power output from base-load power plants and the minimum power level of the dynamic generator fleet, a portion of the renewable generation must be curtailed in order to maintain reliability and emissions requirements. Fossil fueled generators also have minimum operating times, for example, if a natural gas fired load-following plant is activated, on average it must operate for at least 8 hours [50]. Additionally, if the net load decreases more

quickly than the ramp-down capability of the dynamic balancing generator fleet, renewable generation may have to be partially curtailed. The integration of PHEVs with smart charging acts to prevent these effects. When the net load is low during periods of high renewable generation or simply low stationary demand, vehicle charging load can be added. This acts to increase the numerator ($E_{Ren,delivered}$), by allowing more of the renewable energy to serve the load demand.

With those forces in mind, the behavior of the change in renewable penetration shown in Figure 161 can be understood. For most of the base renewable penetration range considered here, the addition of PHEVs decreases the renewable penetration level from the base value because this region corresponds to low installed renewable capacity, and renewable generation is not large enough to cause significant amounts of curtailment. Therefore, the primary effect is to increase the energy of the load demand, with larger increases occurring with higher PHEV penetrations.

The larger decrease at base renewable penetrations between 30% and 45% and high PHEV penetration levels occur simply due to the fact that the renewable penetration level is more sensitive to additions of a constant load level at higher base levels from a difference standpoint. For example, consider the 60% PHEV penetration level which increases the energy of the load demand by 18.25% at the 10.7% base renewable penetration level and a load of 100 energy units:

$$Rpen_{orig} = \frac{E_{Ren,delivered}}{E_{load,orig}} = 10.7\% = \frac{10.7}{100}$$

$$Rpen_{PHEV} = \frac{E_{Ren,delivered}}{E_{load,orig} + E_{load,PHEV}} = \frac{10.7}{100 + 18.25} = 9.05\%$$

$$\Delta Rpen = Rpen_{orig} - Rpen_{PHEV} = 10.7\% - 9.05\% = 1.65\%$$

Now consider the same load added at a base renewable penetration of 30%:

$$Rpen_{orig} = \frac{E_{Ren,delivered}}{E_{load,orig}} = 30.0\% = \frac{30}{100}$$

$$Rpen_{PHEV} = \frac{E_{Ren,delivered}}{E_{load,orig} + E_{load,PHEV}} = \frac{30}{100 + 18.25} = 25.37\%$$

$$\Delta Rpen = Rpen_{orig} - Rpen_{PHEV} = 30.0\% - 25.37\% = 4.63\%$$

Therefore, the difference in renewable penetration from base is expected to be larger at higher base renewable penetrations when the first effect dominates.

As the base renewable penetration increases above the 45% mark, the second effect begins to be present. In these regions, the renewable capacity is large enough such that curtailment due to over-generation or quick ramping becomes substantial. The PHEV load in these cases is dispatched, through smart charging, during periods of high renewable power generation and is able to keep the net load above the sum of the power output from base-load power plants and the minimum power level of the dynamic generator fleet. This allows renewable energy that would otherwise be curtailed to be used to serve the load, and the decrease in renewable penetration from the base case starts to be reduced. The PHEV load is able to restore the renewable penetration level to base values.

At the very highest renewable penetration levels (above 60%), the renewable penetration level increases from the base value due to the effect of PHEVs. For the parameters considered here, the maximum increase in the renewable penetration level from base is +3.87%, increasing from 62.87% to 66.74% at a 35% PHEV penetration level. In these cases, however, there is a limit to the extent to which PHEV charging load dispatch can increase the renewable penetration level, since the renewable capacities can become so large such that the PHEV load is only able to

reduce curtailment as opposed to prevent it. In general, the energy of the PHEV load is generally small compared to the energy obtained from renewable resources at high penetration levels, and is therefore limited in its ability to provide benefits. There is also an additional limitation due to the variable flexibility of the PHEV charging load. The use of home charging causes the majority of the charging load to be dispatched during the nighttime, when a large amount of vehicles are plugged into the grid and the residence time of these vehicles is typically long. This tends to complement wind power in California, but not solar power. Implementing the ability to charge at home and work was found to help alleviate this problem, but only slightly. This occurs since daytime charging reduces solar power curtailment but removes load from the nighttime hours and increases wind power curtailment since the energy of the PHEV load is fixed for a given PHEV penetration level. Overall, the use of PHEVs with smart charging can provide benefits for the electric grid renewable penetration level, but only under certain conditions. To obtain this benefit, the size and flexibility of the PHEV load must complement the behavior of renewable generation.

6.1.1.3.1.2. Behavior of the Renewable VMT and Gasoline Usage

The interface of the electricity and light-duty transportation sectors in the context of renewable electricity also affects the renewable penetration of the light-duty transportation sector. Even when using electric vehicles, much of the energy used to provide this electricity is still sourced from fossil fuels. While a reduction in fossil fuel use does occur, the extent of this reduction will depend on the electric generation portfolio. As the renewable penetration level of the electric grid increases, the extent of this reduction can be more significant. Figure 163 shows the vehicle-miles-traveled (VMT) that are actually fueled by renewable electricity:

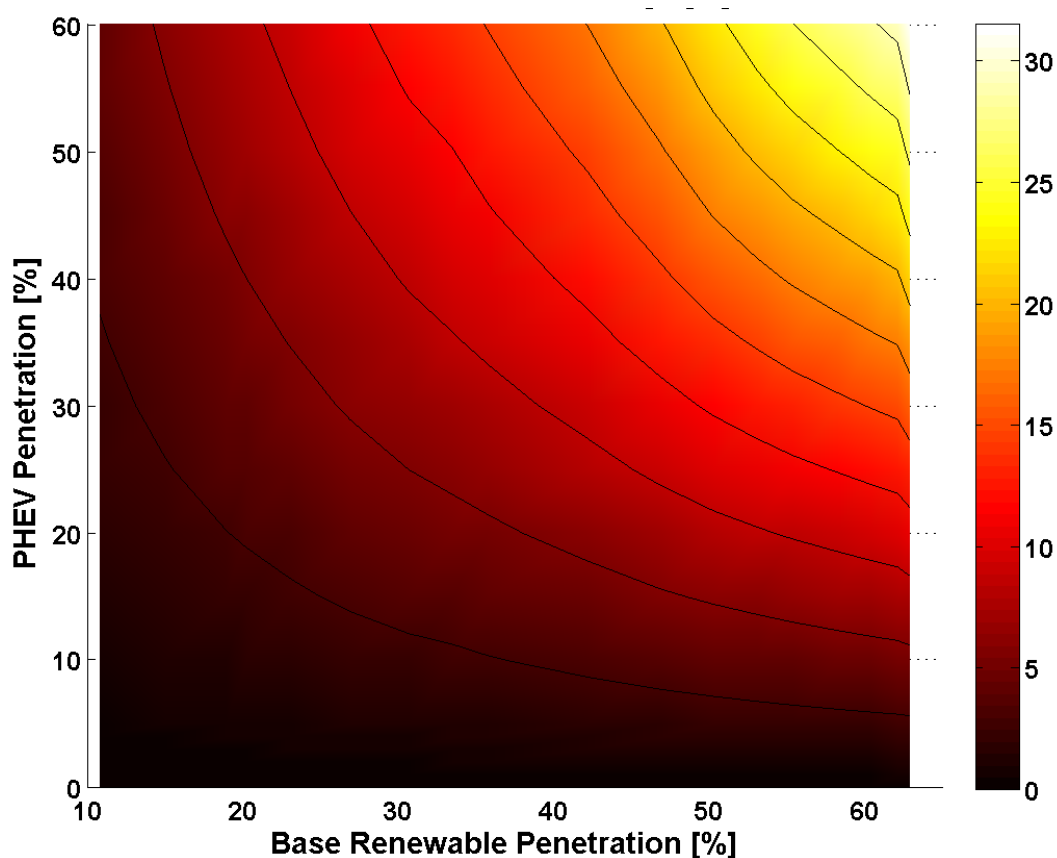


Figure 163 - Renewable VMT Percentage

With the 35 mile all-electric-range assumption, electricity could be used to fuel approximately 76.2% of the vehicle miles traveled in California if all vehicles were PHEVs according to the model results. Of that percentage, however, only a fraction would actually be powered by renewable electricity since only part of the electric energy obtained from the grid is renewable. For the cases considered in this analysis, the maximum renewable VMT is about 31.48%, with a 60% PHEV penetration and a 62.8% base renewable penetration level (66.2% actual). With 60% PHEVs, about 45.7% of all VMT is fueled by electricity, but only 66.2% of that electricity is renewable. This indicates that 78% of the vehicle-miles-traveled are still fueled by fossil fuels, with 23.6% attributed to coal and natural gas electricity, and 54.3% coming from gasoline or diesel. Therefore, PHEVs are highly reliant on the ability of the electric grid to reach high

renewable penetration levels in order to operate on renewable energy. Furthermore, given the incredible cost of increasing renewable electricity penetration beyond 62.8% without reductions in base load capacity or the use of complementary technologies [17], it appears difficult to achieve transportation renewable usage beyond approximately 20% given the realistic vehicle and charging parameters considered here. These results confirm the need for additional alternatives for transportation such as hydrogen and biofuels.

On the other hand, the use of PHEVs does serve to linearly reduce gasoline consumption by shifting the transportation fuel mix towards coal, natural gas, and renewables. The latter are generally cleaner burning and more efficient from a primary energy conversion standpoint than the combustion of gasoline due to their centralized nature and ability to use extensive emissions cleanup equipment such as selective catalytic reduction (SCR). For PHEVs with a 35 mile all-electric-range, light-duty transportation sector gasoline usage decreases by about 0.77% for every 1% increase in PHEV penetration.

6.1.1.3.1.3. Behavior of the Combined Fuel Usage and Combined Renewable Fraction

Holistically, the effect of utilizing PHEVs and renewable electricity must be viewed by their effects on not just the grid alone or light-duty transportation sectors alone. These interactions must be viewed in the context of its sustainability goals and that of the combined sectors.

The change in the combined fuel usage of the electric and light-duty transportation sectors is presented in Figure 164. The total energy usage is determined by combining the energy equivalent of all fuels used (coal, nuclear, natural gas, gasoline, etc...)

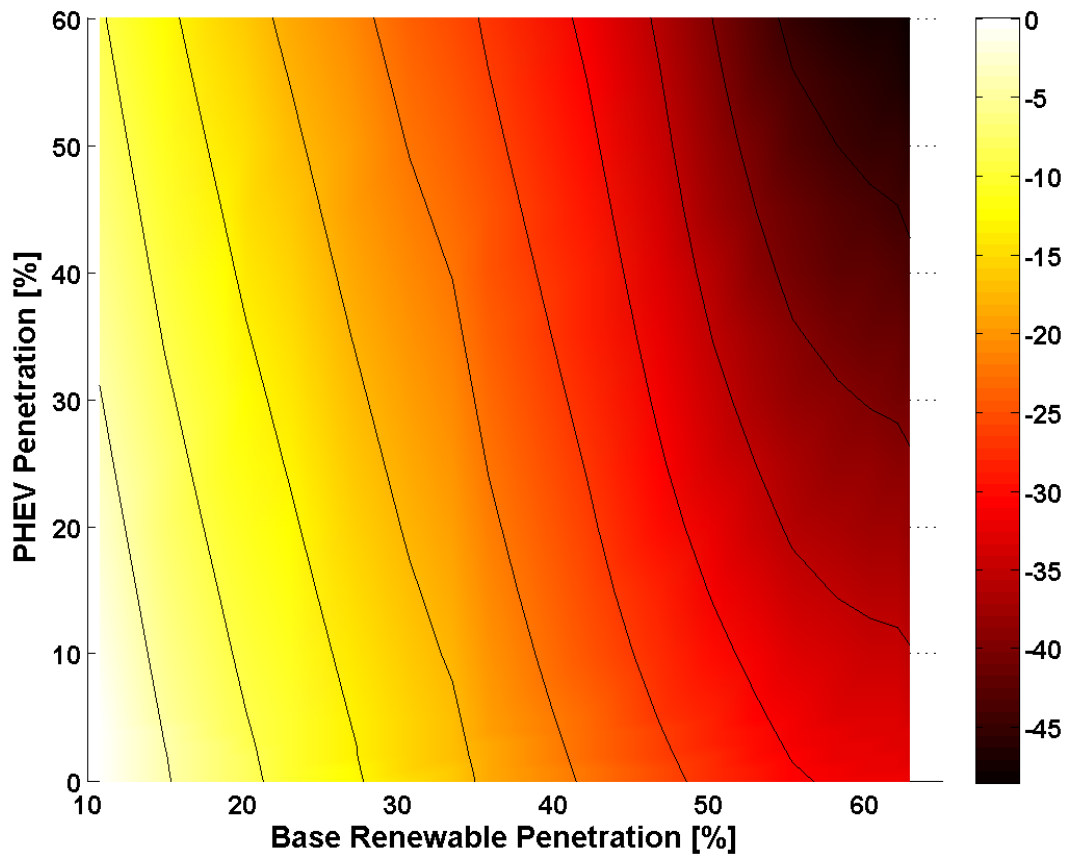


Figure 164 - Percentage Change in Combined Fuel Use of Electricity and Light-duty Transportation Sectors

As the base renewable penetration and PHEV penetration level increases, the combined fuel use of both sectors decreases. This occurs due to the fact that electric vehicles are very efficient from a well-to-wheels perspective and are able to provide much more VMT per unit of input energy compared to gasoline vehicles.

Overall, however, the fuel use of the combined electricity and light-duty transportation sectors is more sensitive to base renewable penetration than PHEV penetration. This occurs because while using PHEVs may significantly decrease gasoline consumption and render the light-duty transportation sector more efficient, this is slightly offset by a small increase in grid fuel consumption, rendering the net decrease in fuel consumption smaller. In contrast, increases in the

base renewable penetration level contribute wholly to reducing generation from non-renewable primary resources.

The greatest reductions in fuel usage occur when both the PHEV penetration and renewable penetration levels are increased, since these strategies complement each other. Increasing PHEV penetration levels reduce gasoline but increase grid load. Increasing renewable penetration complements this by reducing the fuel consumption of the electric grid per unit of load served, offsetting the increase in grid fuel consumption due to the addition of the PHEV load. Combined, large reductions in fuel use can be garnered. On an energy basis, reductions of nearly 49% can be obtained for the scenarios examined in this analysis.

This further highlights the benefit of taking advantage of synergies between sustainability initiatives in the transportation and electricity sectors to provide holistic benefits.

To further understand combined sector performance, the combined primary renewable fraction is examined. This metric is different than renewable penetration since it represents the fraction of the total primary energy use that is served by renewable energy as opposed to the energy of the electric load demand:

$$Rfrac_{primary} = \frac{E_{Ren,delivered}}{E_{use,primary}} = \frac{E_{Ren,delivered}}{E_{fuel} + E_{Ren,delivered}}$$

Even in the electric sector alone, the primary energy use is larger than the energy of the electric load demand since fuel must be converted to electric energy to serve the load with a significant efficiency penalty. For example, consider a 1 GWh load which requires 1GWh of generation to serve. With an example average grid efficiency of 35%, providing that generation consumes 2.86 GWh equivalent of primary energy in fuel. Therefore, a 10% renewable penetration would

signify 0.1 GWh of renewable energy delivered in this case, which would only equate to a 3.95% primary renewable fraction! It is also important to note that this metric uses the renewable energy delivered as a representation of renewable energy utilization. While renewable energy resources are not 100% efficient from an input-to-useful energy basis, utilizing these resources does not require consumption of a practically finite resource. For calculating fuel use, fuel must be consumed only to obtain a fraction of its energy as useful output. In contrast, the losses from primary renewable energy input to renewable energy delivered (i.e. energy in the wind stream to energy obtained from a wind turbine) do not represent energy that is consumed by the electricity sector. Therefore, the delivered renewable energy is used directly.

The combined primary renewable fraction considers the primary energy use of the light-duty transportation sector in addition to that of the electric sector in the denominator of the definition provided previously. Overall, this metric represents what fraction renewable energy contributes to the total energy usage of both sectors combined, and is presented in Figure 165:

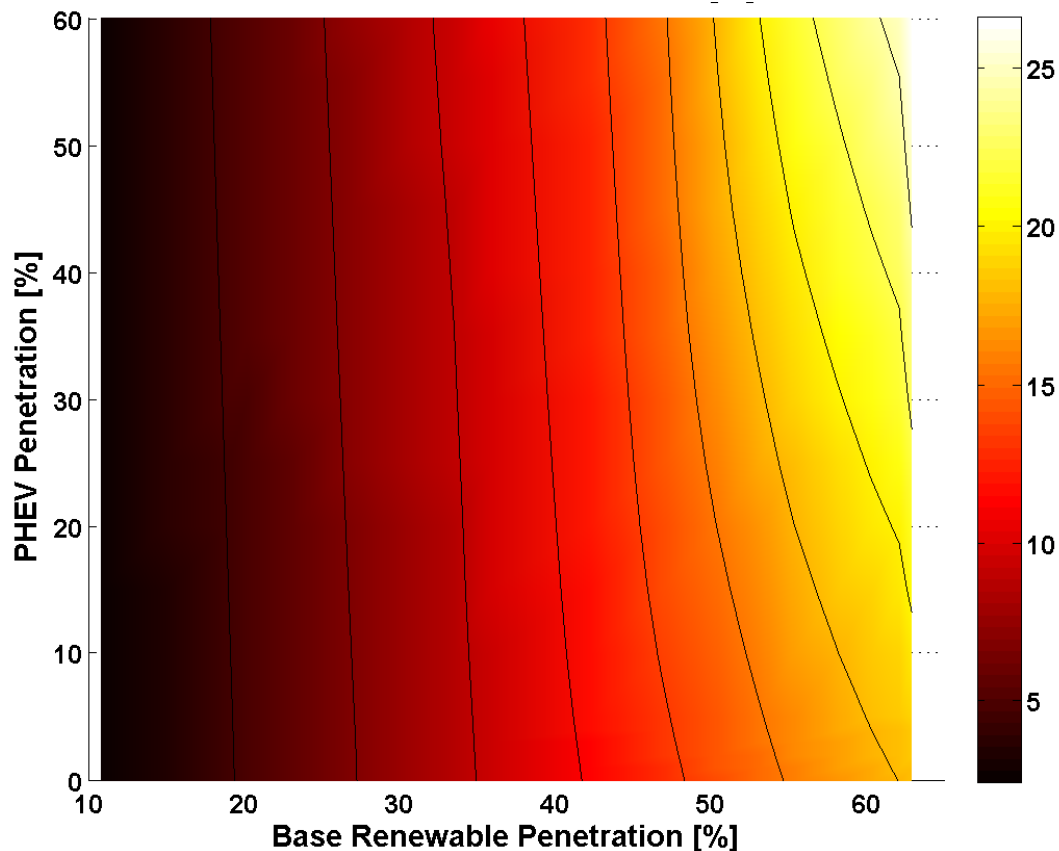


Figure 165 - Combined Renewable Fraction

At low base renewable penetration levels, the combined renewable fraction is primarily sensitive to changes in the installed renewable capacity. Increases in the base renewable penetration level represent increases in the delivered renewable energy and reduces the fuel consumption of the electric grid, which increases the combined renewable fraction. PHEV penetration only affects the combined renewable fraction in these cases by reducing the total energy consumption of the light-duty transportation sector and imposing a smaller increase in primary energy consumption in the electric sector. Additionally, at low to mid renewable penetration levels, all of the energy obtained from renewable resources is being used to serve the aggregate sectors and curtailment is at a minimum. Therefore, PHEV penetration does not significantly influence the combined renewable fraction at low base renewable penetration levels.

At higher base renewable penetration levels, the combined renewable fraction becomes sensitive to PHEV penetration level. In these cases, the balancing effects of PHEV smart charging prevents or minimizes renewable curtailment and increases the amount of renewable energy utilized by the aggregated sectors from the base value. With the scenarios considered in this analysis, the combined renewable fraction reaches a maximum of 26.55%.

The first characteristic to notice is that the magnitude of the combined renewable fraction is considerably smaller than the renewable penetration or the renewable VMT as presented previously, as explained prior. This also occurs since much of the transportation VMT and electric load is still met by fossil fuel sources, which are generally not highly efficient and therefore require large fuel inputs to meet a given electric load and/or VMT demand. Increasing the combined renewable fraction would require 1) increasing the efficiency of mechanisms that meet the VMT and electric load demand – vehicles and power plants, and 2) increasing the amount of energy obtained from renewable resources – not just those in the electricity sector, but even resources and pathways that move directly to serve the light-duty transportation sector

6.1.1.3.1.4. Behavior of the Combined GHG Emissions

Goals for reductions in GHG emissions should transcend the behavior of any individual resource sector and consider a holistic approach. It is not beneficial for one sector to increase GHG emissions in a manner that offsets reductions in another, and certain sectors have more potential for GHG reduction than others. For the electricity and light-duty transportation sectors, the reduction in combined GHG emissions from base 2005 levels (10.7% base renewable penetration) is presented in Figure 166:

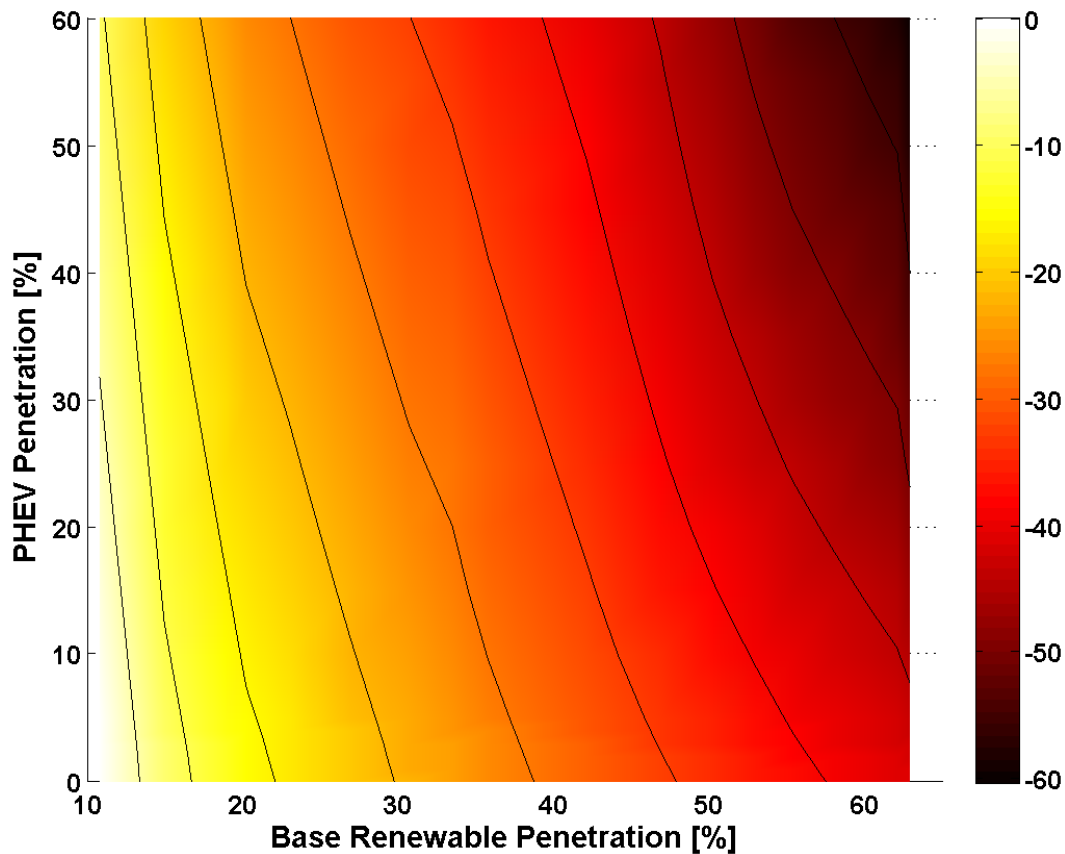


Figure 166 - Percentage Change in Combined GHG Emissions

The combined GHG emissions of the electricity and light-duty transportation sectors are sensitive to both changes in base renewable penetration and PHEV penetration. Increasing either of these parameters decreases the fossil fuel usage of their respective sectors, which results in GHG emissions reductions. The sensitivity due to PHEV penetration, however, is affected by the following parameters: 1) only a certain fraction of the VMT met by PHEVs is actually fueled by electricity and 2) the decrease in gasoline use for PHEVs is slightly offset by the corresponding increase in fossil fuel usage on the electric grid. In contrast, increasing the renewable electricity penetration level translates directly to decreased fossil fuel usage for the electricity sector.

When examining the sensitivity of GHG emissions from these sectors, however, the sensitivity to PHEV and renewable penetration is somewhat different. While the electric grid uses a similar

amount of fuel on a primary energy basis, it emits less GHG compared to the light-duty transportation sector. This occurs due to differences in efficiencies and the composition of the fuel stream for each sector. The electric grid uses a variety of fuel types. Primary fossil fuel types are coal and natural gas, with the latter being the dominant fuel source for California and emitting a relatively low amount of GHG per MMBTU of fuel input. Other types are also present which emit much smaller GHG amounts such as biomass and biogas, and many other types such as nuclear, wind, solar, geothermal and hydropower emit negligible GHG per unit of useful electric energy obtained. Therefore, the electric grid is able to use a larger amount of primary energy with lower GHG emissions.

The light-duty transportation sector, in contrast, uses one primary fuel source to meet essentially the entirety of the VMT demand: gasoline. Gasoline emits a higher amount of GHG per unit of useful energy obtained compared to natural gas. The conversion pathway from primary energy to useful motive energy is also generally less efficient compared to the pathway from primary energy to useful electric energy in the grid. Therefore, while the light-duty transportation sector uses a lower amount of primary energy, it exhibits higher GHG emissions.

Therefore, increasing the percentage of VMT that is met by electricity will cause a large reduction in GHG emissions for the light-duty transportation sector. However, when examining the combined transportation and electricity sectors, the increased fuel consumption placed on the grid due to PHEVs limits the net GHG reduction because the grid mix is still highly reliant on fossil fuels. This is evident from limited reductions due to PHEV penetration increases at low base renewable penetration levels. At the 10.7% base renewable penetration level, increasing the PHEV penetration level to 60% reduces the combined sector GHG emissions by 10.3%

compared to the no-PHEV case. At the 62.8% base renewable penetration level, the same increase in PHEV penetration reduces the combined sector GHG emissions by 60.3% compared to the no-PHEV case at that penetration level. Once the grid mix shifts more towards low GHG emitting sources, the GHG benefits of PHEVs are maximized.

6.1.1.3.2. Behavior of Balancing Generator Operation Metrics

The coupling of PHEVs with the electric grid also affects the operation of balancing generators which respond to ensure that the load demand is satisfied within reliability constraints. The balance generator fleet is mostly composed of load-following and peaking gas turbines fueled by natural gas. As discussed, introducing a PHEV load with smart charging acts to smooth the profile of the net load demand to the extent possible, reducing the burden on the balancing generator fleet.

6.1.1.3.2.1. Behavior of the Balance Generator Fleet Capacity Factor

The capacity factor of the balance generator fleet is the ratio of the energy obtained from all balancing generators on the grid to the amount of energy that would have been obtained if all of those generators operated at rated capacity for the entire year. This metric represents the utilization of installed resources on the electric grid. Higher capacity factors are preferable, since they represent a better return on investment. The balance generator fleet capacity factor ranges between 0 to 1, with zero indicating non-utilization of the balancing generator fleet and one indicating full utilization.

The change in the balance generator fleet capacity factor from the reference case (10.7% renewable penetration level, 0% PHEV penetration) is presented in Figure 167:

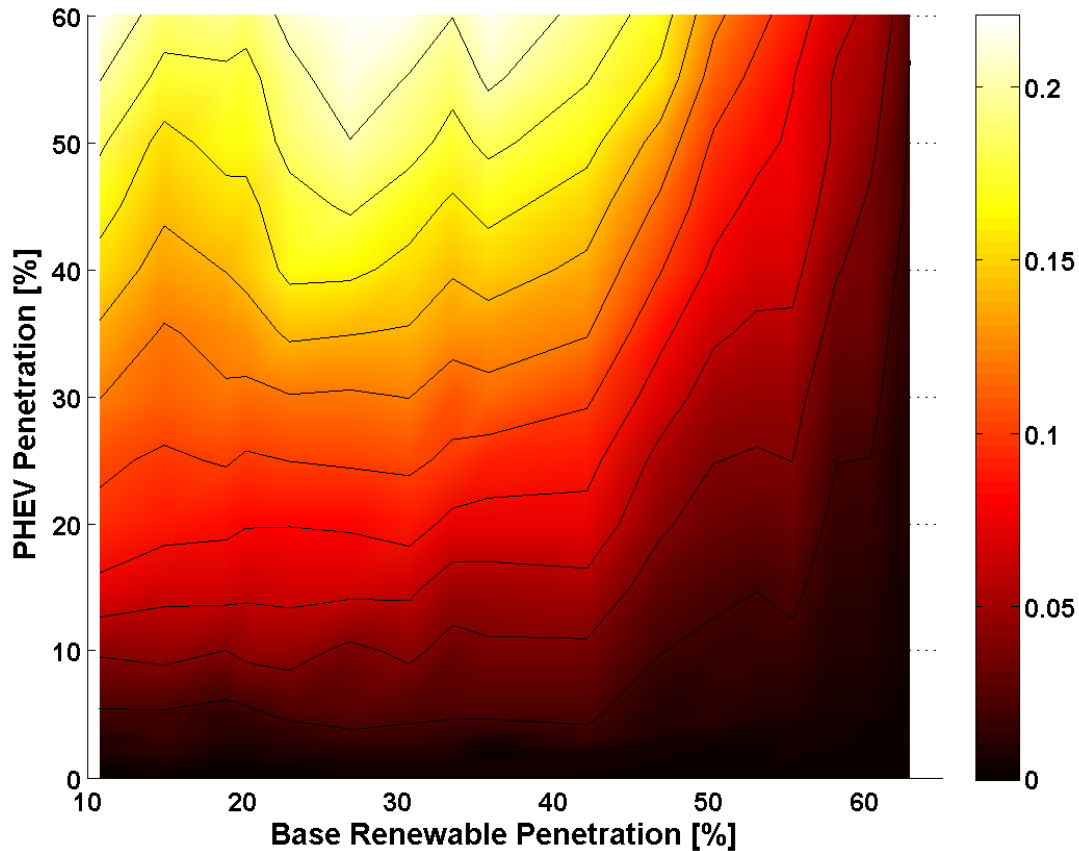


Figure 167 - Change in Balance Generator Fleet Capacity Factor from Reference

Increases in PHEV deployment and base renewable level have opposite effects on the balance generator fleet capacity factor. Increasing the base renewable penetration level generally decreases the capacity factor because wind power in California tends to peak during the nighttime hours, with limited generation occurring during the time of peak load [223]. Solar power occurs during the time of peak load, but the relatively short duration of high solar power is shorter than the duration of the combined commercial and residential load peaks. Therefore, solar power can only reduce the peak net load to a finite extent, after which the time of the peak net load shifts towards the late afternoon or early evening where solar power has limited effect, but wind generation has not yet ramped up. Therefore, to satisfy the net load demand within the

required reliability margins for all hours of the year, the balance generator fleet must still be sized to meet a net load peak that is only slightly reduced from base levels.

At the same time, however, increasing the renewable penetration level decreases the amount of energy obtained from the balancing generator fleet. With a constant base-load generator capacity and a given amount of load, increased renewable generation will cause a decrease in the energy obtained by balancing generators. With a high installed capacity but decreased output of useful energy, the capacity factor of the balancing generator fleet drops significantly.

In contrast, increasing the PHEV penetration level, serves to increase the capacity factor of the balance generator fleet compared to the no-transportation cases. This occurs due to the smoothing effect of the PHEV load with smart charging. Additionally, PHEV charging has the highest potential for load smoothing during the nighttime hours when a large amount of vehicles are plugged in [Li]. Model results show that this allows the PHEV load to be placed to complement wind power, as well as to increase the minimum load level and prevent balancing generators from having to turn off. This increases the energy obtained from these units. Since the balance generator fleet is sized to meet the peak net load which is relatively constant across base renewable penetration levels, the increased energy obtained from these generators due to load profile smoothing increases the balance generator fleet capacity factor

PHEV smart charging is able to counteract the effect of increased renewable penetration levels on the balance generator fleet capacity factor. At low renewable penetration levels, the capacity factor is able to be increased far above current levels with increased PHEV penetration.

Renewable capacities are low enough to not significantly alter the net load profile, and PHEVs are able to respond to the regular periodicity of the raw load demand by placing the charging

load during the nighttime hours. However, as the renewable penetration level increases, higher PHEV penetration levels are required to maintain balance generator capacity factors at or above current levels. Higher capacities of renewable power cause more significant distortions of the net load profile, and for the scenarios spanned in this work, the PHEV charging load starts to become too small to raise minimum load levels and increase the capacity factor. At high renewable penetration levels, the renewable capacities are too high for PHEV charging to make a significant difference in capacity factor. Overall, PHEV charging increases the utilization of the balancing generator fleet compared to the no-transportation case. However, limited flexibility and size of the load can limit its ability to do so as the renewable penetration level increases, and other complementary technologies will need to be deployed to maintain high capacity factor levels. More extensive charging infrastructure can be installed to address this to some extent; however, the charging windows at locations other than the home are short and may not provide enough flexibility for the grid or confidence for drivers, while the cost of the infrastructure will increase substantially.

6.1.1.3.2.2. Behavior of the Balancing Generator Capacity and Energy Contributions

The balancing generator fleet is composed of two classes of dynamic generators: load-followers and peaking generators. Load followers are typically more efficient combined-cycle type units that follow large variations in the bulk load demand over hourly or multi-hourly periods. Peaking generators are typically less-efficient simple-cycle units that respond to quick changes in the bulk load demand over shorter timescales. These generator types must be online for a minimum amount of time once activated due to thermal constraints, and each type has limits on their part-load operation range and how quickly they can change power output. Peaking generators generally can ramp more quickly and turn-down to lower levels, as well as be online for shorter

periods of time compared to load-followers, but they generally suffer lower efficiency and higher criteria pollutant emissions. Additionally, peaking generators tend to operate for only a small amount of time and at severe part load. This contributes to low capacity factors and causes the levelized cost of electricity from these units to be much more expensive than that from load followers.

The installation of renewables and the integration of PHEVs change the magnitudes and character of the net load profile that the balancing generator fleet must satisfy. These will change the capacities and energy contributions of each balancing generator type. The change in the capacities of load-following and peaking generators from the reference case (10.7% renewable penetration, no transportation) as a percentage of their original capacities is presented in Figure 168 and Figure 169:

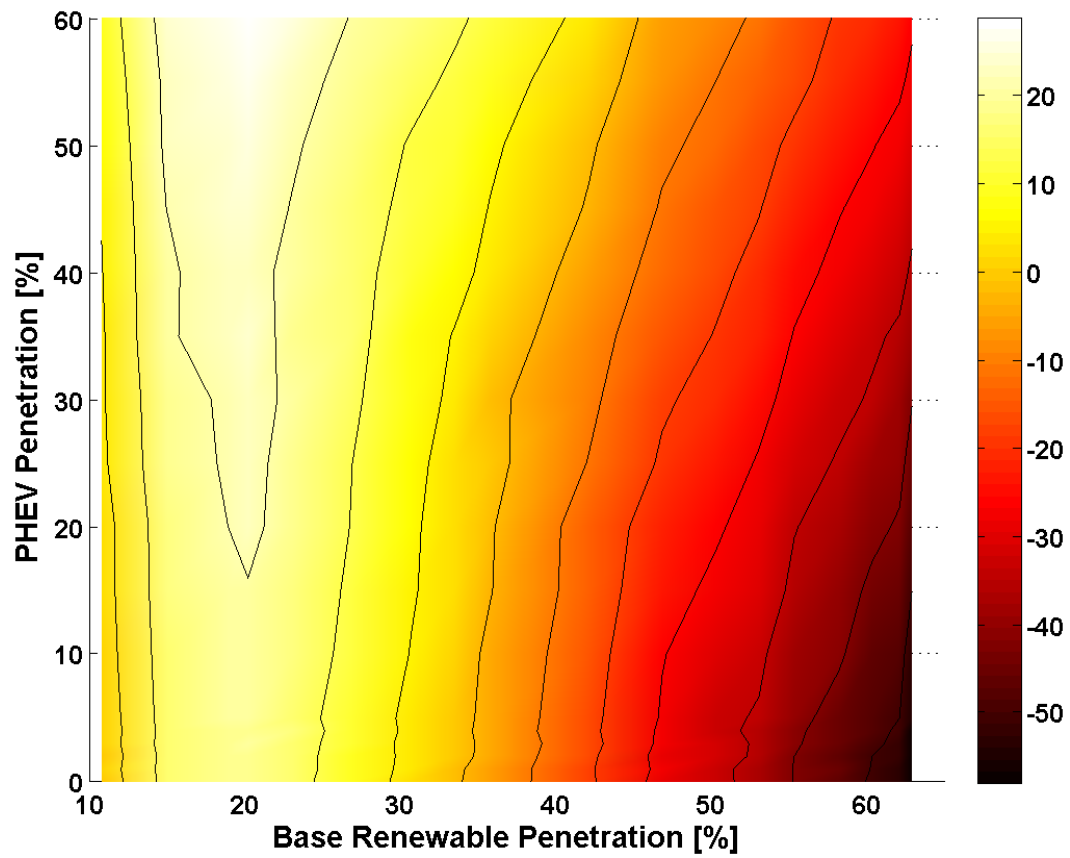


Figure 168 - Percentage Change in Load-Follower Capacity from Reference

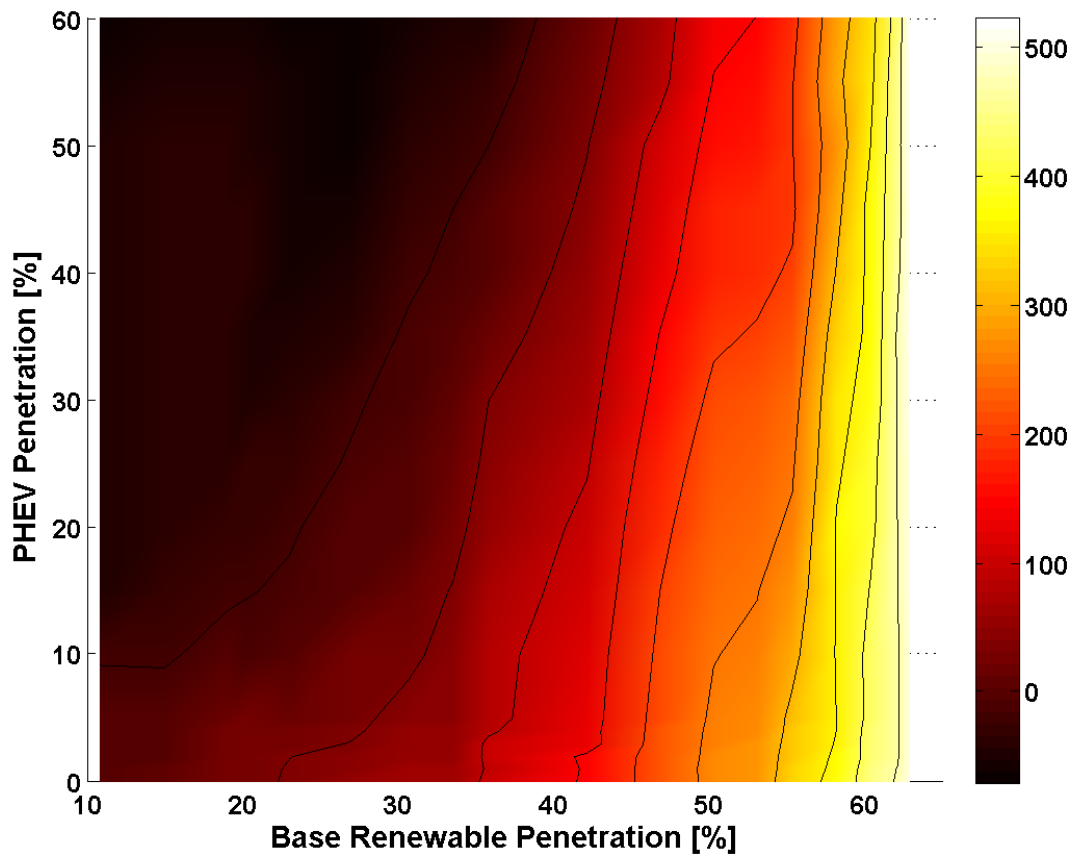


Figure 169 - Percentage Change in Peaking Generator Capacity from Reference

As the base renewable penetration level increases, the capacity of load-following generators tends to drop while the capacity of peaking generators increases significantly. The exception is for load followers at the lower renewable penetration range, which increases from that in the reference case due to the rapid decrease in coal power capacity that must be compensated for. Once the base load capacity reaches a constant level at the 33% base renewable penetration level, increasing the base renewable penetration level leads to a decrease in load following generator capacity.

Without transportation, peaking generator capacity increases by 522% at the 62.8% base renewable penetration level, while the load-following generator capacity decreases by up to 57%. This occurs due to the dynamic nature of variable renewable power sources. Solar power causes

a sharp drop in the daytime net load demand and causes sharp, but short-duration, load peaks during the mid-morning and early evening hours. These load peaks do not last long enough for load followers to warrant startup due to their designed minimum operating periods. Additionally, load followers cannot come online earlier since the net load during the daytime is too low (because of high solar power generation) for many of these units to be necessary. Wind power also decreases net load levels and removes the necessity for many load followers to be online at any given time. These results contribute to reductions in load-following capacity. Therefore, to satisfy load peaks of short duration that occur rapidly, peaking generation must be relied on to an increased extent. This can imply an increase in criteria pollutant emissions from these units due to lower efficiencies and multiple startup events.

The integration of PHEVs can somewhat counteract these trends. By smoothing the load demand, the PHEV load allows load-followers to stay online during periods of high renewable generation. This prevents the formation of short-duration load peaks and reduces the need to rely on peaking generation. At low to moderate base renewable penetration levels, smart PHEV charging is able to reduce peaking generator capacity significantly, as well as reduce the decrease in load-follower capacity. However, at high renewable penetration levels, the PHEV load is too small to counteract the effect of renewable generation.

These results are also evident from the capacity fraction of load followers in the total balance generator fleet, presented in Figure 170:

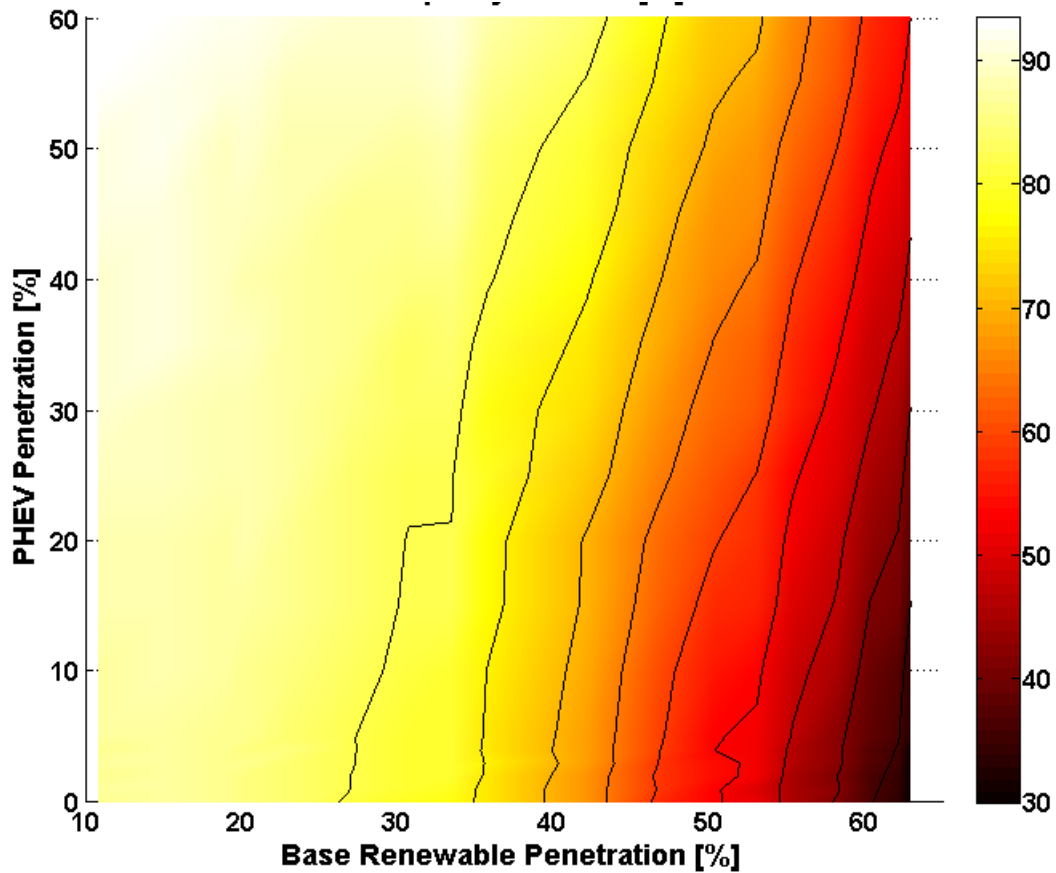


Figure 170 - Load-Following Capacity Fraction [%]

It is important to note, however, that the majority of the energy obtained from the balancing generator fleet is still sourced from load following generators. The energy contribution of load followers as a fraction of the total contribution of the balancing generator fleet is presented in Figure 171:

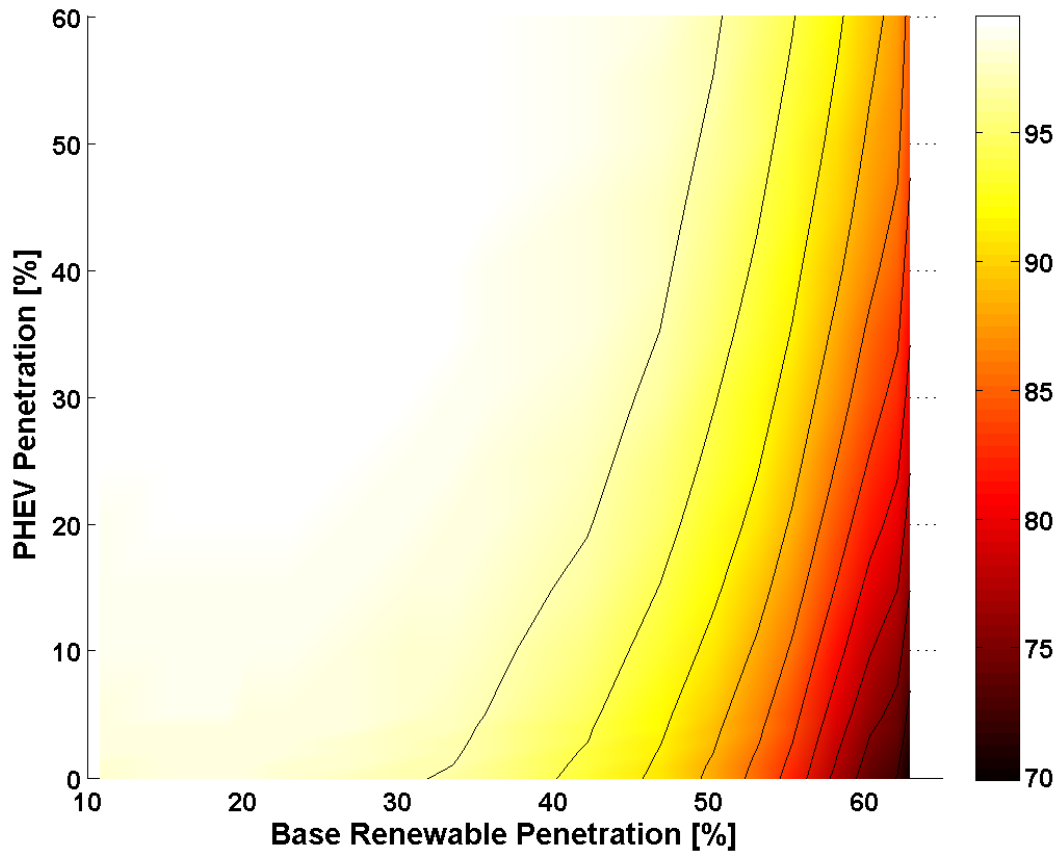


Figure 171 - Load-Following Energy Contribution Fraction [%]

The qualitative behavior of the energy contribution of load-followers is similar to that exhibited by the capacity fraction presented previously, but to a lesser magnitude. As the base renewable penetration level increases, peaking generation is relied on to a larger extent. The integration of PHEVs counteracts these trends to the extent possible.

Overall, the integration of PHEVs with smart charging can counteract the shift towards reliance on higher-polluting, less efficient, and low capacity factor peaking generation to a limited extent, provided that enough PHEVs can be deployed at a given renewable penetration level. At very high renewable penetration levels, however, PHEVs are not sufficient to maintain reliance on load-followers.

6.1.1.3.2.3. Behavior of the Balancing Generator Fleet Efficiencies

To follow the more dynamic nature of the net load demand at increased renewable penetration levels, balancing generators will be required to change their power output over larger ranges. Changing the load point of many individual generators is preferable to starting up or shutting down additional power plant units because excessive and unscheduled start-up and shut-down events contribute to wear and increased criteria pollutant emissions. Additionally, in bid-based electricity markets, unscheduled start-up or shut-down events cause increases in the price of electricity which is passed on to the utilities and the consumers [301]. Therefore, to minimize startups and shutdowns, load-following and peaking generator power outputs will be turned up or down within pollutant emissions limits and minimum efficiency limits. If the generator fleet must be turned down to a point where the units would violate emissions standards or exhibit economically prohibitive efficiencies, only then would generators be asked to shut down.

Renewables and PHEVs affect load-following and peaking generator efficiencies separately. The change in fleet efficiencies from reference case levels for these generator types is presented in Figure 172 and Figure 173:

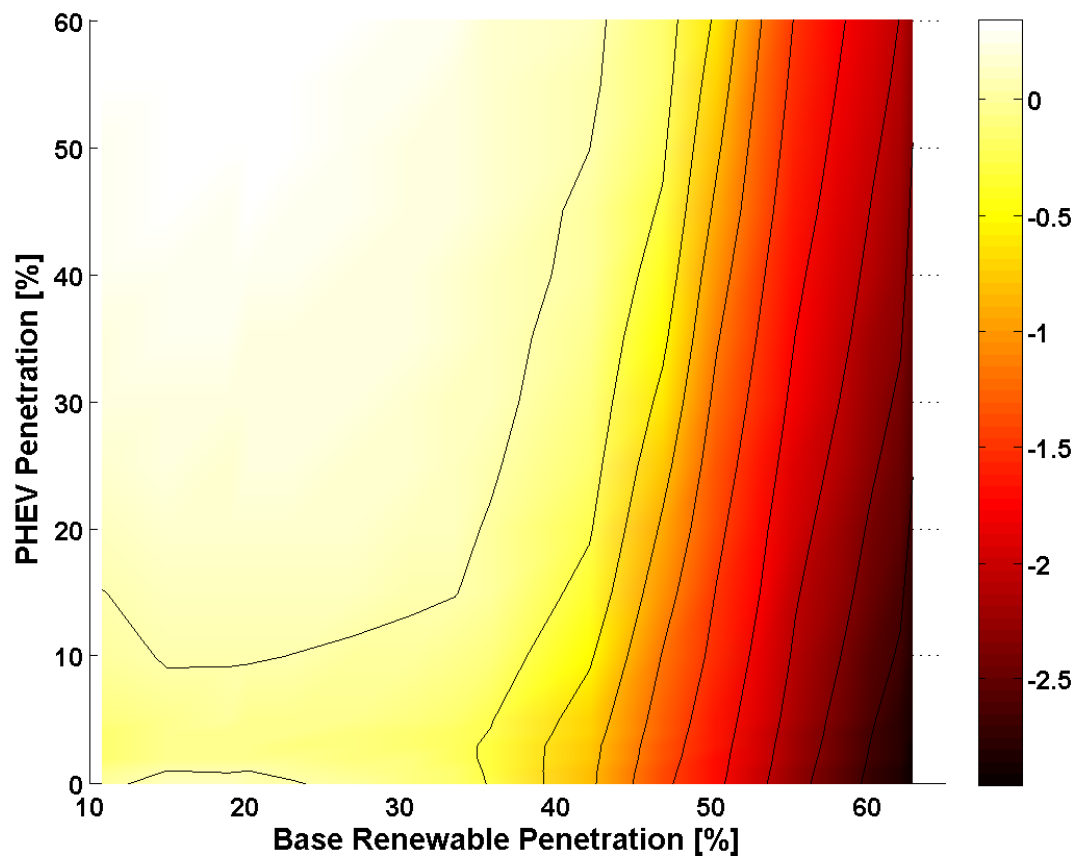


Figure 172 - Change in Load-Following Generator Efficiency from Reference [%]

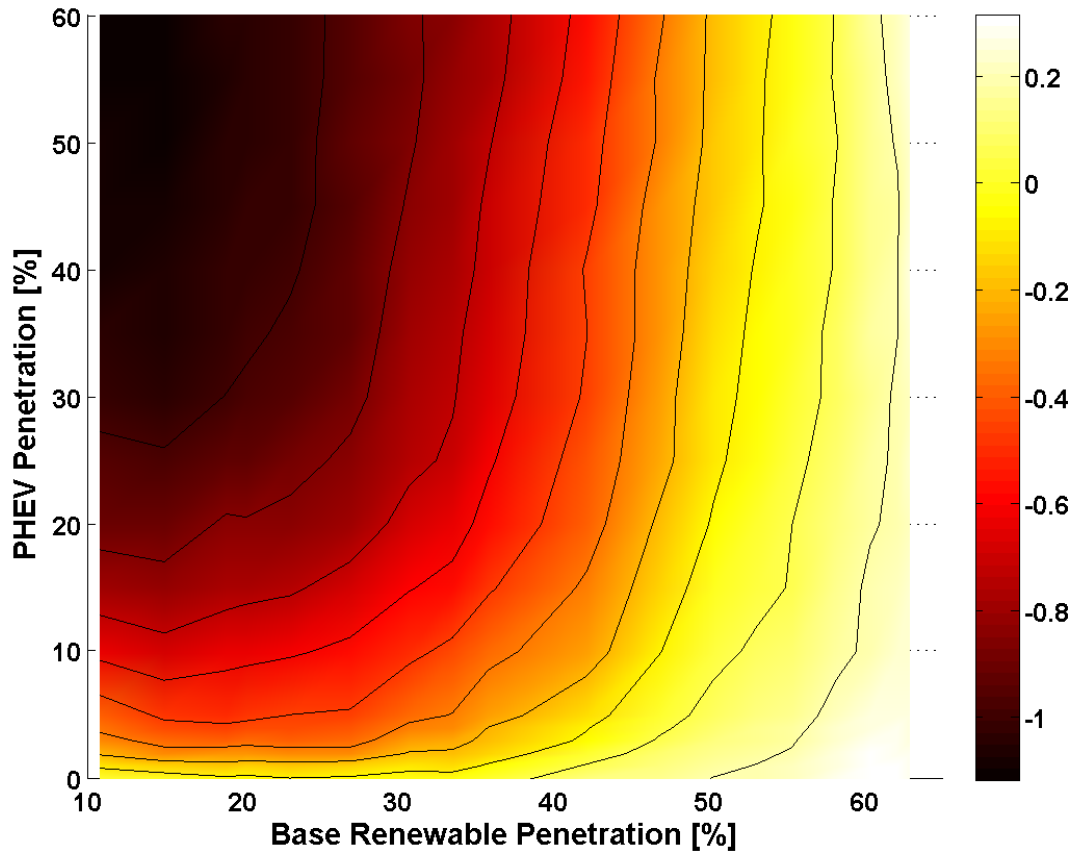


Figure 173 - Change in Peaking Generator Efficiency from Reference [%]

As the base renewable penetration level increases without the effects of transportation, the efficiency of peaking generators tends to remain relatively constant, while that of load-followers tends to drop noticeably.

Load-following generators suffer decreases in efficiency due to being forced to operate at severe part-load conditions as renewable power is increased. For low to moderate base renewable penetration levels, the change is very slight since the capacity of load-followers are still high enough such that units can be shut down to meet the load during periods of high renewable generation. This allows remaining units to operate near design power output and therefore at high efficiency. Additionally, renewable generation is not large enough to cause severe distortion of the net load profile at these penetration levels. At higher base renewable penetration levels,

however, renewable generation is so large that for most of the hours out of the year, only a handful of load-following generators are online. These load-followers cannot shut down since ancillary service requirements such as the provision of regulation and spinning reserve require controllable, responsive generation to be online at all times. Therefore, with a decreased ability to start up or shut down generators, load followers must turn down towards minimum part-load conditions often to accommodate renewable generation and prevent curtailment.

Peaking generator efficiency is not significantly affected by renewable generation, since these units operate at severe part-load often in the reference case already. Since these generators do not provide regulation or spinning reserve, more flexibility for shutting down or starting up generators is required. Additionally, at increased base renewable penetration levels, peaking generators begin to dominate the balance generator fleet, causing many to be online during certain periods of the year. Therefore, the peaking generator fleet can exercise this flexibility to maintain efficiencies at reasonable levels.

The integration of PHEVs counteract both of these trends by maintaining the efficiency of load followers but decreasing that of peaking generators. By smoothing the load in the manner described throughout this study, smart PHEV charging allows load-followers to exhibit more steady operation. Likewise, the increase in the magnitude of the load demand allows many units to remain online during most of the hours of the year. This flexibility allows the load-following fleet to refrain from operating at severe part load conditions and maintain high efficiencies. The peaking generator fleet efficiency, by contrast, decreases since these units are not as heavily relied on to meet the load. This renders a lower amount of peaking generator units to be online at any given time, reducing flexibility and causing these units to operate at severe part load.

Additionally, peaking units are only called upon to meet milder variations in the bulk load demand in these cases; therefore, these units will come online at part load. This benefit is strongest at low to moderate base renewable penetration levels, but is mitigated at high base renewable penetration levels since the PHEV load becomes too small relative to the installed renewable capacities to provide enough smoothing of the net load profile.

Overall, PHEVs can improve the operation of the balancing generator fleet by mitigating many of the effects of increased renewable generation. PHEV integration helps to maintain high efficiencies in load-following generators which provide most of the energy obtained from the fleet. Similar to the other benefits, more PHEVs are required to provide benefits as the base renewable penetration level increases. The ability to provide these benefits becomes nullified at high base renewable penetration levels.

6.1.1.3.2.4. Behavior of the Balancing Generator Ramp Rates

Without the effects of variable renewable power, the profile of the load demand that balancing generators must satisfy is predictable in terms of its shape and magnitude on a day-to-day, hour-to-hour timescale. This load profile exhibits the largest variations on a daily timescale, and since it is the aggregate of a large amount of individual loads, it does not tend to change in very large amounts from hour-to-hour. The California Independent System Operator (CAISO), which is the balancing authority for the vast majority of the state's load, relies on this predictability to schedule the operation of power plants and operate the electricity market.

However, with an increased penetration of variable renewable power, the net load profile becomes less predictable and subject to larger changes over shorter timescales. Balancing generators have physical constraints on power ramp up and ramp down rates. The change in the

average ramp rates of the entire balancing generator fleet from that in the reference case is presented in Figure 174 for up ramp rates and in Figure 175 for down ramp rates:

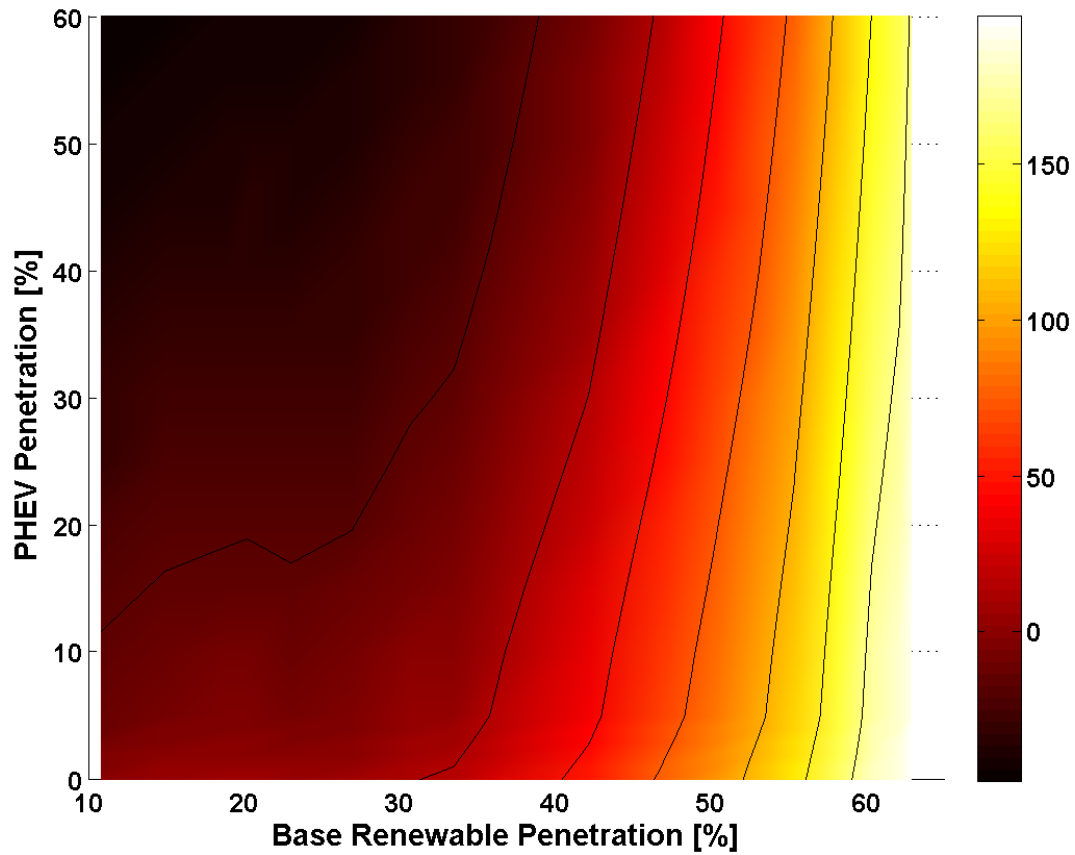


Figure 174 - Percentage Change in Average Balance Generator Fleet Ramp Rate Up from Reference

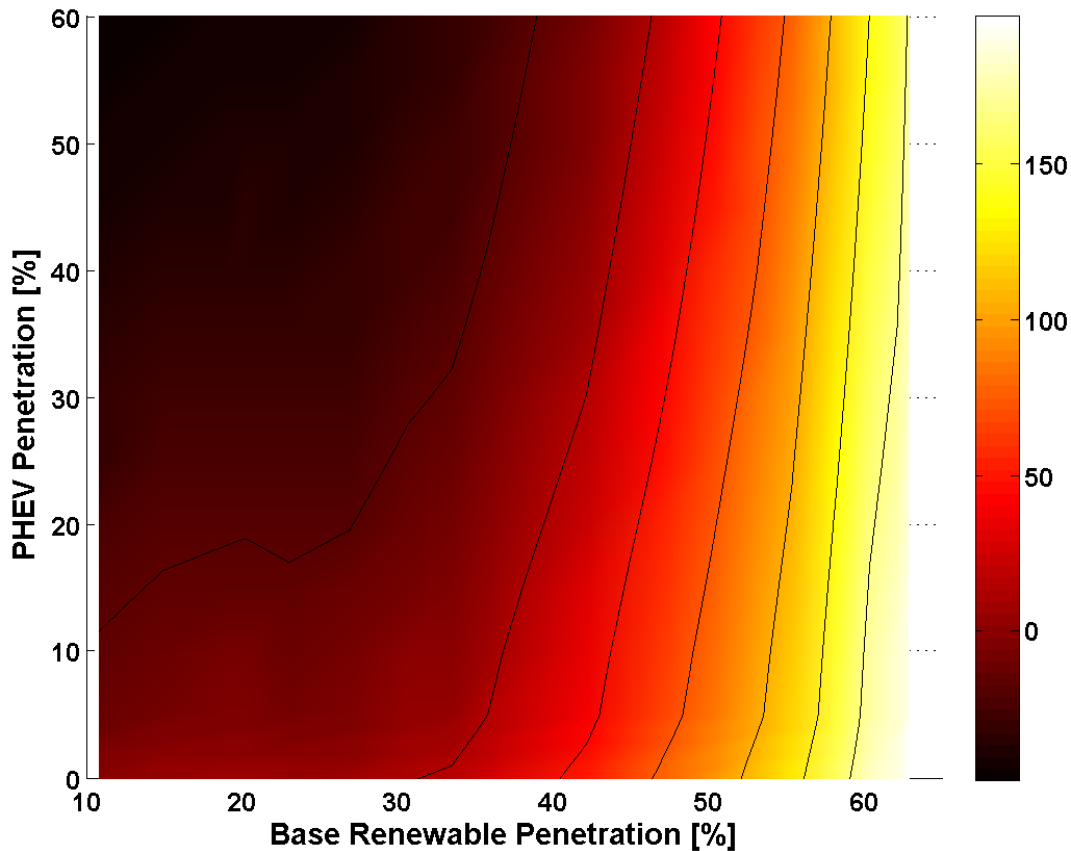


Figure 175 - Percentage Change in Average Balance Generator Fleet Ramp Rate Down from Reference

The introduction of variable renewable power serves to increase the magnitude of the up and down ramp rates of the balancing generator fleet up to a point, after which further increases in the base renewable penetration level causes these ramp rates to decrease. The initial increase occurs due to the peak-dominated and dynamic nature of wind and solar power. Solar power tends to cause large down ramp rates for the balancing generator fleet during the late morning hours and large up ramp rates during the early evening hours. Wind power tends to decrease the minimum load during the nighttime hours, causing large down ramp rates during the late evening and large up ramp rates during the mid to late morning hours. Additionally, both wind and solar are often subject to short-term intermittencies that cause increased up and down ramp rates in the balance generator fleet.

After a certain point, however, the renewable capacities become so large that the balancing generator fleet is pushed to its minimum operating level and renewable power is curtailed in large amounts during certain hours. Meeting the load demand in this manner then becomes a matter of renewable curtailment, and the operating point of the balancing generator fleet does not change. Many of these hours occur at higher renewable penetration levels, causing the average ramp rates to decrease back to normal levels. With further increases in the renewable penetration level beyond the range displayed here, ramp rates would actually decrease below current levels as the majority of the hours out of the year start to exhibit this characteristic.

The use of PHEVs with smart charging once again counteracts the effect of introducing variable renewable power by decreasing the average ramp rates of the balancing generator fleet. While the dispatch of PHEV loads cannot reduce the peak load magnitudes, it can increase the minimum load points, decreasing the difference between these points and therefore decreasing the average ramp rates. Specifically, PHEVs can introduce load during periods of high renewable generation to buffer the dynamics of renewable power from affecting the balance generator fleet.

Similar to other results, to provide significant benefits for maintaining ramp rates at low levels, a large amount of PHEVs must be deployed even at low base renewable penetration levels. Even more PHEVs must be deployed as the base renewable penetration level increases. This occurs due to the fact that not only is the energy of the PHEV load relatively small compared to that of the load demand or renewable generation, its capacity is also small. At a 60% PHEV penetration with Level 1 home charging, the “peak” load that the transportation sector can theoretically introduce if all PHEVs were plugged in during an hour is about 18 GW. In practice, due to the fact that not all cars can be plugged in at the same time and that individual charging schedules

will vary, the maximum load of PHEVs in the 60% case is about 11.4 GW. Additionally, a lower amount of cars are plugged in during the daytime, limiting the ability of the system to provide benefits.

Overall, PHEVs with smart charging can counter the required increases in ramping capability brought about by renewable power. But, due to the low capacity of the charging load relative to the renewable capacity, and varying flexibility throughout the day, a large vehicle penetration is required to provide significant benefits, especially as the base renewable penetration level is increased.

6.1.1.3.2.5. Behavior of the Number of Balancing Generator Start-Up Events

The increasingly dynamic nature of the net load profile due to renewable generation also has implications for the number of start-up events that balancing generators must undergo. Large increases in the bulk load demand due to sharp decreases in renewable generation require additional generators to come online to satisfy the load demand and meet ancillary service requirements. The change in the number of start-up events for a typical balancing generator from that of the reference case is presented as a percentage in Figure 176.

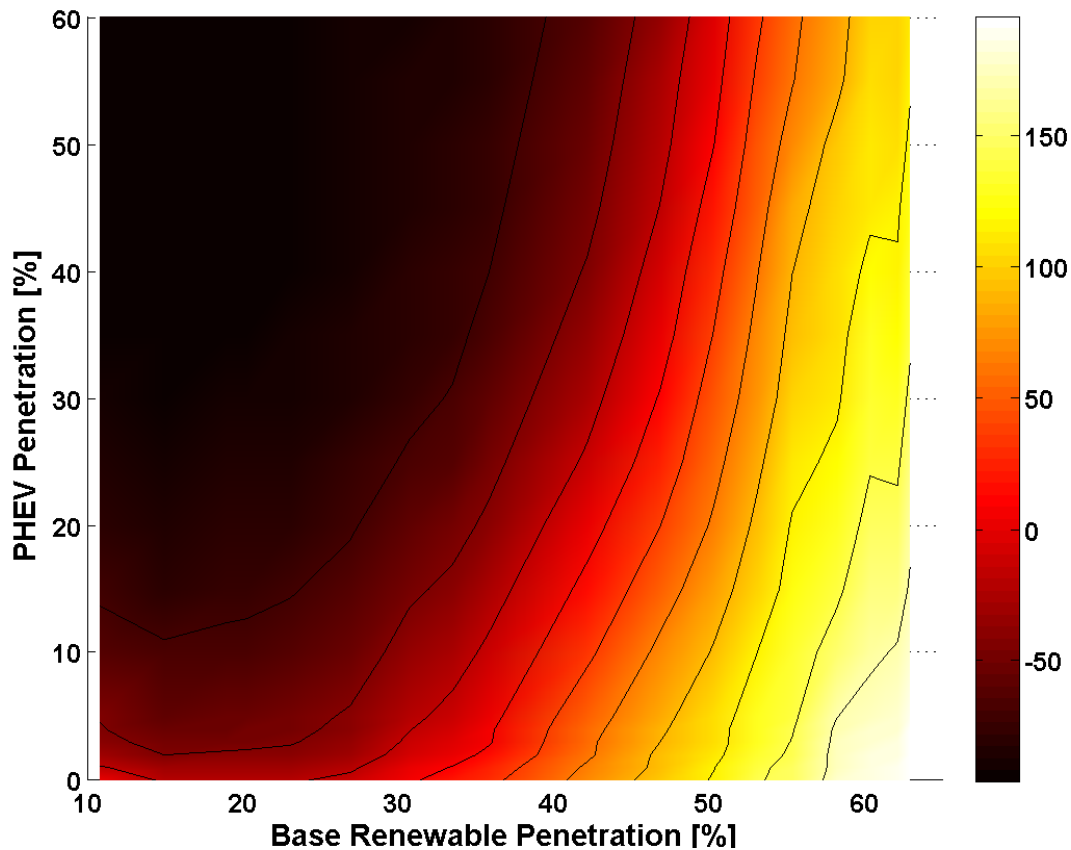


Figure 176 - Percentage Change in Average Balancing Generator Start-Up Events per Generator from Reference

As expected, the number of balancing generator fleet starts increases with base renewable penetration. By the 62.8% base renewable penetration level, the number of start-up events increases by 193.7% in the case without transportation integration. Increasing the base renewable penetration introduces larger and more frequent short-term fluctuations in the net load demand which contributes to more generator starts, primarily in peaking generators.

It is important to note, however, that the number of balance generator starts does not necessarily increase uniformly with base renewable penetration level, and that it is dependent strongly on the mix of renewable resources used to meet that penetration. Eichman [43] found that the average number of yearly start-up events for a typical generator tended to increase up to a certain point.

After this point, the number of starts would decrease due to the balancing generator fleet being pushed to its minimum operating level for longer periods of time. Adjusting curtailment became the dominant method for following the load demand and balancing generators did not have to start up very often. Depending on the renewable mix used, this point occurred at different points in the renewable penetration range, with more peak-dominated renewables reaching this point earlier and vice versa. This trend still holds true in this analysis. The key difference is that the renewable mix used in this study contains a diverse array of resource types, varying from base-load to peak-dominated operating characteristics. Synergies in this mix causes the point where excessive curtailment becomes prevalent for most of the hours out of the year to occur at a later base renewable penetration than that reached here. If the base renewable penetration level range is extended, the number of starts per balancing generator would drop off sharply.

Similar to other aspects of balancing generator operation, the introduction of PHEVs with smart charging onto the electric grid counteracts the effect of increasing renewable capacity on the number of balancing generator starts. By introducing charging load during periods when the net load after renewables is low and smoothing the overall net load profile, PHEVs allow balancing generators to stay online during periods when renewable generation is very high. Therefore, when renewable generation subsides at a later point in time, these generators do not have to undergo a start-up event. This is most prevalent at low baseline renewable penetration levels, where the PHEV charging load cuts the number of start-up events per generator significantly. With 60% PHEVs, the number of generator starts is reduced by almost 90% for base renewable penetration levels below 20%. As the base renewable penetration level increases, PHEVs are able to maintain the current number of generator starts over a wide range, but require large

amounts of PHEVs to do so. At the highest base renewable penetration levels, the PHEV charging load still reduces start up events, but is limited in its ability to do so.

6.1.1.3.3. Behavior of the Levelized Cost of Electricity from Base

From the discussion thus far, the introduction of PHEVs onto the electric grid affects the design and operation of load-balancing resources on the grid, as well as the utilization of installed renewable resources in the system. All of these aspects have implications for affecting the levelized cost of electricity that is passed down to the consumer.

It is important to note that in this analysis, the levelized cost of electricity represents the cost of a unit of electric energy from the system due to costs associated with the design and operation of electric grid resources. This includes that associated with base load and balancing generators, fuel usage, renewable installations, transmission construction and transmission/distribution losses. This does not include the cost of components of the PHEV electric charging infrastructure such as smart chargers, distribution infrastructure upgrades, and communications. Therefore, in this analysis, the change in the levelized cost of electricity represents the value of introducing PHEVs with smart charging onto the electric grid within the context of increasing the supply of renewable energy in the primary energy mix. This value will have to be weighed against infrastructure costs to determine whether it makes economic sense to use this strategy to support renewables, or what factors would need to change in order for it to become economically viable.

The change in the levelized cost of electricity from that in the case without any transportation interface is presented in Figure 177. Note that this does not represent a change from the reference case value, rather, it represents a change from the value at each base renewable penetration level without any PHEV penetration. For reference, the progression of the levelized cost of electricity in the no transportation case in absolute terms is presented in Figure 178:

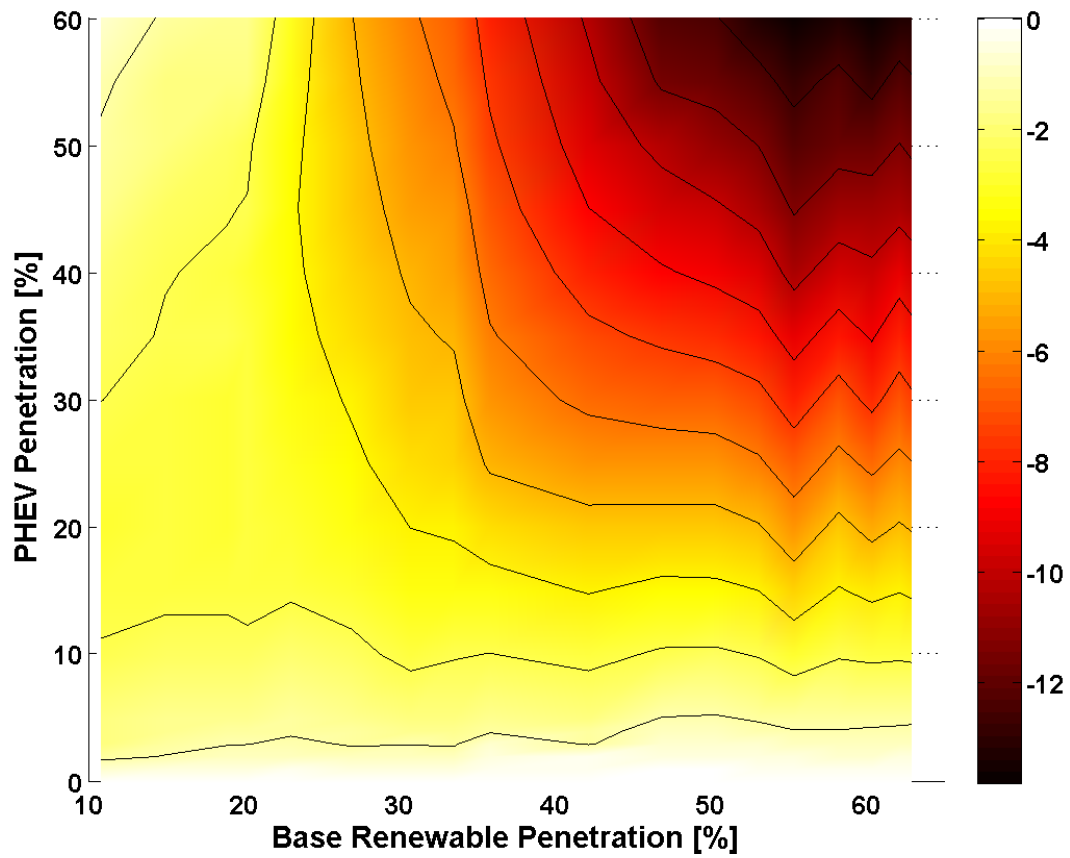


Figure 177 - Change in the Levelized Cost of Electricity from the No-Transportation Cases (Percentage of Base)

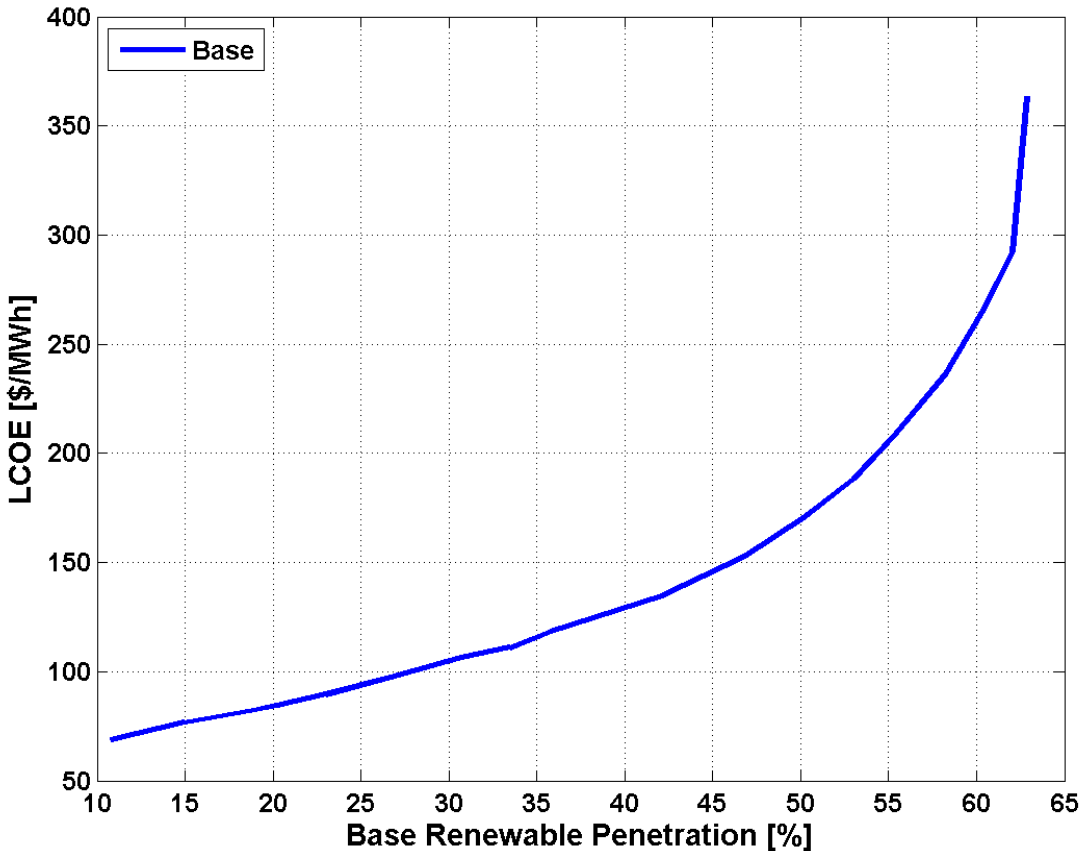


Figure 178 - Progression of Levelized Cost of Electricity in Base Case

Compared to the case without any transportation interface, the introduction of PHEVs with smart charging serves to decrease the levelized cost of electricity from the standpoint of the grid. The economic benefit of introducing PHEVs is dependent on base renewable penetration level and the amount of PHEVs deployed, as expected. Contribution to increased balance generator capacity factors allow higher utilization of installed equipment, indicating a better return on investment per unit of capacity installed. Reducing curtailment at the higher end increases the utilization of renewable resources, also indicating better returns on investment for these resources. Partially counteracting the decrease in load-following generator efficiency due to renewable integration as well as allowing more renewable energy to contribute to the load

demand decreases fuel usage. Reducing ramp rates and start-up events decrease the wear and degradation of balancing generators, reducing costs as well.

At low base renewable penetration levels, the levelized cost of electricity decreases by about 3.0% with a 20% PHEV penetration level, after which the benefit is not as strong with higher PHEV penetration levels. In these regions, renewable capacities are low and do not cause operational issues for the system. PHEV charging therefore acts to improve the operating characteristics of the current system, which in this context has limited value. Recall that PHEV charging increases the energy of the electric load, which increases electricity sector fuel consumption. Additionally, at low base renewable penetration levels, the additional load demand must be met by the installation of new generators which carry high capital costs. With more PHEVs, the increase in the load demand is higher, incrementally offsetting the value of improving the operational characteristics of the current system. Therefore, deploying too many PHEVs at too low of a renewable penetration level may not provide much value to the electric grid.

At moderate base renewable penetration levels (30-40%), renewable capacities are high enough to alter the design and operation of load-balancing resources. The PHEV load therefore acts to counter this alteration by responding to renewable generation directly. By mitigating the decrease in capacity factor due to renewables alone, and preventing renewable curtailment, PHEVs with smart charging provide value to the system. Additionally, since renewable generation is able to decrease the net load demand to noticeable extents, the load due to PHEVs is often met by renewable generation. This reduces the need for installing additional balancing generator capacity and the use of additional fuel to satisfy the PHEV load. With these costs

reduced, the operational benefits due to PHEVs are able to provide their full value to the system, which increases as more PHEVs are added. Reductions up to 8.5% in the levelized cost of electricity compared to the no-transportation case are garnered with a large PHEV penetration level.

At high base renewable penetration levels, renewable generation significantly changes the design and operation of load-balancing resources. The increasingly dynamic nature of the net load demand causes balance generators to undergo stress and become severely underutilized. The very large capacity of renewables exceeds the magnitude of the portion of the load demand that is not met by base-load generators, causing large amounts of renewable curtailment and therefore underutilization. Combined with high capital costs for most renewable resource types, this contributes to sharp increases in the levelized cost of electricity in the no-transportation case. The PHEV load acts to increase the utilization of the balance generator fleet, but more importantly acts to increase the utilization of energy obtained from renewable resources. The latter provides the most value. Renewable resources are newly installed and carry high capital costs; therefore the cost of electricity from these resources is highly sensitive to utilization. Curtailment of renewable power significantly decreases the return on investment. In contrast, while some additional balancing generator capacity may need to be installed, much of this capacity is already in place in California and the investment in these resources has already been partially repaid. Therefore, PHEV charging provides the most value by increasing the utilization of installed renewable resources, with more PHEVs providing greater benefits. With a 60% PHEV penetration level, decreases in the levelized cost of electricity of up to 13.4% are achieved compared to the no-transportation case.

In absolute savings, the decrease in the levelized cost of electricity from the no-transportation cases is presented in Figure 179:

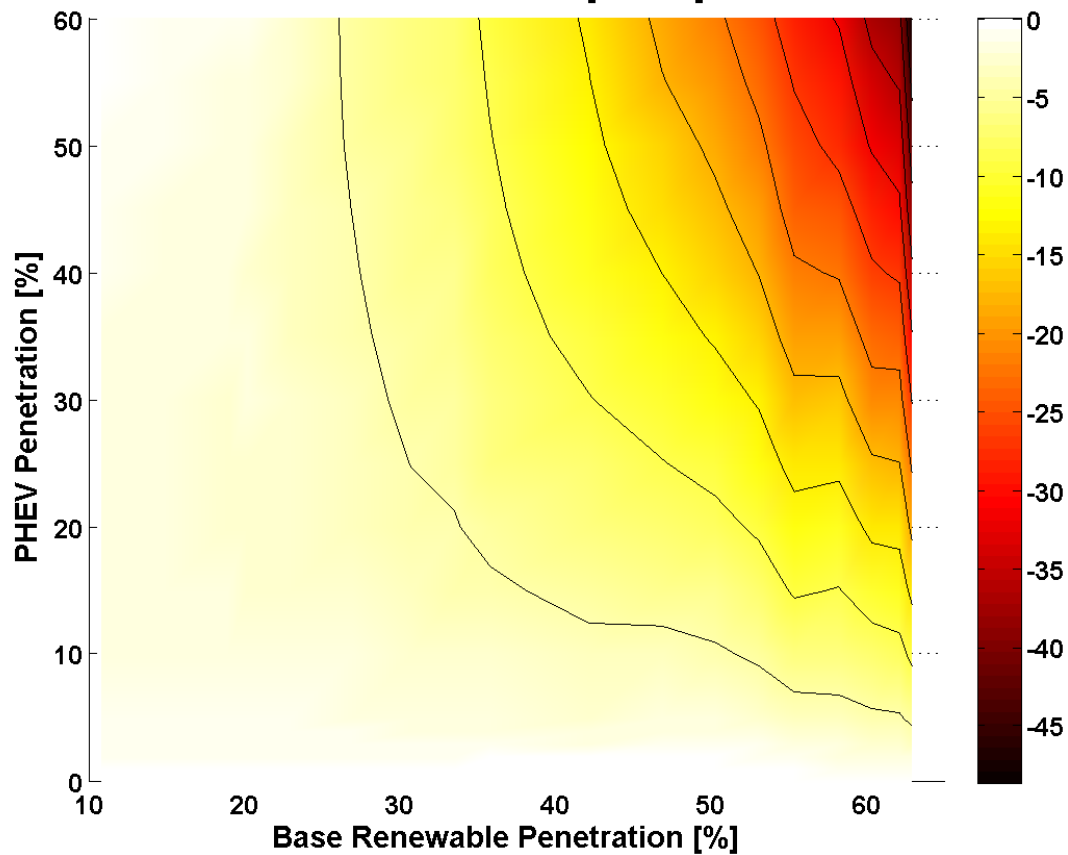


Figure 179 - Change in the Levelized Cost of Electricity from the No-Transportation Cases (Absolute)

Keep in mind, however, that the levelized cost of electricity in the case without any transportation interface increases mostly linearly at first, then exponentially as the base renewable penetration level increases. Therefore, while reduction in the levelized cost of electricity from base increases with more PHEVs at high renewable penetration levels, the base value has increased as well. The trends behind this behavior are discussed by Eichman [43].

In this context, it is also important to highlight the need for smart charging in order to maximize the synergies between PHEV and renewable integration. A comparison of the change in the

levelized cost of electricity from the base case for an immediate charging (ASAP) strategy is compared with that of smart charging for different renewable penetrations in Figure 180:

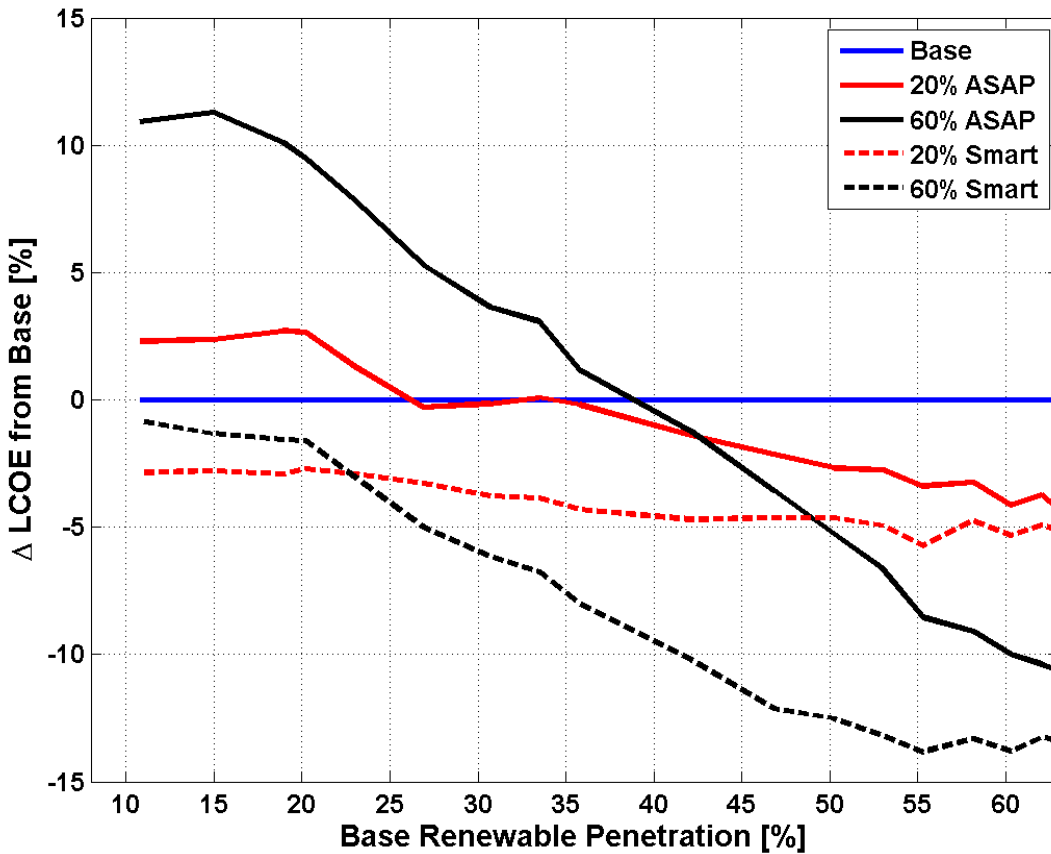


Figure 180 - Change in LCOE from Base: ASAP vs. Smart Charging

The ASAP charging strategy represents the case when PHEVs begin charging as soon as they are plugged in by the consumer upon arrival at their residence. In California, this results in a large charging load between 5 pm to 8 pm, slightly decreased load until 12 midnight due to a lower amount of cars arriving home and earlier vehicles reaching close to a full charge. Low charging loads are present at all other times of the day due to the travel patterns of motorists in the state.

With this charging scheme, however, the peak charging load is placed during the time when the stationary electric load demand is very high due to the residential load peak. In California

specifically, this also corresponds to the time period where solar power is starting to decrease sharply but wind power has not yet started to ramp up. Therefore, to serve the majority of the charging load, the electric grid must rely more heavily on peaking generators which have lower efficiencies and higher criteria pollutant emissions. Since with ASAP charging, PHEV integration tends to increase the daily peak load, this also starts to require the installation of new peaking generators. This also leads to a decrease in the capacity factor of the balancing generator fleet.

These factors combined render the use of ASAP charging to cause an increase in the cost of electricity over most the base renewable penetration range. ASAP charging only starts to show decreases in the LCOE at high renewable penetration levels, since renewable capacities are so large that even a low renewable generation causes curtailment that the PHEV load mitigates.

This is in stark contrast to the use of smart charging, which acts to smooth the load demand, increase the capacity factor of the balancing generator fleet and allowing reliance on more efficient generator types. This behavior allows the cost of electricity to decrease compared to the base case values at each base renewable penetration level.

6.1.1.4. Summary and Conclusions

6.1.1.4.1. Summary

This study analyzed of the effectiveness of PHEVs with smart charging with respect to two areas.

- First, their role in supporting the achievement of holistic GHG reduction, fossil fuel use, and sustainability goals with specific attention to aiding the increased integration of renewable resources onto the electric grid was examined.

- Second, an examination of the effect of plug-in hybrid electric vehicles (PHEVs) with smart charging on the design and operation of load-balancing resources on the electric grid in the context of increased variable renewable generation was performed. This impact was measured in terms of effects on the capacity factor, efficiency, ramp rates, and number of generator starts for the balancing generator fleet.

The energy system of the state of California was used as the primary example of a system with large electric load and vehicle-miles-traveled demands.

6.1.1.4.2. Conclusions

The key conclusions of this study are as follows:

1. The integration of PHEVs with smart charging can increase the utilization of installed renewable resources, but only under certain conditions. Since wind and solar power resources are peak-dominated, high capacities of these resources need to be installed to increase the renewable penetration level. At a certain point, capacities will become high enough to warrant curtailment of renewable generation. The introduction of the PHEV charging load allows the system to alleviate the effects of curtailment by placing load during periods of high renewable generation to some extent. This effect has benefits for increasing the actual renewable penetration level and combined renewable fractions. To obtain this benefit, however, the size and flexibility of the PHEV load must complement the behavior of renewable generation.

2. The electrification of the light-duty transportation sector through the use of PHEVs can contribute to reductions in combined sector fuel usage and GHG emissions, but the extent of these benefits depends on the progress of the grid towards reaching renewable energy procurement goals. The use of PHEVs in the light-duty transportation sector reduces

fuel use and GHG emissions of the sector due to increased vehicle efficiency pathways and reductions in the amount of vehicle-miles-traveled fueled by gasoline. However, these reductions are slightly offset due to increasing the load demand on the electric grid. When renewable penetration levels are low, the electric grid relies heavily on fossil fuels that emit GHG and other non-renewable resources. Therefore, introducing PHEVs onto the grid when renewable penetrations are low causes an increase in the GHG emissions and fuel use of the electricity sector, slightly offsetting reductions in the transportation sector. Introducing too many PHEVs too early can exacerbate this effect.

3. In the holistic scope, environmental benefits due to the use of PHEVs are maximized when synergies between the deployment of these vehicles and that of renewable power generation are considered. Benefits for GHG emissions, fuel use, and renewable energy utilization are most significant when both PHEVs and renewable resources on the grid were deployed. This highlights the importance of considering the interaction between sustainability measures in different sectors in a holistic sense.

4. The integration of PHEVs with smart charging can counteract many of the operational problems that variable renewable power has on the electric grid, but becomes limited in its ability to do so at high renewable penetration levels due to load size and flexibility constraints. Introducing the PHEV load increases the flexible portion of the load demand. The use of PHEVs with smart charging increases the capacity factor of the balance generator fleet, maintains the efficiency of load-following generators, reduces the reliance on peaking generators, and decreases generator ramp rates and start-up events compared to the cases without any transportation interface. This increases the utilization and efficiency of the balancing

generator fleet while minimizing criteria pollutant emissions and generator wear. At high renewable penetration levels, however, the magnitude of the PHEV load alone becomes too small to mitigate the operational impacts of large renewable capacities. Additionally, the variable flexibility of PHEVs throughout the day due to changes in the amount of vehicles plugged into the grid renders PHEV charging limited in its ability to complement solar power with a home charging infrastructure. More extensive charging infrastructure can be installed to address this to some extent, but the charging window at locations other than the home are short and may not provide enough flexibility, while the cost of the infrastructure will increase substantially.

5. The design and operational benefits of PHEVs provide cost savings for the electricity sector, but these savings will need to be weighed against the cost of installing the infrastructure necessary to provide such benefits. For all PHEV penetration and renewable penetration level combinations considered in this analysis, the levelized cost of electricity was found to decrease compared to the cases without any transportation interface. Larger decreases were garnered at higher renewable penetration levels with more PHEVs deployed on the road.

6. The use of smart charging is important for providing benefits for the design and operation of load-balancing resources on the electric grid. Although only displayed for the levelized cost of electricity, the use of ASAP charging did not allow the PHEV charging load to complement the net load profile with increased renewable penetration levels. Without smart charging, PHEVs can potentially be detrimental to the system in terms of operation and cost, highlighting the importance of adequate communications and control infrastructures.

Overall, this study signifies two key points:

- PHEVs with smart charging can contribute towards meeting holistic environmental goals, but the simultaneous implementation of other complementary technologies will likely be required to actually meet those goals.
- PHEVs with smart charging can be a beneficial asset for allowing the electric grid to accommodate increased variable renewable generation.

Similar to other complementary technologies, the use of PHEVs has advantages and disadvantages. Limitations exist on the ability of PHEV smart charging that prevent its use from enabling the electricity and light-duty transportation sectors to meet the entirety of their holistic environmental goals. Additionally, the use of PHEV smart charging alone is unable to mitigate all of the impacts of introducing variable renewable power on the design and operation of load balancing resources on the grid. Therefore, other technologies such as demand response, energy storage, and other dispatchable loads will likely be required in tandem to make up the difference, and coordination between these technologies will be critical. Since the light-duty transportation sector has typically relied on a single paradigm, however, the advantages and disadvantages of PHEVs in this context will need to be compared against other technologies such as hydrogen fuel-cell vehicles, on a consistent basis. The use of other PEV types, such as battery-electric vehicles (BEVs) and PHEVs with a different chemical fuel such as hydrogen will also need to be considered.

6.1.2. Battery Electric Vehicles (BEVs) and Fuel Cell Vehicles (FCVs) on the Electric Grid

6.1.2.1. Literature Review and Background

The importance of reducing greenhouse gas (GHG) emissions has been recognized by a number of government agencies. California, with the initiatives announced under the AB32 legislation [22], is the first entity in the United States to set a target for the long-term reduction of GHG emissions. Current targets aim for an 80% reduction below 1990 levels by the year 2050. These measures are being used as a model for legislation being passed in other areas, such as renewable portfolio standards [24, 302, 303] and zero emissions vehicle targets [304]. The combined energy sectors of electricity and light-duty transportation constitute approximately 50% of total GHG emissions in California [305], leading much of the policy initiatives in support of AB32 goals to be focused in these areas.

The development of these policies, however, has not historically accounted for the effect of potentially synergistic interactions that may be present between decarbonizing technologies on the electric grid (such as renewables) and the transportation sector such as battery electric (BEVs) and fuel cell vehicles (FCVs). For example, the progression of renewable portfolio standard goals was set independently of that for the zero emission vehicle mandates.

Characterization of the effectiveness and feasibility of technology options have typically been evaluated either by focusing on single sector impacts [170, 306-309], using static assumptions for the behavior of co-dependent sectors [158, 287, 310-319], or without the context of integrated constraints on grid operation and transportation demands [307, 320, 321]. Other studies have considered some degree of interaction, but for specific deployment scenarios [179, 193]. This has occurred due to a lack of adequate holistic analyses that captures the spectrum of

detailed constraints, technology characteristics, and key interactions. An overview of the transportation sector components that produce significant electric loads, the factors that shape the temporal character of those loads, and potentially synergistic interactions between the electricity and transportation sectors are presented in Table 58. Hydrogen production methods other than electrolysis are not included since these do not produce a large electric load. Shaping factors determine the temporal shape and constrain the dispatchability of the associated loads, giving each load type a unique character and interaction with the grid. BEV charging can range from being either non-dispatchable (immediate charging) to highly dispatchable (grid-responsive charging). Central electrolysis can freely shape its load profile given that storage capacities are not violated. Hydrogen dispensing is tied with consumer refueling patterns, and distribution is tied with supply management, granting only limited dispatchability. The listed potential synergies can have different effects - (E): Emissions benefit, (C): Cost Benefit, (O): Operational Benefit.

Table 58 - Overview of transportation sector components interacting with the electric grid.

<u>Major Load-Producing Transportation Components</u>	<u>Dispatchability</u>	<u>Electric Load Shaping Factors and Constraints</u>
BEV Charging 	None to High	• Charging Location Availability • Charging Power Level • Consumer Travel Patterns • Vehicle Electric Range
H₂ Electrolysis 	Very High (Central) Limited (Distributed)	• Hydrogen Storage Capacity • Consumer Refueling Patterns (Distributed)
H₂ Distribution 	Limited to Moderate	• Pipeline ◦ Line Pressure Management • Gaseous Truck / Liquid Tanker ◦ Storage Capacity ◦ Delivery Schedules
H₂ Dispensing 	Limited	• Consumer Refueling Patterns • Refueling Station Balance-of-Plant Operation
<u>Potential Benefits and Synergies with Appropriately Dispatched Loads</u>		
• Allow renewable generation to be passed on to the transportation sector: ◦ Utilize excess renewable generation for transportation fuel (E) ◦ Reduce extra power plant capacity / fuel usage to meet additional load (E,C) • Aid in smoothing the effects of renewable variability: ◦ Minimize power plant start-up events (E,O) ◦ Minimize severity of part-load operation (E,O) ◦ Maintain high power plant fleet capacity factor (C) ◦ Limit increases in the cost of electricity (C) ◦ Reduce difficulty in maintaining grid reliability margins (O) ◦ Decrease uncertainty in net load forecasts (O) ◦ Manage variable power flow on transmission and distribution systems (O)		

Much of the knowledge base used to develop technology policies to reduce GHGs has been based on consideration of electricity and transportation sectors in isolation. The typical framework for determining pathways towards meeting GHG reduction targets has been focused on:

- Evaluating the effectiveness of decarbonizing technologies on the emissions of the sectors that they are deployed in, and
- Summing up the individual contributions of each sector to determine the overall GHG emissions reduction

This is a logical basis for determining GHG emissions, and has been visualized by the concept of stabilization wedges presented by Pacala and Socolow [322]. It has been used as the primary means for visualizing the effectiveness of deploying technologies in different resource sectors by many studies focusing on decarbonizing energy usage [323-327].

This approach is limited, however, by assuming that the deployment of decarbonizing technologies will only affect the emissions of the sector within which it operates. Deployed technologies can increase or decrease the emissions profile of other sectors. Coordinated deployment of decarbonizing technologies may aid different sectors in mitigating operational issues as well. These interactions are especially strong regarding the electricity and transportation sectors. In terms of wedges, deploying decarbonizing technologies in separate sectors will not only change the size of their corresponding stabilization wedges, but also their sum. These interactions can act to decrease or increase the combined effect on GHG emissions. One example of these interactions is presented in Figure 181.

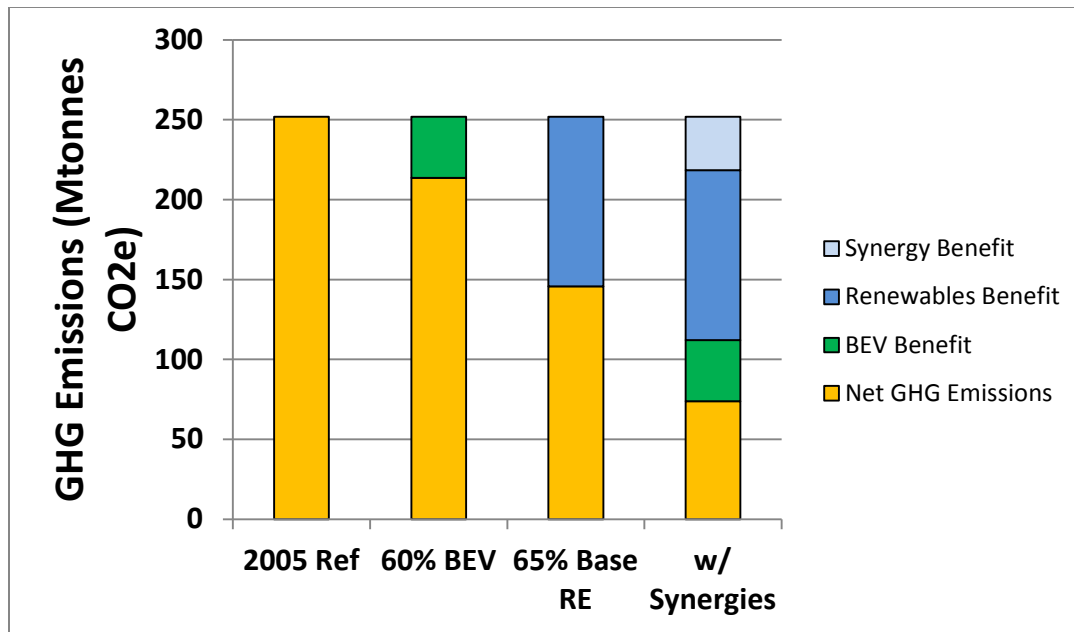


Figure 181 – Examples of synergistic interaction between decarbonizing technologies.

BEV deployment alone is limited due to increased fuel usage on the electric grid to meet charging loads. Renewable deployment alone is limited by grid reliability margins, base load generation, and dynamic limits on balancing power plants. When deployed in tandem, the reduction in GHG emissions is larger than the sum of the individual contributions due to synergies between technologies such as allowing excess renewable generation to be used to serve transportation loads.

In this context, the aim of this study is to:

- Map out the design space and identify where synergies between decarbonizing technologies are strongest
- To advise the direction of renewable energy and alternative vehicle policy and compare with current trajectories

- To compare the effectiveness and impact of two promising alternative vehicle options in the holistic, integrated context of an increasingly renewable electric grid

6.1.2.2. Approach

To compare and contrast the synergies and interferences of integrating alternative transportation options with a renewable-based electric grid in the context of the environmental performance of the holistic system, appropriate and comparable scenarios must be developed. This study aims at examining these sensitivities not only at discrete points, but rather the evolution of these sensitivities with respect to renewable deployment and vehicle fleet turnover. To accomplish this, a spanning approach is adopted. Utilizing a spanning approach allows a large amount of insight to be garnered regarding when key synergies and interferences between these technologies begin to emerge, the strength of these effects, and what system configurations are appropriate or not appropriate for reaching greenhouse gas reduction goals.

It is also important to note that in order to generalize the larger findings of the results; the spanning approach is carried out on the basis of renewable penetration and vehicle-miles-traveled penetration levels. These control parameters will be defined in the following sections. Using this basis allows the results to not be tied to a specific year and rather allows the space of system configurations to be explored. These implications can be important for policy planners in California and other systems with regards to the direction that legislation is advised to take from a technical standpoint.

This section describes the spanning cases for each of the control parameters used to develop the space of scenarios used in this analysis.

6.1.2.2.1. Deployment of Renewable Electric Grid Resources

The first major control parameter is called the **Base Renewable Penetration**. This refers to the percentage of the total electric load that is served by renewable energy without any interface with transportation. This is defined similarly to that used in Section 6.1.1. The effect of interfacing with the transportation sector can be determined for fixed renewable capacities to display benefits or disadvantages more clearly.

The mix of renewable resources as a function of base renewable penetration level is presented in Figure **182**:

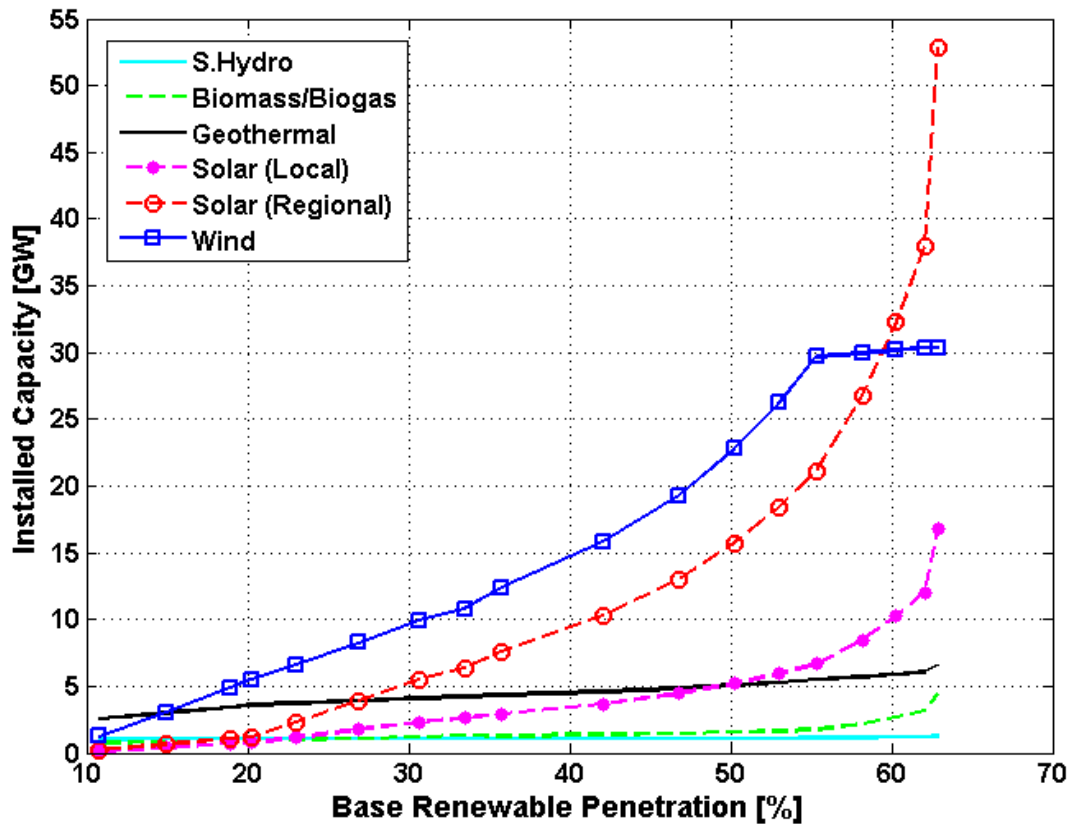


Figure 182 - Renewable Mix vs. Base Renewable Penetration Level

The renewable deployment curve was developed using the specifications for the percentage of energy delivered by each renewable resource in the same manner as that for the analyses in Section 6.1.1.

Nuclear power capacity was assumed to be constant across all scenarios, whereas coal power capacity was set to decrease with renewable penetration in reflection of current trends in California. The progression of the base load coal capacity is an extrapolation of the coal generation trends from 2005-2011 displayed by the California Energy Commission Total Electricity System Power [299]. The energy delivered is converted to capacity using representative coal plant capacity factors from eGRID [72]. Coal capacity is set to reach zero by the 33% base renewable penetration level.

6.1.2.2.2. Deployment of Plug-in Electric and Fuel Cell Vehicles

6.1.2.2.2.1. Vehicle Penetration Level

The second major control parameter for the spanning study is the **Vehicle Penetration Level**.

The vehicle penetration level refers to the percentage of the vehicle-miles-traveled (VMT) demand of the state that is served by non-gasoline vehicles. In order to develop a common basis by which to compare the deployment of plug-in electric vehicles and hydrogen fuel cell vehicles for the study conducted, the use of a vehicle miles traveled basis was selected. This is appropriate since it is the VMT demand that must be met to satisfy consumer transportation needs, regardless of which vehicles are used.

This study considers the year 2005 as the test year; however, the results are still generalizable as the effect of non-gasoline vehicles is performed on a percentage basis. For reference, the daily VMT demand that is met by these vehicles as a function of the PEV or FCV vehicle penetration level is presented in Table 59:

Table 59 - Daily VMT Served as a Function of PEV/FCV Penetration for 2005

<u>PEV or FCV Penetration [%]</u>	<u>Daily VMT Served</u>
1	7581184
2	15162368
3	22743552
4	30324736
5	37905920
10	75811840
15	113717760
20	151623680
25	189529600
30	227435520
35	265341440
40	303247360
45	341153280
50	379059200
55	416965120
60	454871040
100	758118400

For this particular study, the vehicle penetration level for both plug-in electric vehicles and hydrogen fuel cell vehicles was varied from 0% to 60%. A 0% vehicle penetration level represents the reference case of installing grid renewable resources without the deployment of non-gasoline vehicles. The vehicle penetration level is increased in 1% increments until the 5% vehicle penetration level, after which the increment size is increased to 5%. A higher resolution of increments was utilized since the turnover rate of vehicles in the light-duty fleet is on the order of 8-15 years. Due to this, it will take time for newly released plug-in electric and hydrogen fuel cell vehicles to be present on the road in significant enough numbers to serve a noticeable fraction of the VMT demand. Therefore, smaller vehicle penetration levels represent more realistic cases for deployment levels in the next few years within California. The upper limit of the vehicle penetration range considered in this study is 60%. This was considered to be

sufficient to demonstrate the trends and effects of implementing PEVs and FCVs on the electric grid and on the combined electric grid-transportation system.

6.1.2.2.2.2. Vehicle Performance and Infrastructure Parameters

This section will describe the selection of the vehicle performance and infrastructure configurations described in the PEV and FCV infrastructure model descriptions for this particular study.

Plug-in Electric Vehicles

As discussed in the description of the PEV charging model, the vehicle performance can be represented on this scale by the parameters of electric driving range and vehicle efficiency. The electric driving range and vehicle efficiency parameters for currently deployed plug-in electric vehicles as rated by the U.S. Environmental Protection Agency are presented in Table 60:

Table 60 - EPA Rated Vehicle Efficiency and Electric Driving Range of Currently Deployed PEVs

<u>Vehicle</u>	<u>EPA Classification</u>	<u>Vehicle Efficiency (kWh/mi) AC</u>	<u>Electric Range (mi)</u>
Fiat 500e	Subcompact Cars	0.29	87
Honda Fit EV	Small Wagon	0.29	82
Mitsubishi i-MiEV	Compact Cars	0.30	62
Ford Focus Electric	Compact Cars	0.32	76
Nissan Leaf	Midsize Cars	0.29	75
Tesla Model S (40 kWh)	Large Cars	0.36	139
Tesla Model S (60 kWh)	Large Cars	0.35	208
Tesla Model S (85 kWh)	Large Cars	0.38	265
Toyota RAV4 EV	Small SUV	0.44	103
Azure Dynamics Transit Connect EV	Special Purpose Vehicle	0.56	56

Depending on the size and weight of the vehicle, size of the battery pack, engineering of the drivetrain and associated control algorithms, and the aerodynamics of the vehicle, the vehicle efficiency and electric driving range can vary substantially.

Additionally, it is also important to recognize that the actual vehicle efficiency and electric driving range that will be exhibited by these vehicles in operation can become significantly different than the parameters displayed in the EPA-ratings. The actual vehicle efficiency and electric driving range depends strongly on consumer driving behavior, ambient conditions, terrain, and usage type. In many cases, it is recognized that the on-road vehicle efficiency and therefore electric driving range is often lower than that predicted by the EPA ratings at least for gasoline vehicles. This occurs because typical drivers are more aggressive, driving at higher speeds and greater rates of acceleration compared to those simulated in the EPA tests [328]. This trend is assumed to be present in this study.

With those considerations in mind, the selected parameter values for a representative plug-in electric vehicle serving the needs of the light-duty transportation fleet are as follows:

Table 61 - Selected BEV Performance Parameters

<u>Parameter</u>	<u>Value</u>
Electric Range	200 miles
On-Road Fleet Average Vehicle Efficiency	0.40 kWh/mi AC

This study assumes that BEVs are able to be used as the primary mode of transportation for consumers for a specified VMT share. Data from the National Household Transportation Survey shows that majority of consumers drive about 35 miles per day [62] on average. Using a vehicle as a primary mode of transportation, however, entails that the vehicle is able to meet essentially all consumers' needs. This includes drivers who regularly travel long distances, and typical

drivers who occasionally travel long distances (i.e. for weekends and recreational activities). Therefore, to allow BEVs to be used in this manner for the specified VMT share, a range of 200 miles is selected. With a 200 mile range, BEVs are able to serve 95% of the vehicle trips undertaken by consumers according to travel patterns specified in the NHTS data. This is also supported by the need to alleviate range anxiety to allow large uptake rates of BEVs in the marketplace.

The electric consumption of an electric vehicle tends to be very sensitive to driving range. Increasing the range of an electric vehicle involves increasing battery capacity, which due to the relatively low energy density of current and near-term battery technology, implies large increases in weight. Additionally, when representing the light duty vehicle fleet, it is also important to recognize that different sizes of cars will perform different roles for the consumer. Therefore, selecting only one vehicle type to represent the fleet would not be appropriate. According to the EMFAC model [151], trucks and sport-utility vehicles composed approximately 40% of the light-duty VMT demand for the test year of 2005. These vehicles are typically heavier and less efficient than passenger cars.

Therefore, an **on-road** fleet average vehicle efficiency of 0.40 kWh/mi was selected taking into account all of the aforementioned factors.

As discussed in the model description, the infrastructure configuration can be represented for the purposes of this study by the location of charging stations and the maximum charging power per unit. For this study, the following parameters are chosen:

Table 62 - Selected EV Infrastructure Configuration Parameters

<u>Parameter</u>	<u>Value</u>
Charging Station Locations	Home Only
Charging Power per Vehicle	6.6 kW (Level 2)

The deployment of EV charging infrastructure is difficult to predict. According to the NHTS data and work presented by Zhang [61], typical consumer travel patterns dictate that vehicles spend about 75% of their dwelling time at residences with the longest continuous periods. Given the relatively long charging times of EVs compared to the fill times of conventional gasoline vehicles, allowing home charging is a priority for a robust electric vehicle infrastructure. The installation of chargers beyond the home location will be determined by a number of factors including but not limited to: capital cost, utilization, distribution network expansion, and marginal utility. With chargers installed at the home location, the ratio of chargers to vehicles is roughly 1-to-1. If expanded to include work charging or everywhere charging, this ratio increases exponentially, increasing cost and supporting infrastructure requirements in the same manner. Therefore, for this study, the use of home charging only was selected.

The maximum charging power per vehicle is determined by a number of factors including but not limited to: the physical capacity of the charging unit itself, distribution circuit capacity, and management of power quality on distribution circuits. Since electric vehicle charging is purely a distribution-side load demand, the distribution circuit may be placed under heavy strain in neighborhoods with high electric vehicle concentrations. The maximum charging power, however, determines the time needed to charge the vehicle to its maximum range. As per consumer requirements, this time period cannot be too extensive or consumers may not be able to meet their transportation needs.

In the state of California, it is mandatory for all PEVs have an on-board charger with minimum output of 3.3 kW. This is to provide the current electric vehicle fleet, which have all-electric ranges around 100 miles, with the ability to obtain a near-full charge overnight. Most PEVs on the market have just met this requirement rather than having a larger charger on-board. Zhang [61] has shown that the average dwelling time at home is more than 10 hours, which is sufficient with this charging power. While NHTS data shows that the majority of consumers would not utilize a full battery charge on average from day-to-day, many consumers will occasionally drive long distances. In this study, BEVs are assumed to meet all of the consumer's transportation needs in order to be comparable to FCVs.

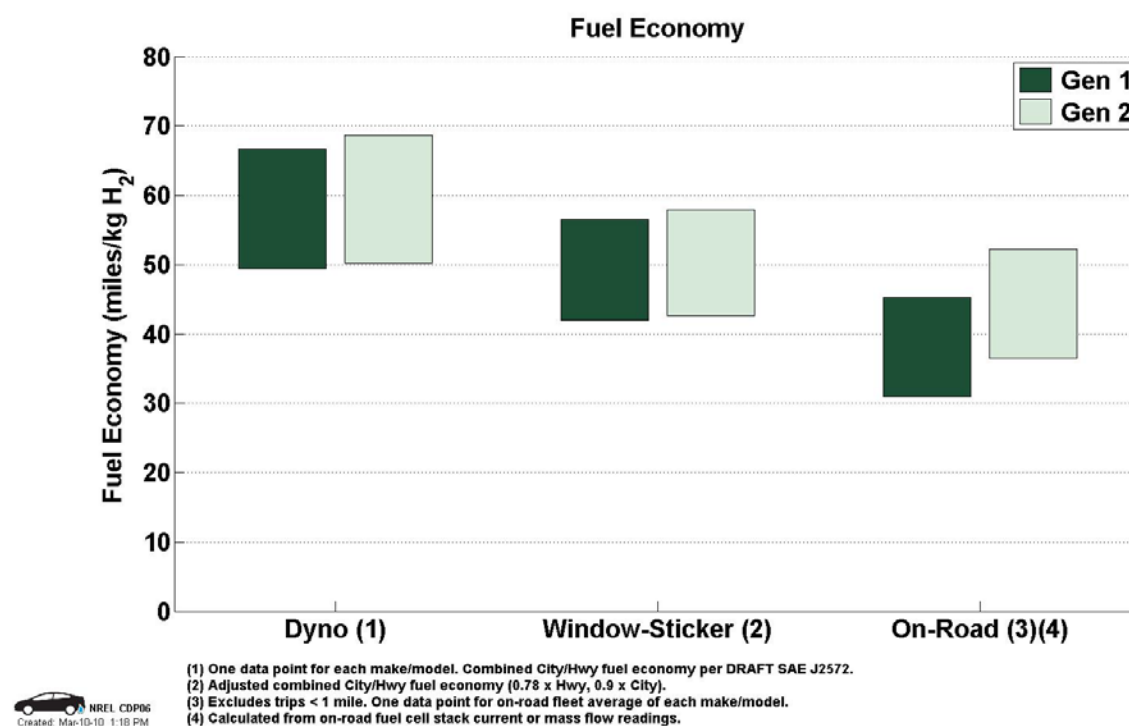
Therefore, when considering vehicles with a 200 mile range and the use of BEVs to meet all of a consumer's transportation needs, the necessary charging power is increased to about 6.6 kW.

This is to allow BEVs to have similar usage patterns as FCVs.

Hydrogen Fuel Cell Vehicles

As discussed in the description of the hydrogen fuel cell vehicle infrastructure model, the hydrogen demand is determined by the VMT demand and the vehicle efficiency of the hydrogen fuel cell vehicle fleet. The fuel cell vehicle fleet efficiency was obtained using the on-road fuel economy projections for Generation 2 fuel cell vehicles provided by NREL [329], as displayed in Figure 183:

Figure 183 - Generation 1 and Generation 2 Fuel Cell Vehicle Efficiency (NREL)



Slightly higher than the high end of the range was utilized to account for improvements in vehicle technology, resulting in an average on-road fleet efficiency of about 54 mi/kg. The on-road fuel economy is selected rather than the window-sticker fuel economy since it is the former that actually contributes to energy usage, cost, and greenhouse gas emissions. This takes into account the presence of a mixed vehicle fleet.

It is also important to note that for hydrogen fuel cell vehicles, it is not necessary to track the trip data of every individual car. Due to longer driving ranges and a parallel of the gasoline refueling paradigm, consumers have more flexibility regarding how to plan their trips. Additionally, since the temporal behavior of hydrogen demand is somewhat decoupled from hydrogen production on very short timescales, the effect on the aggregate system can be captured without tracking individual cars.

Contrary to the electric vehicle infrastructure, which is tied to that of the electric grid with the exception of the charging units, the hydrogen infrastructure is a separate platform altogether. Therefore, there are many more components of the hydrogen infrastructure that need to be configured to represent the energy and emissions impacts of meeting the hydrogen demand.

As described in the model description, the major components of the hydrogen infrastructure are:

- Production of Hydrogen
- Delivery of Hydrogen
- Dispensing of Hydrogen

Representation of each of these components will be described here.

Production

Hydrogen can be produced through a variety of methods which use different types of resources. Processes such as electrolysis, coal gasification, and steam methane reformation represent major options, and the relative mix of these methods can have a significant effect on the energy, emissions, and grid operations impact of using hydrogen fuel cell vehicles. Therefore, it is important to consider multiple production mixes to understand the possibilities of the relevant effects on the system.

For this particular study, two hydrogen production methods are considered: electrolysis using grid electricity and steam methane reformation (SMR). Coal gasification is not considered due to California's initiatives to decrease reliance on coal power.

Steam methane reformation of natural gas is a mature technology that is currently used in producing bulk hydrogen for gasoline refining, and accounted for about 48% of all hydrogen

production worldwide in 2005 [330]. This method is also currently the cheapest method of producing hydrogen and has very high energy conversion efficiencies [100]. Due to the use of natural gas, however, this process does emit some level of greenhouse gases and criteria pollutants. Regardless, SMR is likely to play an important role in hydrogen production due to the aforementioned factors.

Electrolysis using grid electricity is another promising method of producing hydrogen. This method represents the strongest potential interface between the hydrogen infrastructure and the electric grid, due to the use of large amounts of electricity and the potential for use as a dispatchable load. This method also represents a major potential link for the usage renewable resources to produce hydrogen. Currently, however, electrolysis is only mature on the small-scale and can be quite expensive relative to other methods. Regardless, electrolysis may fulfill a key role in the hydrogen infrastructure, especially as increased renewable integration and the need for grid management occurs in future years.

The fraction of the hydrogen demand for a given vehicle penetration level that is met by steam methane reformation is an input to the model. For this study, **the SMR fraction is varied between 0% and 100% in increments of 10%.** The remaining fraction of the hydrogen demand is the met by the appropriate amount of grid-based electrolysis. Finally, all hydrogen production is assumed to be centralized.

Distribution and Dispensing

Once hydrogen is produced, it must be distributed to hydrogen stations. This can be accomplished by a number of methods, including delivery of gaseous hydrogen in a tube trailer by truck, delivery of liquid hydrogen by tanker, or delivery of gaseous hydrogen through a

pipeline network. Additionally, once hydrogen is delivered to hydrogen stations, it must be pressurized for dispensing into the gaseous tanks of hydrogen fuel cell vehicles. This pressurization, along with other hydrogen station balance of plant loads, consumes electric energy that must be accounted for. Currently, hydrogen fuel cell vehicles contain storage tanks that operate at either 350 or 700 bar pressures.

For each hydrogen production mix, base renewable penetration level, and vehicle penetration level, the following hydrogen distribution and dispensing options are considered:

Table 63 – Selected Distribution and Dispensing Options for Current Study

<u>Scenario</u>	<u>% Gaseous / Tube Trailer Truck</u>	<u>% Liquid / Tanker</u>	<u>% Gaseous / Pipeline</u>	<u>Dispensing Pressure (bar)</u>
GHG-Optimized	0	0	100	350
Near-Term	50	50	0	700

The ‘GHG-optimized’ case involves the selection of distribution and dispensing infrastructure components that provides the lowest GHG-intensity. In this case, this involves the construction of an appropriate network of high pressure hydrogen pipelines and pumping stations, likely sited in the same corridors as natural gas pipelines. This scenario eliminates the need for delivery vehicles and ties all of the energy consumption of the distribution component to the electric grid. Additionally, this scenario assumes that storage capabilities have evolved to meet performance preferences at 350 bar pressures to alleviate safety constraints and represents a long-term or ‘future’ scenario.

The ‘near-term’ represents somewhat of a parallel of the current gasoline distribution method, which is delivery by truck. Liquid hydrogen is considered due to higher carrying capacities

compared to gaseous hydrogen in tube trailers and the potential need to transport hydrogen over long distances, but is limited due to extremely high energy consumption of liquefying hydrogen. The energy consumption and emissions of the delivery vehicles is taken into account. Delivery by truck is the current method used for currently in-use hydrogen stations. Additionally, with current on-board storage capacities and to driving range preferences, 700 bar pressures are often required to carry enough hydrogen to meet performance characteristics, which has raised safety concerns. This case therefore represents a more near-term scenario, and serves as a reference case to compare the GHG-optimized scenario against.

Constructing Optimal GHG Production Scenarios

Once all of the scenarios are completed and the space of results is composed, optimal greenhouse gas scenarios are constructed. This is accomplished by examining the total combined greenhouse gases for different hydrogen production mixes at each base renewable penetration and vehicle penetration level. The production mixes that yield the lowest combined greenhouse gas emissions are selected at each point to compose the optimal greenhouse gas scenario. This represents the lowest total greenhouse gas emissions that can be achieved at a given base renewable penetration level and vehicle penetration level combination. The GHG optimal SMR fraction for both the GHG-optimized and near-term distribution and dispensing scenarios are presented in Figure 184 and Figure 185, respectively:

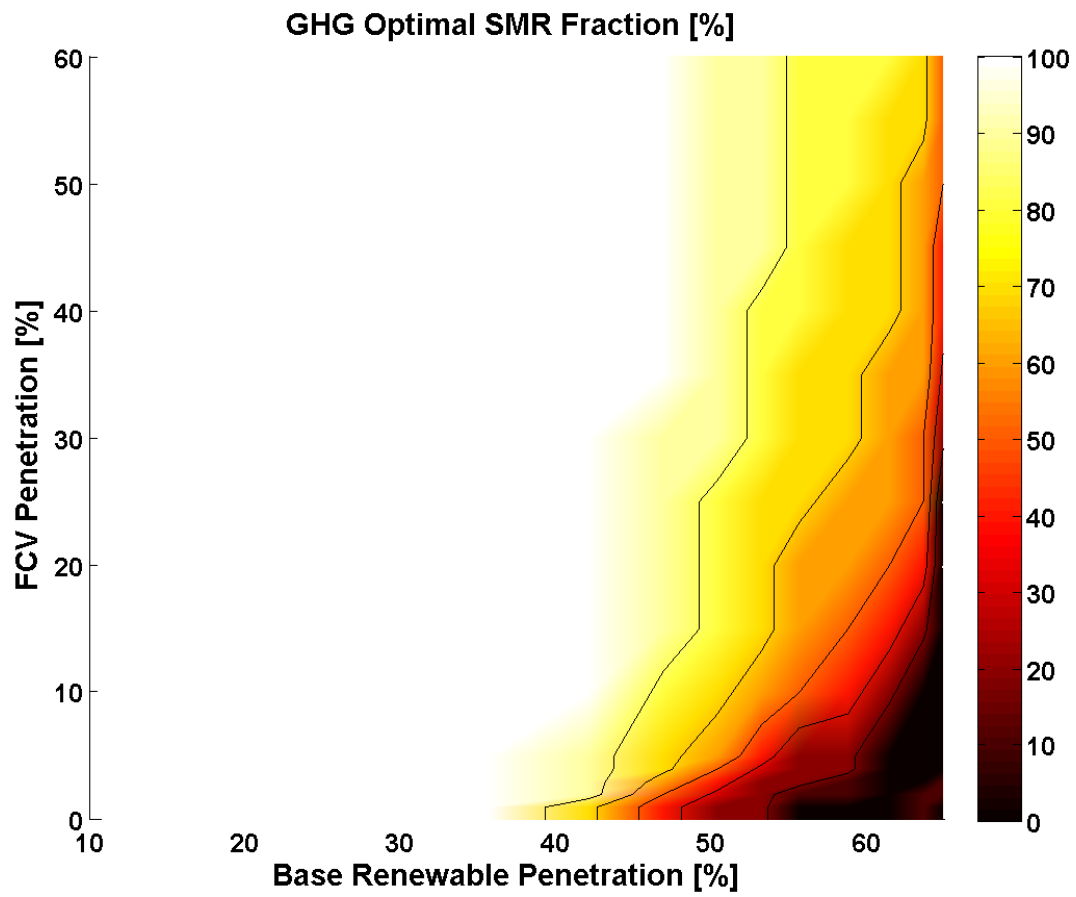


Figure 184 - GHG Optimal SMR Fraction: GHG Optimal Distribution and Dispensing

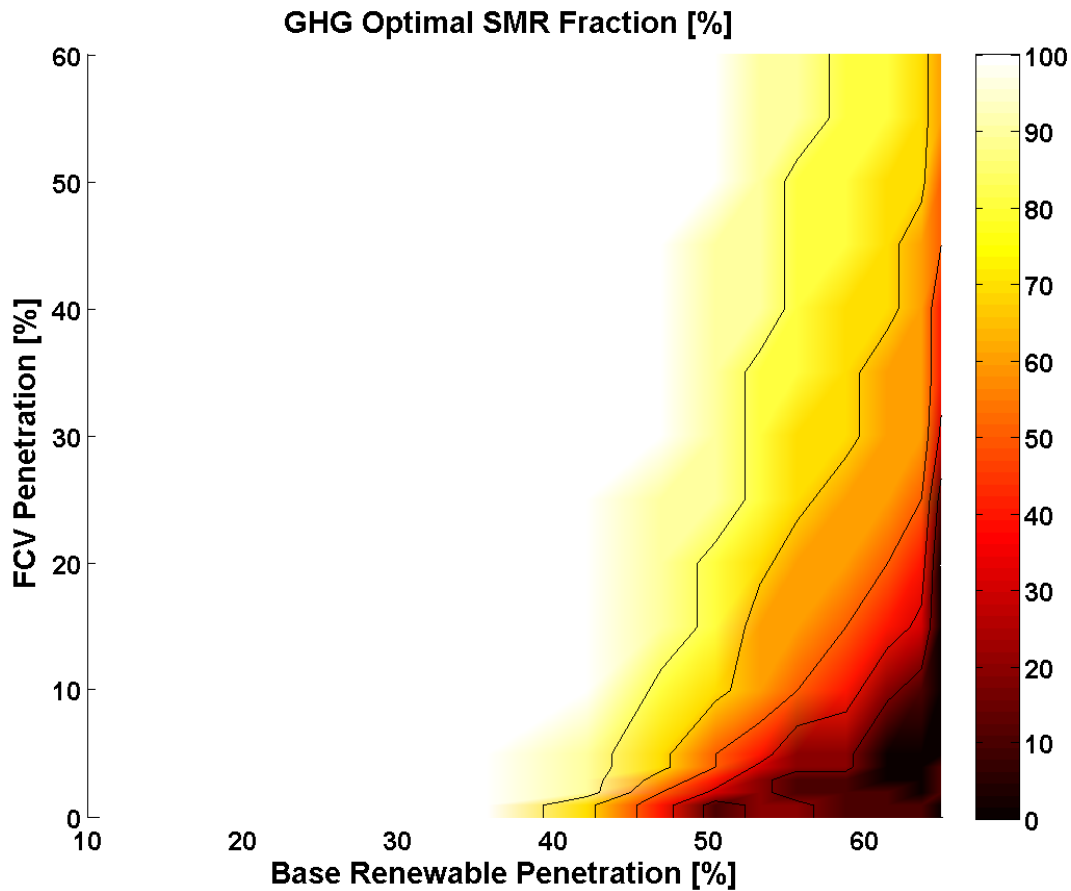


Figure 185 - GHG Optimal SMR Fraction: Near-Term Distribution and Dispensing

The construction of these optimal scenarios is aimed at shedding light onto the environmental and economic performance of the different manners in which the hydrogen infrastructure can be configured, and to identify what tradeoffs (if any) exist for prioritizing one major criterion over another.

6.1.2.2.3. Metrics for Analysis

In order to assess the performance of the combined electricity and transportation system as well as their individual performance and their sensitivity to the different technologies that have been deployed, quantitative metrics have been developed. These metrics are described here.

6.1.2.2.3.1. Major Metrics

These “major” metrics are those which characterize the performance of the combined electricity and transportation sectors as a whole.

- **Combined Greenhouse Gas Emissions:** This refers to the total greenhouse gas emissions sourced from every component of the electricity and transportation sectors combined. This metric is calculated by adding up the greenhouse-gas emissions from electric grid operation, gasoline vehicles, and any element of the alternative vehicle infrastructure that produces emissions independent of their effect on the electric grid. This inherently includes the inter-sector interactions that affect the behavior of each individual component. Both upstream and operating emissions of each sector are included, as well as secondary greenhouse gas emissions from every process considered. This metric is important for determining the potential of each technology in helping the entire system meet its greenhouse gas reduction goals.
- **Cost of Energy per Capita:** This refers to the cost of financing, operating, and maintaining the infrastructure required to provide energy to meet consumers’ stationary electric and transportation-related energy needs, normalized by the population of the system. It is calculated by summing up the absolute annual costs of all electricity and transportation infrastructure components and normalizing that amount by the system population. This metric is important for understanding the economic impact of reaching greenhouse gas and overall sustainability goals, and can help identify cost-constraining components within the context of the entire system.

6.1.2.2.3.2. Minor Metrics

These “minor” metrics are those which characterize the performance of a given component of the electricity or transportation sectors. These metrics still take into account the influence of the other corresponding sector.

- **Levelized Cost of Electricity**: This refers to the cost of electricity per unit energy that consumers would be tasked with paying in order to ensure that all parties involved on the electric grid are able to recover their investment costs. This metric can also be used to quantify the value to the grid of utilizing alternative vehicle options.
- **Grid Renewable Penetration Level**: This refers to the energy fraction of the **total** electric load demand that is served by renewable resources, accounting for losses and curtailment and addition of the vehicle-related electric load demand. This metric is important for determining the effect that using different transportation options will have on the state’s ability to meet Renewable Portfolio Standard (RPS) goals.
- **Balancing Generator Fleet Capacity Factor**: This refers to the ratio of the average power produced by electric load balancing resources to that of the maximum power capacity of these resources. This measures the utilization of installed electric load balancing resources on the electric grid. A high number indicates high utilization and return on investment and is desirable to power plant owners.
- **Average Balancing Generator Start-Up Events**: This refers to the average number of times that an individual generator must start up. Increased start up events indicate increased generator degradation and emissions, especially with regard to criteria pollutant emissions

- **Balancing Generator Fleet Efficiency:** This refers to the exhibited operating efficiency of balancing generators due to the effects of renewable integration and alternative vehicle integration.

With these metrics in place, the study is able to examine a wide range of characteristics of the electricity and transportation sector as a combined entity as well as the details of individual sector performance.

6.1.2.2.4. Current California Policy Trajectory Curve

In addition to exploring the performance of the combined system in terms of the space of base renewable and alternative vehicle penetration levels, the primary results have been overlaid with a curve that represents the current trajectory of California's grid renewable and alternative vehicle deployment strategy. The construction of this curve is described here.

California's renewable portfolio standards are currently under the guidance of Senate bill X1-2 [303]. This measure aims to meet 20% of retail electricity sales (load demand) with renewable energy by the end of 2013, 25% by the end of 2016, and 33% by the end of 2020. The 33% base renewable penetration level is the highest level currently mentioned in a formal policy measure, although discussions for higher targets are taking place. Using these three points as a reference, and adding the actual renewable penetration level in the reference case of 2005, the trajectory of renewable deployment by year was extrapolated until the 65% base renewable penetration level, which is the highest level considered in this study.

Currently, California also has mandated the deployment of 1.5 million zero-emissions vehicles by the year 2025 [304]. While this deployment is currently the only solid policy measure, projections for the deployment of zero-emissions vehicles as a percentage of the total light-duty vehicle fleet have been developed by the California Air Resources Board up to the year 2050

[331]. This projection includes a mix of alternative vehicle types. This study, however, focuses on the comparison of battery electric and fuel cell vehicles, and the ZEV mandates are technology agnostic. Therefore, in this study, the penetration of ZEVs in each year is assumed to be composed of either all BEVs or all FCVs to allow comparison.

Using these assumptions yielded the following data. The blue highlights represent formal policy targets for renewable deployment, whereas the green highlights represent formal policy targets for ZEV deployment.

Table 64 - California Renewable and Zero-Emissions Vehicle Policy Trajectory

<u>Year</u>	<u>Base Renewable Penetration [%]</u>	<u>Vehicle Penetration [%]</u>
2005	10.70	0.00
2013	20.00	0.00
2016	25.00	0.00
2020	33.00	0.24
2021	34.15	0.92
2022	35.64	1.82
2023	37.13	2.97
2024	38.62	4.36
2025	40.11	6.00
2026	41.60	7.90
2027	43.09	10.06
2028	44.58	12.47
2029	46.07	15.13
2030	47.56	18.04
2031	49.05	21.17
2032	50.54	24.51
2033	52.03	28.05
2034	53.52	31.76
2035	55.01	35.62
2036	56.50	39.61
2037	57.99	43.69
2038	59.48	47.83
2039	60.97	52.00
2040	62.46	56.15
2041	63.94	60.00
2042	65.00	64.23

Overlaying the primary results with these curves allows the study to provide a sense of what benefits and disadvantages might be expected when deploying either of the alternative vehicle options considered.

6.1.2.3. Results – Major Metrics for an Optimal Hydrogen Infrastructure Configuration

The following results compare the effect of deploying BEVs and FCVs in conjunction with renewable resources on the greenhouse gas reduction and cost of energy per capita for the

combined electricity and transportation system. These scenarios use an optimized hydrogen production mix.

6.1.2.3.1. GHG Reduction Potential

When inter-sector interactions are considered, both BEVs and FCVs can achieve similar GHG emissions reductions if the hydrogen infrastructure is carefully designed to minimize emissions or BEV charging dispatch is optimized. The combined GHG emissions change as a percentage of the reference case value is presented for BEVs in Figure 186a and for FCVs as a difference from the BEV reduction in Figure 186b. A positive difference indicates an increased reduction compared to BEVs, and vice versa for a negative difference. The reference case refers to a 10.7% BRP and a zero alternative vehicle penetration level, representative of actual conditions present in the year 2005.

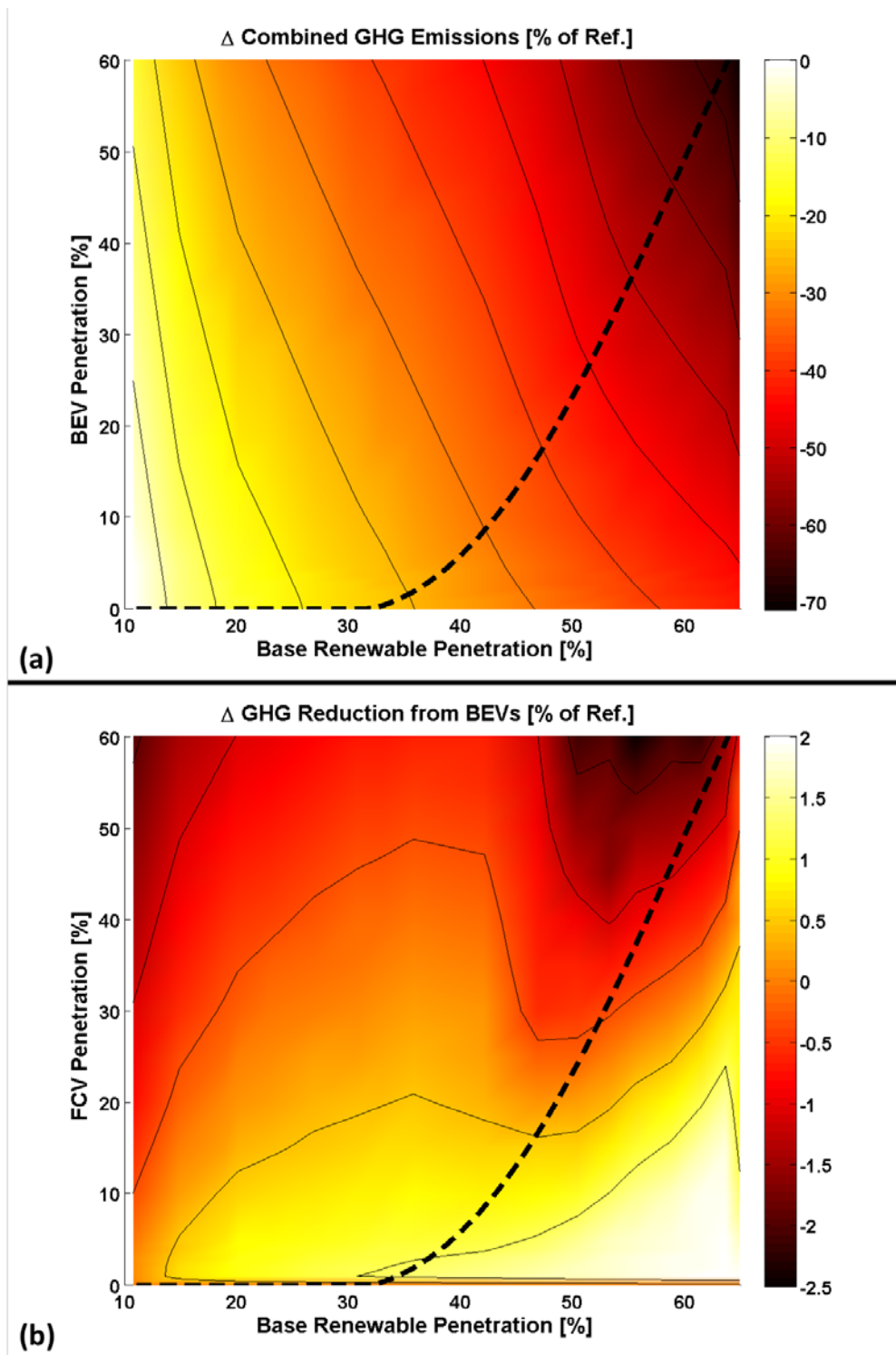


Figure 186 - (a) Reduction in combined electricity and transportation sector greenhouse gas emissions due to renewable and BEV deployment as a percentage of the reference case value, (b) Difference in combined sector GHG reductions from BEV value due to FCV deployment as a percentage of the reference case value. The dotted line represents the current CA policy trajectory according to RPS standards [303] and ZEV deployment projections [331].

The deployment of BEVs reduces the GHG emissions of the combined sectors by up to 70.6% when synergies with renewable resources are realized. In all cases, deploying BEVs reduces GHG emissions by reducing gasoline consumption. At low BRP levels, the grid-responsive dispatch of the charging load additionally reduces GHG emissions by allowing power plants to a) operate closer to their rated capacity, increasing efficiency and b) reduce the need for inefficient peaking power plants and related start-up emissions. These effects are partially offset by increasing the electric load, which increases power plant fuel use at high vehicle penetration levels. As the BRP level increases, this grid-responsive dispatch is able to utilize some portion of excess renewable generation that could otherwise not be utilized to serve the stationary load demand due to base-load generation, dynamic constraints on power plants, or a lack of load during a period of high renewable generation.

FCVs also reduce emissions from gasoline. At low BRP levels, these reductions are partially offset by emissions from steam methane reformation (SMR) and the scaling up of distribution and dispensing energy consumption at high vehicle penetration levels. As the BRP increases slightly, the presence of renewable resources to partially serve the distribution and dispensing loads in conjunction with high-efficiency SMR processes allows FCVs to have equal effects to BEVs on combined sector GHG emissions. At relatively low vehicle penetrations and high BRP levels, FCVs exhibit increased GHG emissions reduction potential compared to BEVs. In this region, a high amount of excess renewable generation is present. The GHG-optimized hydrogen production mix begins to rely on electrolysis to utilize this excess generation. BEVs are not as able to utilize this excess energy relative to central electrolysis due to 1) consumer driving patterns limiting the flexibility of the charging load relative to centrally-controlled hydrogen electrolysis and 2) not providing enough load to use all of the excess generation. These effects

allow FCVs to have increased GHG reductions compared to BEVs in this region. At high vehicle and BRP levels, FCVs exhibit slightly less GHG reduction potential compared to BEVs, due to the lower relative contribution of renewable resources towards a larger vehicle-based electric load.

The difference between a carefully-planned FCV deployment and a BEV deployment with optimized charging is between -2.5% to +2% of the reference case value of 251 metric tons CO₂e. While BEVs are 50-100% more efficient than FCVs on a tank-to-wheels basis [37, 287, 332], however, vehicle efficiency is not as important as the pathway efficiency from primary energy and the mix of primary energy being utilized. The effect of cross-sector interactions renders these two technologies as **essentially equal in GHG emissions reduction effectiveness**.

Additionally, with the application of the state's entire biogas potential to displace natural gas consumption, the maximum CO₂ reductions are increased by 2.84% in all cases for both FCVs and BEVs. The reductions are the same for both vehicle types since the **total** natural gas consumption in all cases is high enough to allow the entire biogas potential to be applied, whether for grid fuel or SMR feedstock.

These results are for optimal cases, however. The BEV charging dispatch assumed that consumers tailored their behavior to allow dispatch benefits. Without this communication, these benefits may not be practically realized to the same extent. Similarly, the FCV infrastructure was configured for minimal GHG emissions. If infrastructure deployment is not optimized in this fashion, the FCV GHG reduction potential is reduced compared to BEVs, as discussed in a later section.

6.1.2.3.2. Cost of Energy per Capita

The cost contributions of BEVs and FCVs are very different in nature. The **cost of energy per capita (CEPC)** refers to the amount per year paid to support the sustained provision of energy to meet system electricity and transportation needs normalized by population. This includes the costs for electricity to meet transportation and stationary needs, gasoline, and hydrogen for FCVs. This measure includes contributions from every infrastructure component necessary to support a given combination of technologies. BEV deployment imposes costs associated with increased electric loads on the grid, which can affect the cost of electricity depending on charging dispatch and renewable penetration, and the deployment of EV service equipment (EVSE) at all relevant charging locations. For FCV deployment, the majority of the associated cost is due to the required installation of production and supply chain equipment. Costs or savings due to effects on electric grid operation may also be present. The change in the CEPC from the reference case as a percentage of the reference case value is presented for BEVs in Figure 187a and for FCVs as a difference from BEVs in Figure 187b. A positive difference indicates increased costs compared to BEV deployment.

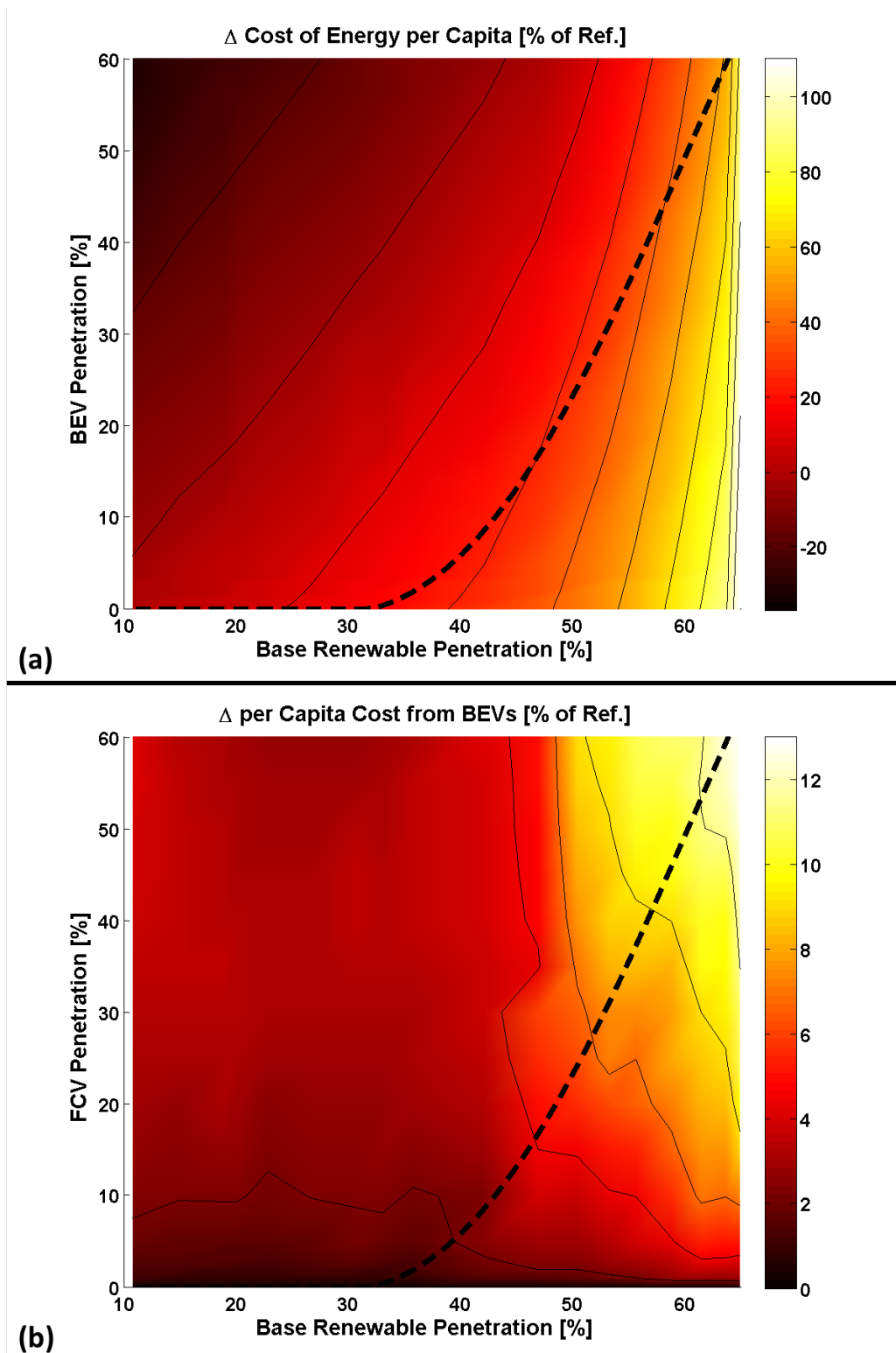


Figure 187 - (a) Change in the Cost of Energy per Capita (CEPC) due to renewable and BEV deployment as a percentage of the reference case value, (b) Difference in CEPC from BEV value due to FCV deployment as a percentage of the

reference case value. The dotted line represents the current CA policy trajectory according to RPS standards [303] and ZEV deployment projections [331].

The CEPC increases with BRP level in all cases. This increase occurs due to 1) the increased capital cost and lower capacity factors of many renewable generator types compared to conventional generation, 2) increased variability causing the capacity factor of the conventional generation fleet to decrease, 3) increased wear and tear on balancing generators due to dynamic operation, and 4) decreased efficiency due to extensive part-load operation of balancing generators. Additionally, at high renewable penetration levels, the onset of excess generation requires exponentially more renewable capacity to serve the same incremental fraction of the electric load demand, further increasing costs[221, 333].

The deployment of BEVs in conjunction with renewable resources decreases the CEPC relative to the no-BEV case. The deployment of long-range BEVs with grid-responsive load dispatch has a stronger effect at low renewable penetration levels. Even at large scale, the costs associated with the installation of EVSE infrastructure are relatively small compared to annual expenditures on electricity and gasoline. At the same time, BEV deployment reduces annual gasoline expenditures, and optimized charging increases the capacity factor of the balancing generator fleet by creating a steadier net load profile. These effects allow BEV deployment to reduce the CEPC by as much as 36.5% from the reference case at low renewable penetration levels. The relative economic benefit of deploying BEVs compared to the no-BEV case starts to diminish as the BRP increases. At higher renewable penetration levels, the cost of electricity increases significantly, increasing the cost of meeting the stationary load as well as BEV charging loads. The cost benefits of aiding grid operation are also diminished due to 1) the magnitude of renewable generation becoming too large for the BEV load to smooth during many hours of the year and 2) consumer travel patterns limiting the ability of the BEV charging load to adapt to

renewable generation characteristics. At a 65% BRP level, the CEPC is increased by 92.4% compared to the no-BEV case. The deployment of a 60% BEV penetration is only able to reduce this to 83.2%.

The CEPC is increased for FCV deployment compared to that for BEV deployment. This is not surprising given the substantial infrastructure investment required to support hydrogen FCVs. This difference, however, is not as large as implied from examining these costs without considering cross-sector interactions.

At low BRP levels, the increase in the CEPC due to a GHG-optimized FCV infrastructure is between 1% and 4.2% of the reference case value. In these cases, the GHG-minimal hydrogen production mix is dependent on SMR. Large-scale SMR is a mature technology used in industrial processes, and associated costs are mostly composed of natural gas feedstock costs. SMR also has a high efficiency, and only consumes a small amount of electricity. The added costs relative to BEVs in this region are due to installation and financing of the delivery (pipeline), dispensing, and storage equipment.

As the BRP level increases, however, the CEPC difference between FCVs and BEVs increases. The CEPC maxes out at about 13.7% of the reference case value higher than that for BEVs, occurring at a 60% FCV penetration level and a 65% BRP level. At BRP levels above about 40%, the hydrogen production mix begins to rely on electrolysis to varying extents to utilize excess renewable generation and minimize GHG emissions. Electrolysis, in contrast to SMR, has high capital costs. Additionally, using the electrolysis load as a dispatchable load, the electrolyzer fleet exhibits a relatively low capacity factor in order to follow the variability of renewable generation. Other infrastructure elements also utilize noticeable amounts of electricity,

which has become more expensive due to renewable generation. These factors combined cause the CEPC due to FCV deployment to increase relative to BEVs.

A primary limiting factor for FCV costs is the benefit that the dispatchable electrolysis load provides to electric grid operation. At high BRP levels, renewable generation variability is severe and excess generation is significant in these cases, and these effects increase the cost of electricity. The use of appropriate amounts of dispatchable central electrolysis, is able to counteract these effects more effectively than the BEV charging load due to two reasons. First, since the hydrogen production profile can be detached from consumer driving patterns due to storage and refueling paradigms, the electrolysis load is more flexible relative to BEVs even with optimized charging. Second, the hydrogen electrolysis load is larger than the BEV charging load. This allows it to make use of excess renewable generation to an extent that prevents balancing generators from turning down or shutting off, increasing the capacity factor of the balancing generator fleet. The net effect is that FCV deployment lowers the cost of electricity compared to BEVs when electrolysis is heavily used, as displayed in the results for the minor metrics. This acts to partially offset the significant cost of hydrogen infrastructure and limits the holistic cost impact relative to BEVs.

When cross-sector interactions are considered, the economic impact on the combined electricity and transportation sectors of deploying FCVs is slightly higher than that for long-range BEVs. Across the spectrum considered and with careful planning, the difference ranges from 1%-13.7%. The cost of hydrogen infrastructure is higher than that for BEV infrastructure, but the increased flexibility of the hydrogen electrolysis load provides a significant economic and practical benefit to the grid at high BRP levels. This conclusion only becomes apparent when

accounting for cross-sector interactions, and holds with a GHG optimized hydrogen infrastructure. To reach economic parity to the consumer with BEVs, the difference will need to be covered by other factors such as vehicle cost.

Again, these results are for optimal cases. If BEV charging was not intelligently dispatched, grid operation benefits relevant to reducing electricity costs may not be realized. Similarly, if the hydrogen infrastructure is not optimized, the combined cost differences between BEVs and FCVs are increased, discussed in the next section.

6.1.2.4. Results – Major Metrics for a Non-Optimal Hydrogen Infrastructure Configuration

The main conclusion of the previous section that BEVs and FCVs have similar GHG-reduction potential in the holistic scope and small economic impact differences only holds under the condition that the hydrogen infrastructure is carefully planned to minimize GHG emissions in the long term. If the hydrogen infrastructure is not carefully planned, FCV deployment becomes much less competitive than BEV deployment in many aspects. This section presents the combined sector GHG emissions reduction and the cost of energy per capita change for a hydrogen infrastructure relative to BEVs using the ‘near-term’ distribution and dispensing configuration instead of the GHG-optimal configuration.

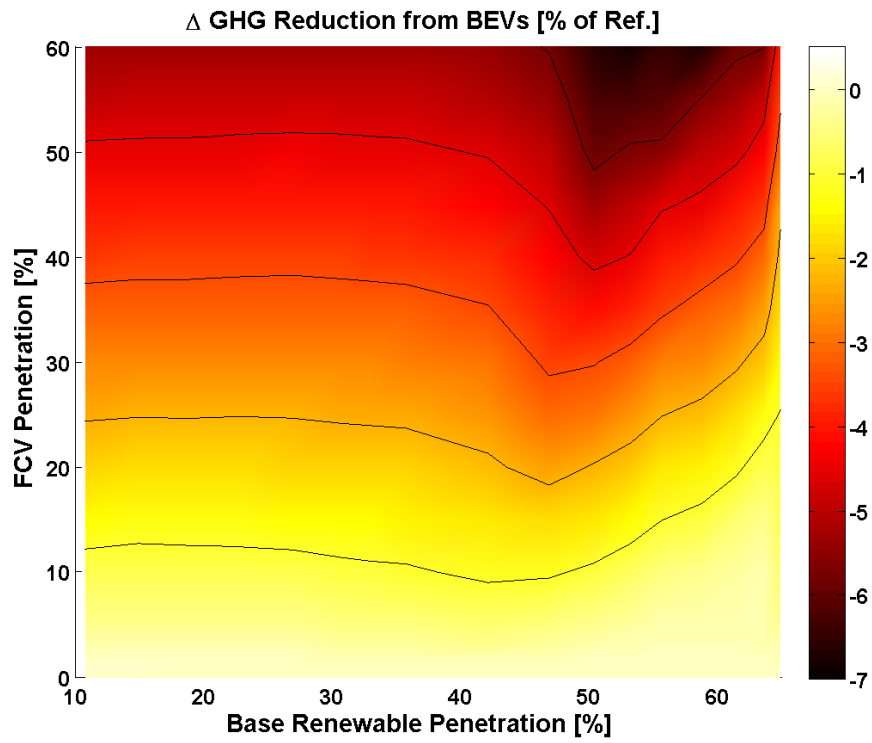


Figure 188 - Difference in combined sector GHG reductions from BEV value due to FCV deployment as a percentage of the reference case value for a Non-Optimal FCV infrastructure configuration

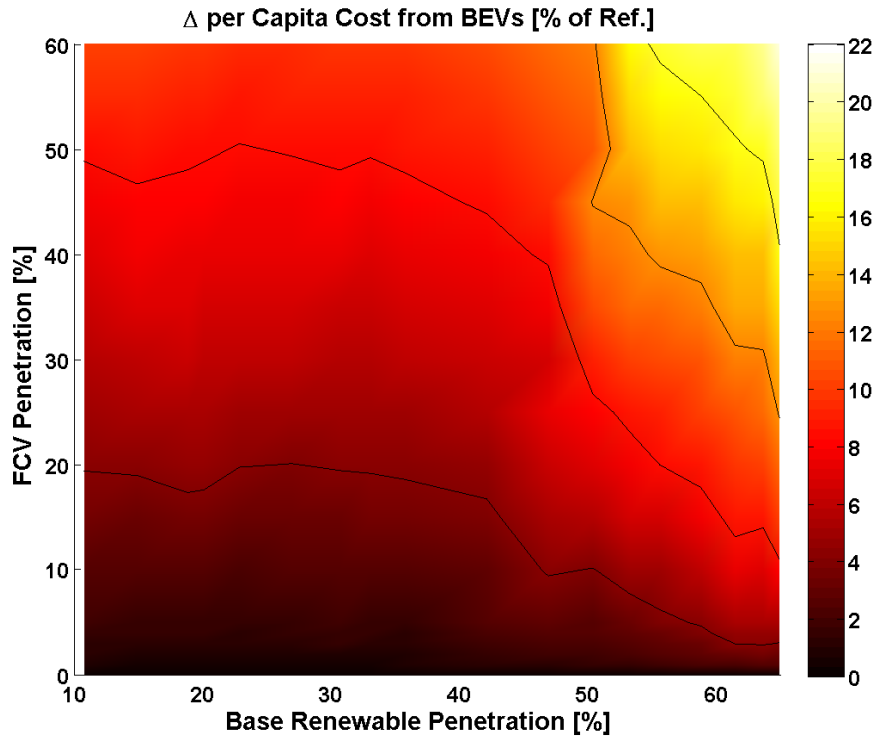


Figure 189 - Difference in cost of energy per capita from BEV value due to FCV deployment as a percentage of the reference case value for a Non-Optimal FCV infrastructure configuration.

With a GHG-optimal configuration, the change in the reduction of combined GHG emissions from that due to BEVs was about -2.5% to +2%. With the near-term infrastructure configuration, the range is expanded to between -6.9% to +0.03%. This indicates that with the near-term infrastructure configuration, FCV deployment will essentially not improve holistic GHG emissions reductions compared to BEVs, and therefore has less GHG reduction potential. This occurs due to the fact that the near-term hydrogen infrastructure configuration relies strongly on energy intensive liquefaction processes and high-pressure dispensing, which is not only energy intensive but can also add to peak load magnitudes.

The same trends are present for the effects on the cost of energy per capita. With a GHG-optimized distribution and dispensing infrastructure, the change relative to that due to BEVs was

between 1% and 13.7%. With a non-optimal dispensing and delivery infrastructure, the upper end of this range is expended to about 21.1%. The high energy intensity of liquefaction and high pressure dispensing becomes a heightened cost penalty at high base renewable penetration levels, since the cost of electricity has increased significantly.

This demonstrates the importance of appropriate infrastructure configuration for FCV deployment to be competitive with BEV deployment. If the hydrogen supply infrastructure is not deployed with consideration of minimizing GHG emissions in the long term, FCVs will be decidedly less competitive than BEVs.

6.1.2.5. Results – Minor Metrics

For the minor metrics, the scenarios use deployment of long-range BEVs with smart charging and the deployment of FCVs at two different production mixes: 100% Electrolysis and 70% SMR / 30% Electrolysis. This approach is taken to showcase the potential interactions between alternative vehicle deployment and electric grid operation, which is more clearly explained using constant production mixes for hydrogen production. Electrolysis loads are intelligently dispatched by the grid operators to smooth the net load demand. Note that the FCV cases do not correspond to the GHG-optimal production mix presented for the results in the previous section, where the production mix changes at every base renewable and vehicle penetration level.

6.1.2.5.1. Grid Renewable Penetration Level

Due to the additional loads placed on the electric grid by the charging of BEVs and the fueling of FCVs, the energy of the total electric load demand will increase with vehicle deployment.

Therefore, the actual renewable penetration level of this combined electric load will be different than the base renewable penetration level. These effects are presented for BEVs, FCVs with 0% SMR and FCVs with 70% SMR in Figure 190, Figure 191, and Figure 192 respectively. The metric

presented is the difference from the base renewable penetration level, which displays how the actual renewable penetration level has changed due to the addition of the transportation load.

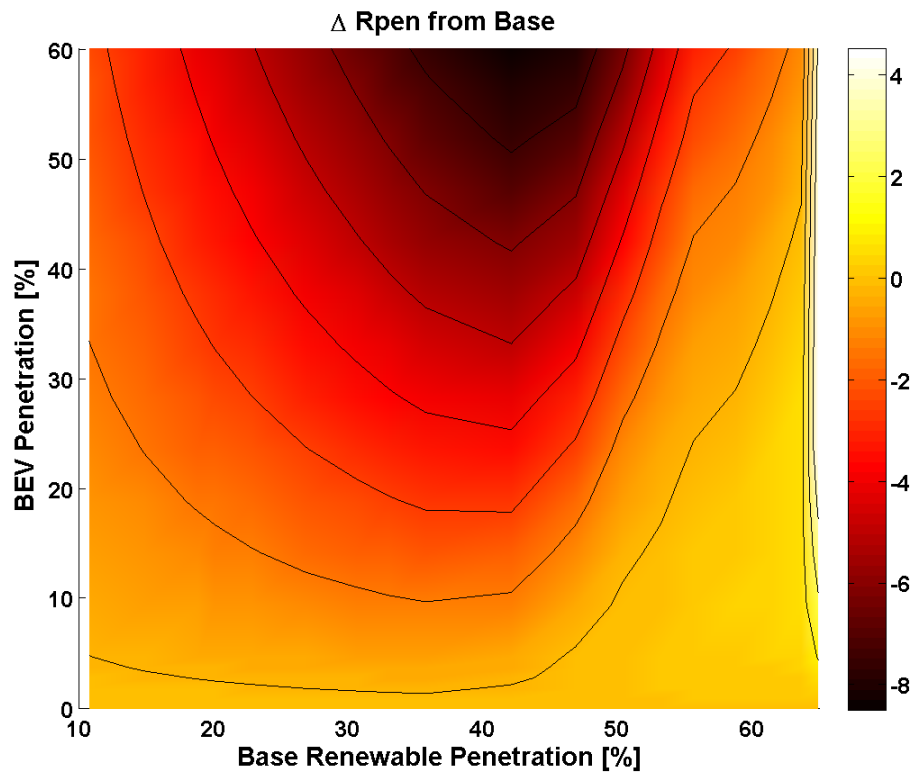


Figure 190 - Difference in Actual Renewable Penetration from Non-Transportation Cases: Long-Range BEVs with Smart Charging

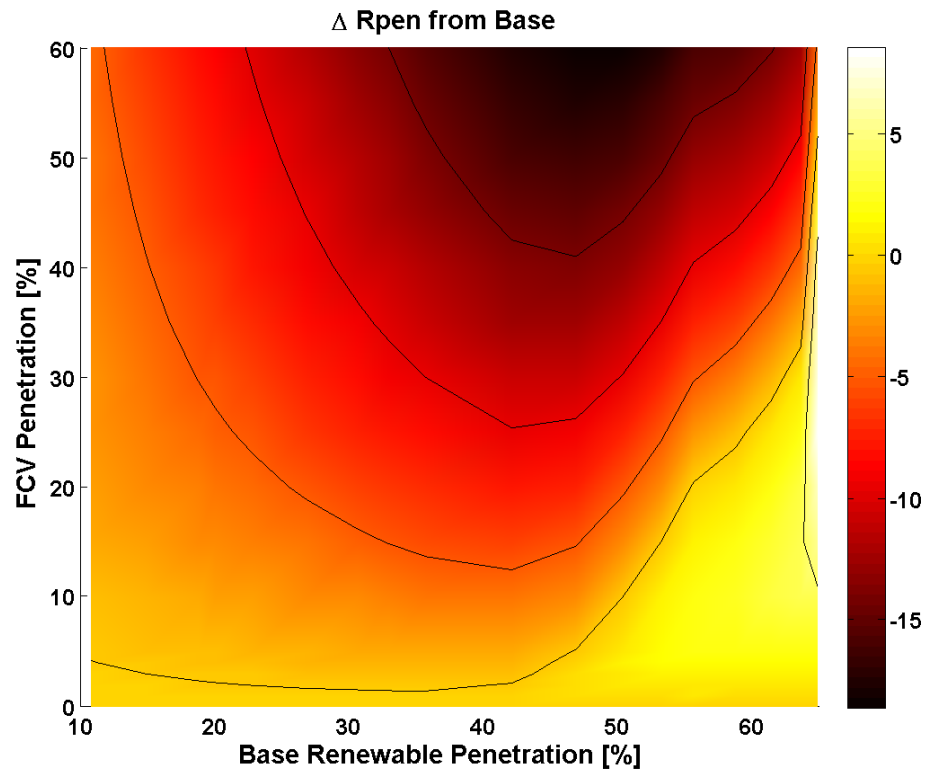


Figure 191 - Difference in Actual Renewable Penetration from Non-Transportation Cases: FCVs with 30% SMR and 100% Electrolysis.

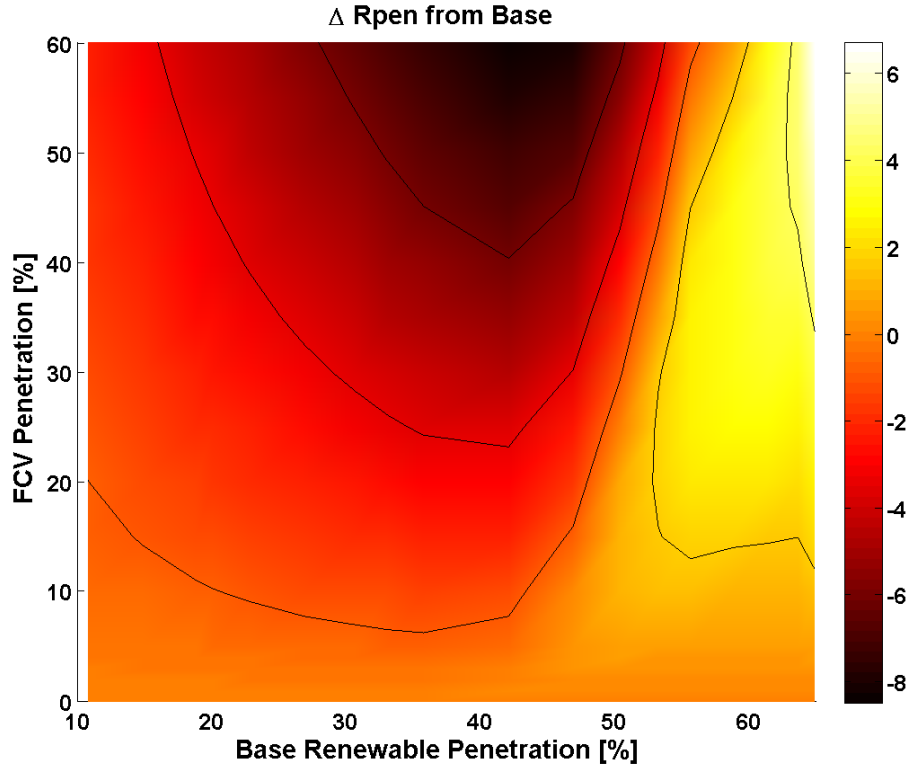


Figure 192 - Difference in Actual Renewable Penetration from Non-Transportation Cases: FCVs with 70% SMR and 30% Electrolysis.

The definition of the actual renewable penetration is:

$$R_{pen}[\%] = \frac{E_{Ren,delivered}}{E_{load}} \times 100$$

With regards to the integration of alternative vehicles, there are two competing forces that affect the change in renewable penetration from the base level.

First, the introduction of charging, electrolysis, or miscellaneous infrastructure loads onto the grid increases the overall electric demand. For example, the at a 60% BEV penetration level with a 200 miles range, the energy of the electric load demand increases by about 21%. This acts to decrease the renewable penetration level from the base value by increasing the denominator,

since a given amount of delivered renewable energy will count for a smaller fraction of the total load.

Second, the integration of alternative vehicles with grid-responsive dispatch capability acts to smooth out the load profile to the extent possible. In this case, BEVs and electrolyzers add load during periods when the net load demand is low, and refrain from adding load when the net load demand is high. During certain periods of extremely high renewable power generation, this dispatch can allow the grid to utilize any excess generation that could not be otherwise used due to grid reliability margins, un-interruptible base load generation, and limits on balancing generator dynamic capabilities. This serves to increase the renewable penetration level from the base value since renewable energy that would have otherwise been curtailed can be used to serve the load demand. It is very important to note, however, that for this effect to increase the renewable penetration level above the base value, the percentage of the additional load demand that is met by excess renewable generation must be higher than the base renewable penetration level.

With those forces in mind, the patterns in Figure 190, Figure 191, and Figure 192 can be understood. At low base renewable penetration levels, installed renewable capacities are too low to cause any significant amount of curtailment, and the first effect is dominant. Therefore, the addition of vehicle-based loads only serves to increase the electric load demand and decrease the renewable penetration level. As installed renewable capacities increase, the second effect starts to become dominant. In these regions, the renewable capacity is large enough such that curtailment of renewable generation becomes significant. The dispatch of BEV charging or electrolyzer loads allows this excess generation to be utilized, and the actual renewable

penetration level begins to increase. At higher base renewable penetration levels where the additional loads are able to utilize more excess renewable generation, the coupling of alternative vehicles allows the grid renewable penetration level to be increased above the base level.

The differences between long range BEVs and FCVs in this case is due to the differences in 1) the magnitude of the load demand added and 2) the flexibility of the dispatched load. Long-range BEVs alter the renewable penetration level in a range of about -8.1% to + 4.0%. This is in comparison to about -18.62% to + 8.51% for FCVs with 100% electrolysis, and -8.47% to + 6.68% for FCVs with 30% electrolysis. The magnitude of the BEV charging load is small compared to FCV electrolysis. However, limited dispatchability due to consumer travel patterns render the BEV charging load unable to utilize some of the excess renewable generation at high base renewable penetration levels. For FCVs with 100% electrolysis, the magnitude of the added load is very large. This causes the renewable penetration level to drop significantly when the first effect is dominant, but allows it to increase to a larger extent in regions where the second effect is dominant. FCVs with 30% electrolysis have a smaller load magnitude, but increased flexibility of dispatch allows it to have a range between the other two cases.

The larger decrease at the mid-range of base renewable penetration levels considered and high BEV or FCV penetration levels occur simply due to the fact that the renewable penetration level is more sensitive to additions of a constant load level at higher base levels from a difference standpoint. For example, consider the 60% BEV penetration level which increases the energy of the load demand by 21% at the 10.7% base renewable penetration level and a load of 100 energy units:

$$Rpen_{orig} = \frac{E_{Ren,delivered}}{E_{load,orig}} = 10.7\% = \frac{10.7}{100}$$

$$Rpen_{BEV} = \frac{E_{Ren,delivered}}{E_{load,orig} + E_{load,BEV}} = \frac{10.7}{100 + 21} = 8.84\%$$

$$\Delta Rpen = Rpen_{orig} - Rpen_{BEV} = 10.7\% - 8.84\% = 1.86\%$$

Consider the same amount of load added at a base renewable penetration of 30%:

$$Rpen_{orig} = \frac{E_{Ren,delivered}}{E_{load,orig}} = 30.0\% = \frac{30}{100}$$

$$Rpen_{BEV} = \frac{E_{Ren,delivered}}{E_{load,orig} + E_{load,BEV}} = \frac{30}{100 + 21} = 24.79\%$$

$$\Delta Rpen = Rpen_{orig} - Rpen_{BEV} = 30.0\% - 24.79\% = 5.21\%$$

Therefore, the difference in renewable penetration from base is expected to be larger at higher base renewable penetrations when the first effect dominates.

These results have strong implications for the state's ability to meet renewable portfolio standard goals in the long term, as large amounts of alternative vehicles are deployed. More importantly, a higher renewable penetration level on the grid does not necessarily correspond with maximum reductions in greenhouse gas emissions when the holistic system is considered. This further emphasizes the need for coordinated policy for decarbonizing technology deployment and modeling that accounts for cross-sector interactions and combined sector emissions performance.

6.1.2.5.2. Effects on the Balance Generator Fleet Capacity Factor

The introduction of dispatchable vehicle-related loads can serve to reduce the impact of variable renewable generation on the balancing generator fleet. These effects are presented regarding the balance fleet capacity factor with BEVs, FCVs with 0% SMR and FCVs with 70% SMR in Figure 193, Figure 194, and Figure 195, respectively.

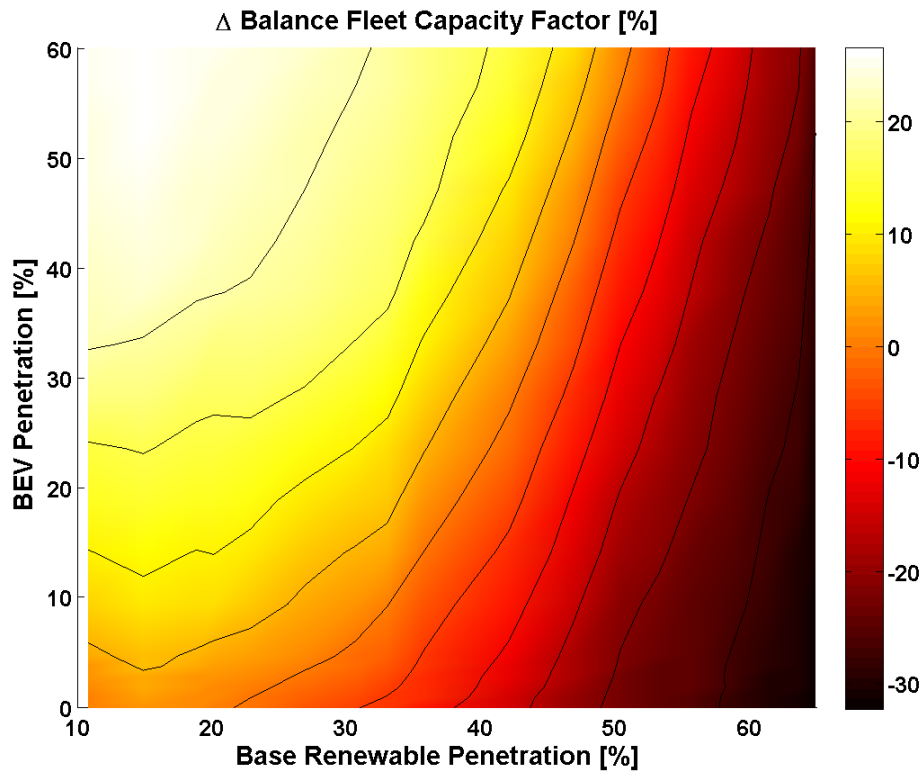


Figure 193 - Difference in Balancing Generator Fleet Capacity Factor from Reference Case: Long-Range BEVs with Smart Charging

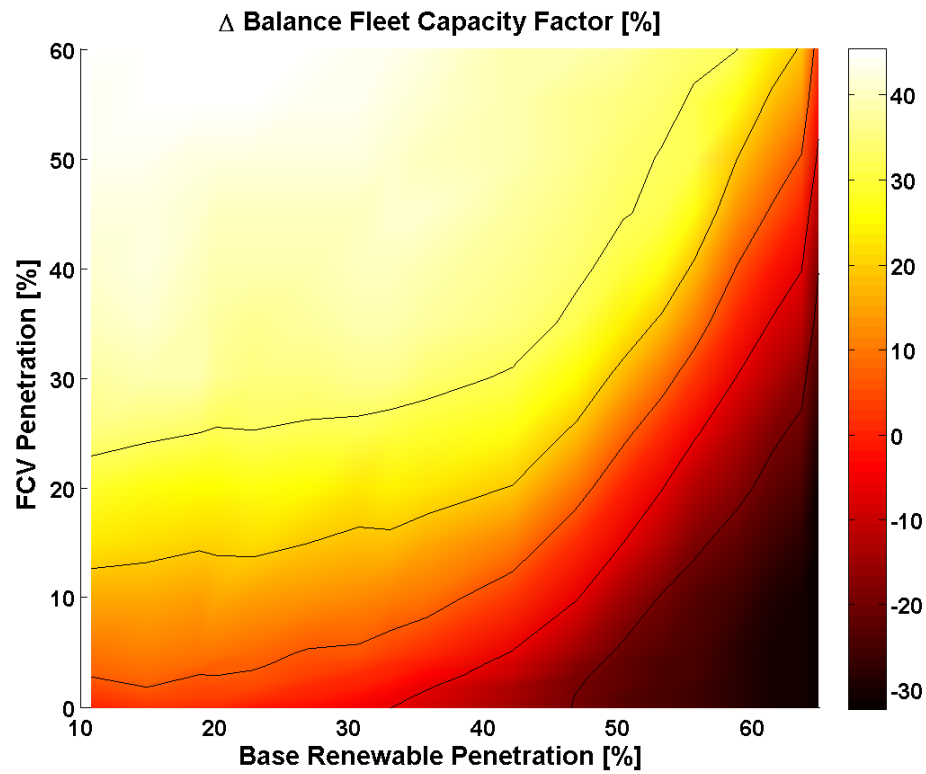


Figure 194 - Difference in Balancing Generator Fleet Capacity Factor from Reference Case: FCVs with 100% Electrolysis.

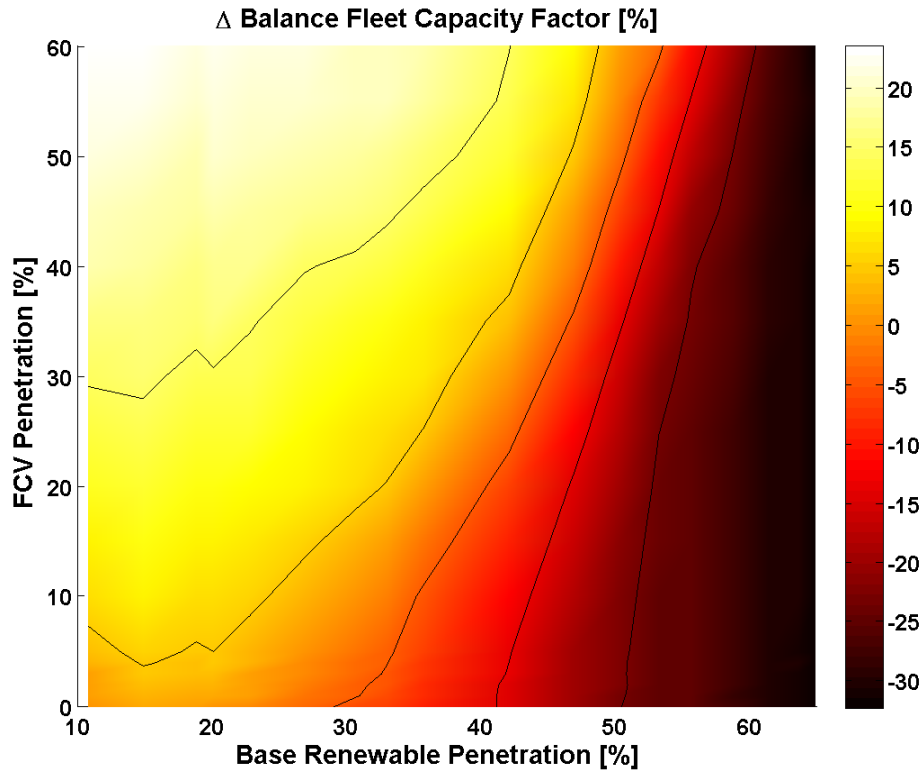


Figure 195 - Difference in Balancing Generator Fleet Capacity Factor from Reference Case: FCVs with 70% SMR and 30% Electrolysis.

The metric is the change in the balance generator fleet capacity factor from the reference case value. Note that these changes are not in terms of a percentage of the reference case value, but absolute changes for a quantity that is measured in percent.

The deployment of renewable resources such as wind and solar power serve to decrease the capacity factor of the balancing generator fleet in the absence of supporting technologies. This occurs since due to the temporal characteristics of wind and solar generation, installing increased renewable resource capacity does not reduce the peak net load demand after a certain threshold. This causes the balancing generator fleet capacity to remain high as the energy obtained from these power plants is decreased, decreasing the utilization of installed resources.

The deployment of alternative vehicles with grid-responsive load dispatch serves to counter this trend to the extent possible. For a given amount of installed renewable capacity, increases in the vehicle penetration level increase the balance generator fleet capacity factor. This effect is strongest at low renewable penetration levels, where renewable curtailment and net load variability are small, causing transportation loads to smooth out the diurnal load trends. As the amount of installed renewable resources increases and the extent of variability in the net load increases in tandem, dispatchable transportation loads still increase the balance generator fleet capacity factor but by a smaller extent compared to the no-transportation cases. This decrease in effectiveness occurs since periods occur when the transportation load is not large enough to raise the magnitude of the net load enough to cause the balancing generator fleet to operate above its minimum power level due to extreme renewable power generation.

Long-range BEV deployment is able to increase the balance generator fleet capacity factor by up to 24%, compared to 42% for FCVs with 100% electrolysis and 22% for FCVs with 30% electrolysis. These maximums occur at low base renewable penetration levels. At high base renewable penetration levels, FCVs with 100% electrolysis is able to maintain its effectiveness due to the presence of a very large load. Long-range BEVs and FCVs with 30% electrolysis are only able to limit the decrease in the balance generator fleet capacity factor due to renewable deployment due to the effects described previously.

6.1.2.5.3. Effects on Load-Following Power Plant Efficiency

Renewable generation-induced variability in the net load profile also affects the operating efficiency of load-following power plants. The efficiency of combustion-based power plants such as natural gas combined cycles and simple cycle gas turbines are dependent on their part-load operating condition, and tend to decrease in efficiency as these units operate at increasingly

sub-design power levels. In order to follow the variability of the net load demand induced by renewable generation, balancing generators will have to increase and decrease their power output while avoiding excessive shut-down and start-up events. Therefore, these units will be tasked with operating at lower part-load conditions for more hours out of the year compared to current operating paradigms.

The introduction of dispatchable vehicle-related loads can serve to reduce the impact of renewable resources on load-following power plant fleet efficiency. Load-following power plants meet the majority of the energy of the load demand, as opposed to peaking power plants, and therefore the efficiency of these units are important for fuel use and greenhouse gas emissions. These effects are presented regarding the balance fleet capacity factor with BEVs, FCVs with 0% SMR and FCVs with 70% SMR in Figure 196, Figure 197, and Figure 198, respectively.

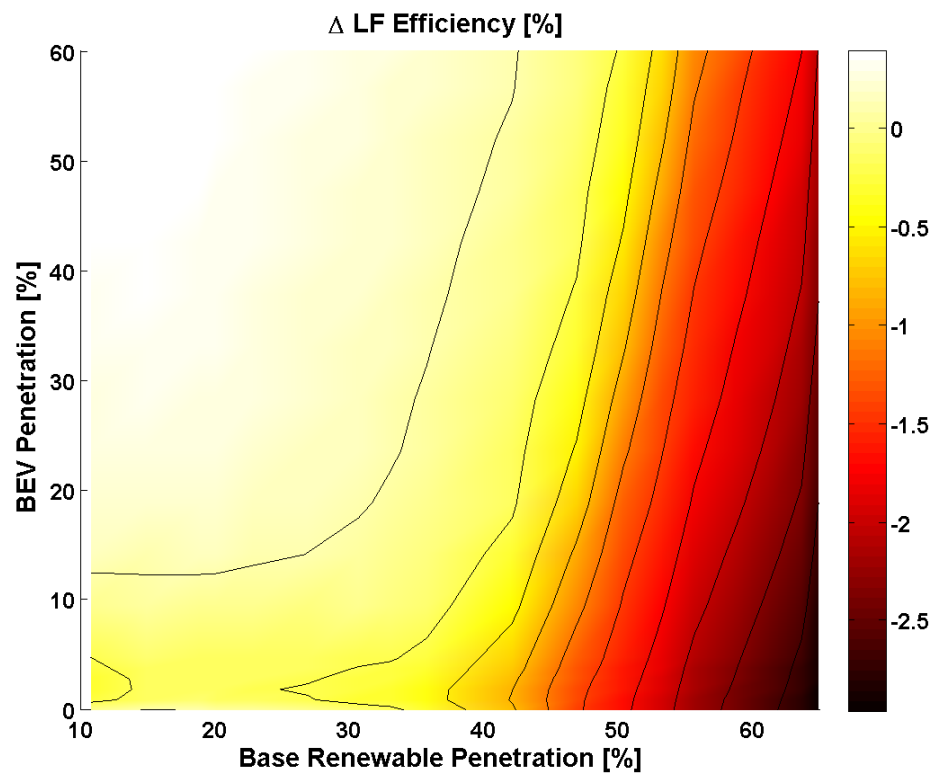


Figure 196 - Difference in Load-Following Power Plant Fleet Efficiency from Reference Case: Long-Range BEVs with Smart Charging

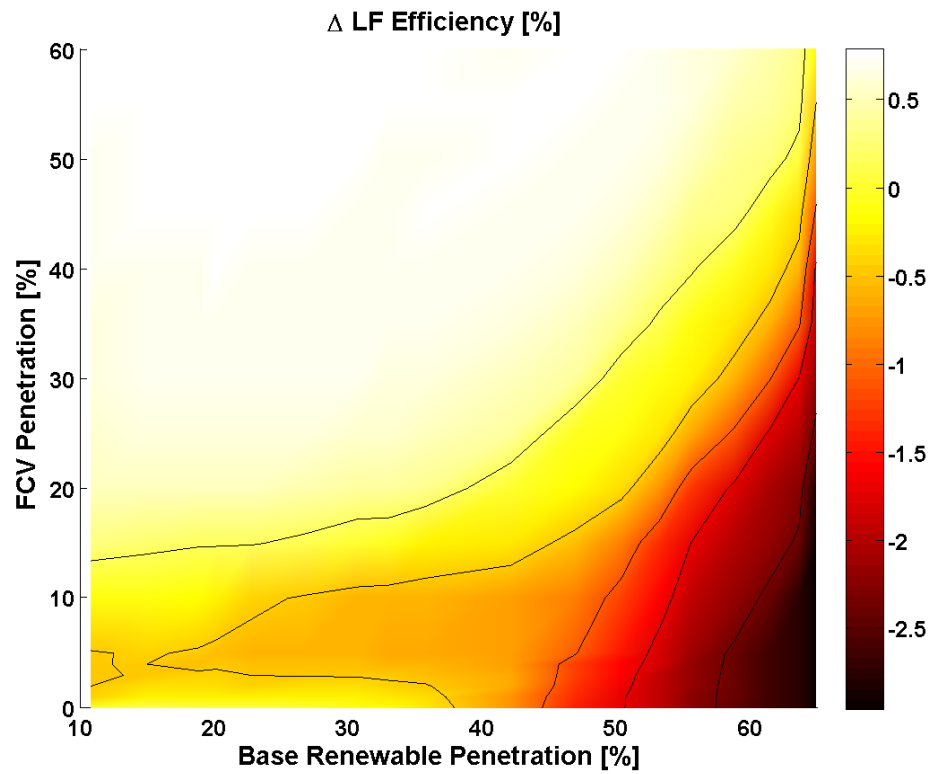


Figure 197 - Difference in Load-Following Power Plant Fleet Efficiency Factor from Reference Case: FCVs with 100% Electrolysis.

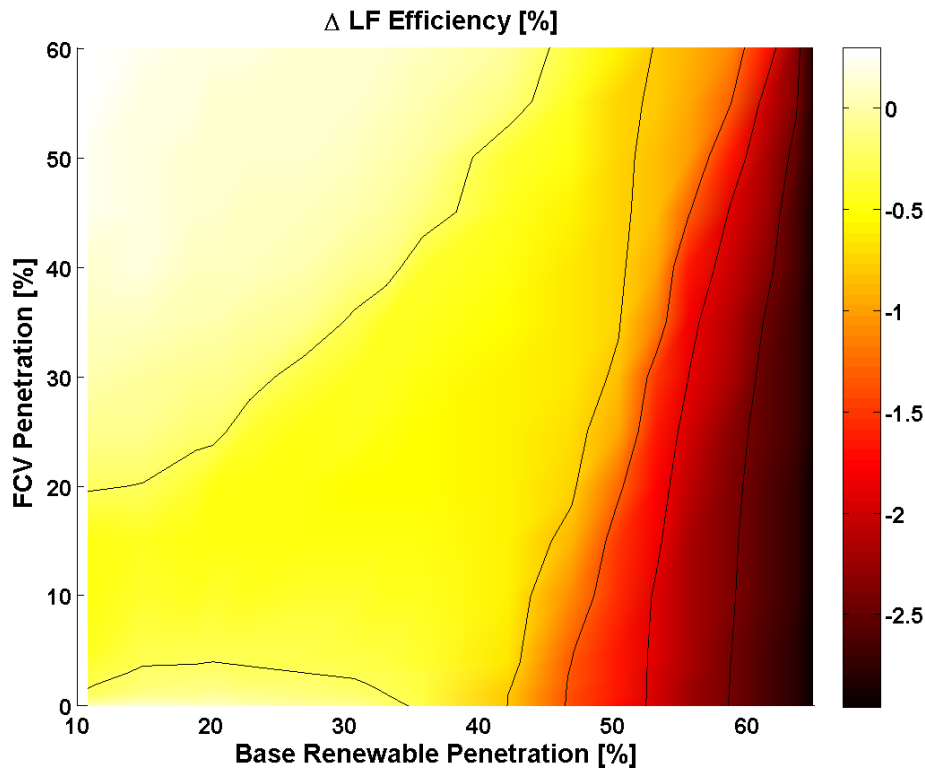


Figure 198 - Difference in Load-Following Power Plant Fleet Efficiency from Reference Case: FCVs with 70% SMR and 30% Electrolysis.

Again, the metric is the change in the load-following power plant fleet from the reference case value. Note that these changes are not in terms of a percentage of the reference case value, but absolute changes for a quantity that is measured in percent.

Similar to previous trends, grid-responsive, dispatchable transportation-related loads are able to limit the reduction in load-following power plant efficiency due to renewable generation variability. The addition of transportation loads in a net-load smoothing fashion allows load-following power plants to operate with more steady power profiles and closer to their design power level in a wide range of vehicle and base renewable penetration levels considered.

BEVs are able to increase load-following power plant efficiencies above the reference case value at low base renewable penetration levels up to about 30%. After this point, it becomes a matter

of limiting the decrease in load-following power plant efficiency as renewable variability becomes stronger. FCVs with 100% electrolysis are able to increase load-following power plant efficiencies over a larger range, but this is only due to the fact that it imposes a larger load (and therefore has more net-load smoothing capability) compared to BEVs and has increased flexibility of dispatch. At low vehicle penetrations, however, non-dispatchable loads due to other parts of the hydrogen supply infrastructure decrease load-following power plant efficiency for a small region. FCVs with 30% electrolysis follow a similar trend, but are less effective at high base renewable penetration levels due to the imposition of a smaller load.

6.1.2.5.4. Effects on Balancing Generator Start-Up Events

Renewable generation-induced variability in the net load profile can also require the start-up and shut-down of power plants on a more frequent basis due to large changes in the net load demand. Increased start-up events can cause increased degradation of balancing power plant equipment and increase both GHG and especially criteria pollutant emissions.

The introduction of grid-responsive transportation loads can also serve to counter this trend. These effects are presented regarding the balance fleet capacity factor with BEVs, FCVs with 0% SMR and FCVs with 70% SMR in Figure 199, Figure 200, and Figure 201, respectively:

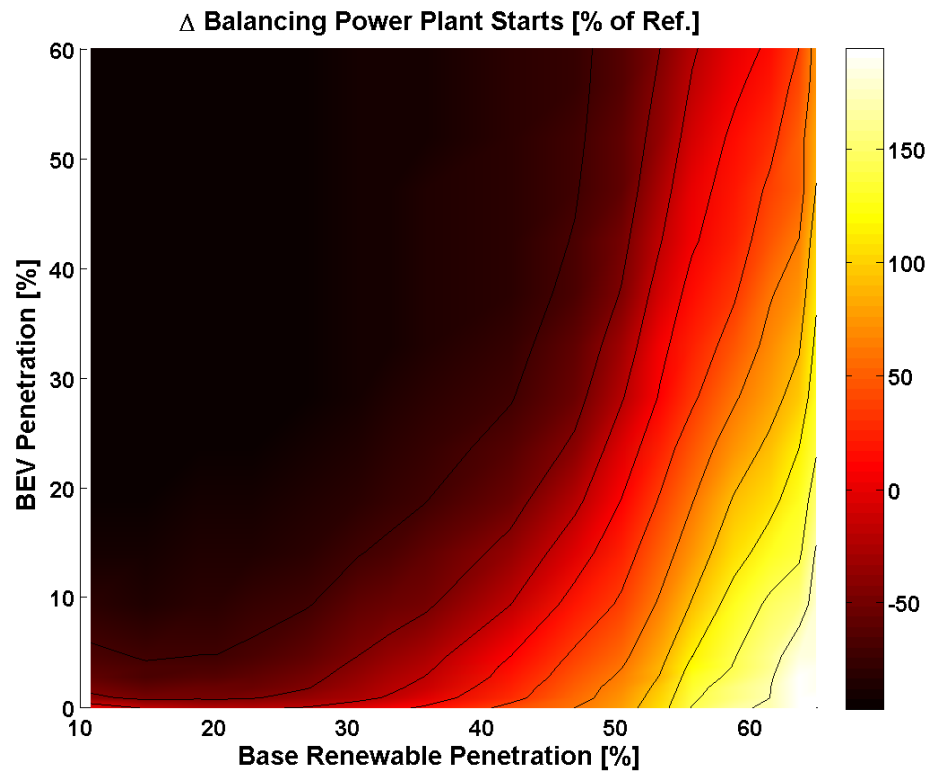


Figure 199 - Difference in Amount of Generator Start-Up Events from Reference Case: Long-Range BEVs with Smart Charging

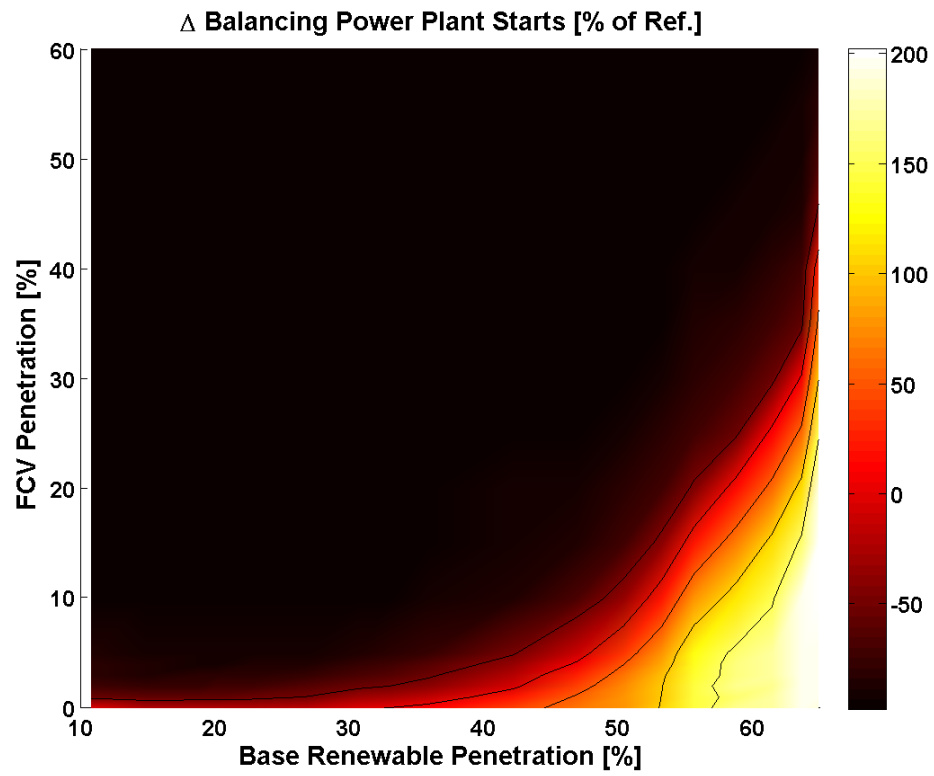


Figure 200 - Difference in Amount of Generator Start-Up Events from Reference Case: FCVs with 100% Electrolysis.

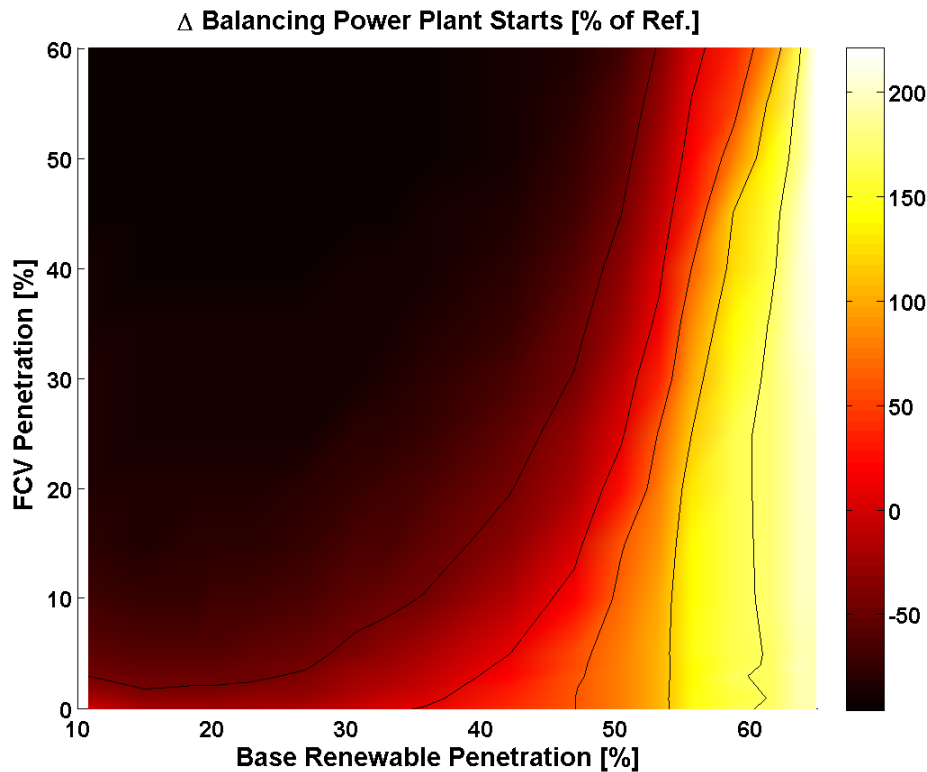


Figure 201 - Difference in Amount of Generator Start-Up Events from Reference Case: FCVs with 70% SMR and 30% Electrolysis.

The metric in this case is the change in balance generator start-up events (including peaking and load-following units) as a percentage of the reference case value.

Similar to the effects on other aspects of grid performance, the deployment of alternative fuel vehicles is able to counteract the impact of increasing variable renewable generation on the balancing generator fleet. In all cases, the deployment of grid-responsive transportation-related loads decreases the number of balancing generator start-up events. This serves to decrease degradation on load-following and peaking power plants and related start-up emissions. These effects are strongest at low base renewable penetration levels, where the degree of net load variability is low. At high base renewable penetration levels, larger vehicle deployments are

needed to reduce the number of start-up events due to extreme renewable power generation variability.

The extent to which these effects are present varies between the cases. Long-range BEV charging reduces the number of balancing generator start-up events over a large range of vehicle and base renewable penetration levels, but becomes limited by its low-load size rendering it unable to smooth the net load at high base renewable penetration levels. FCVs with 100% electrolysis are able to reduce the number of balancing generator start-up events by a large extent over almost the entire spectrum examined here, due to high flexibility and a large load size. FCVs with 30% electrolysis are slightly less effective than long-range BEVs in this respect, also due to a limited dispatchable load size.

6.1.2.5.5. Results for the Levelized Cost of Electricity

The trends presented previously regarding the cost of energy per capita regarding the deployment of long-range BEVs and FCVs with a GHG-optimized infrastructure configuration are strongly influenced by the effects that supporting these vehicles, along with renewable deployment, have on the cost of electricity. The effects of adding these transportation-related loads alter many aspects of electric grid design and operation. Many of these effects have direct implications for the cost of electricity. Some of these effects were explained in the previous section.

The change in the levelized cost of electricity from the reference case value due to long range BEV deployment is presented in Figure 202 and for FCVs with a GHG-optimized infrastructure configuration as a difference from the BEV value is presented in Figure 203:

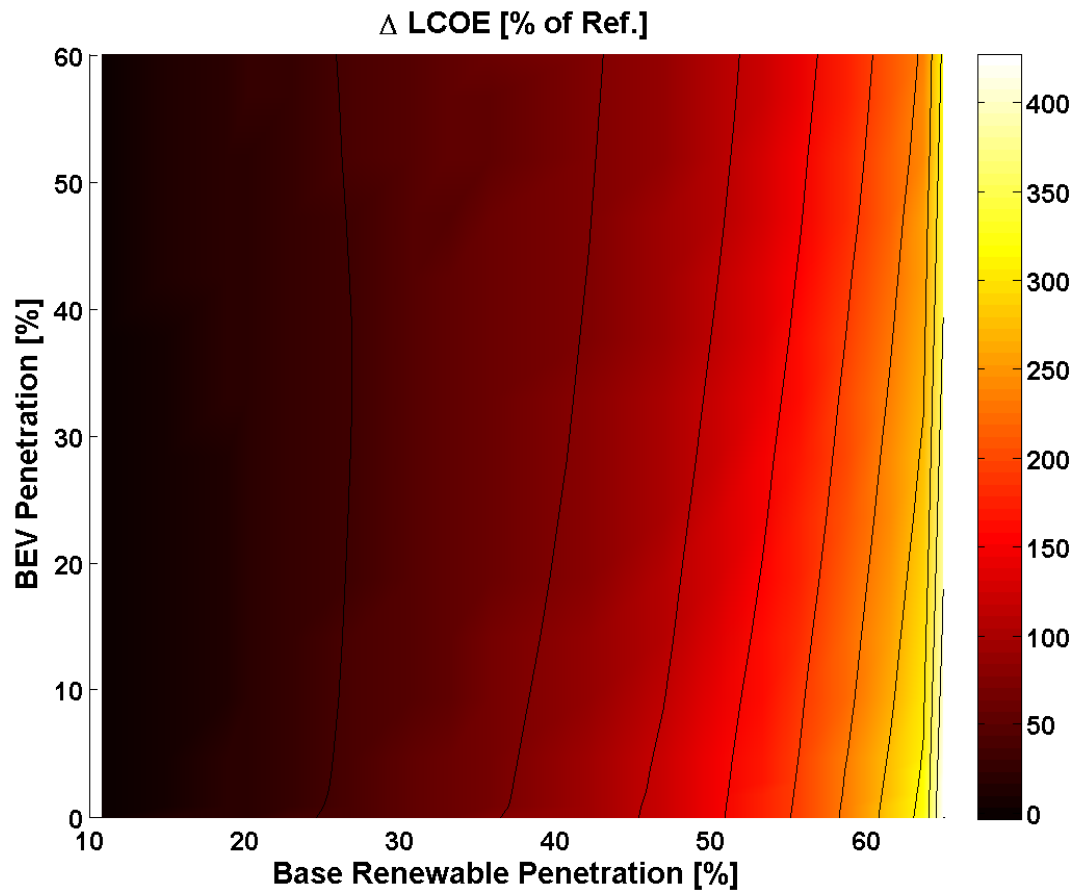


Figure 202 - Change in the Levelized Cost of Electricity from the No-Transportation Cases: Long-Range BEVs

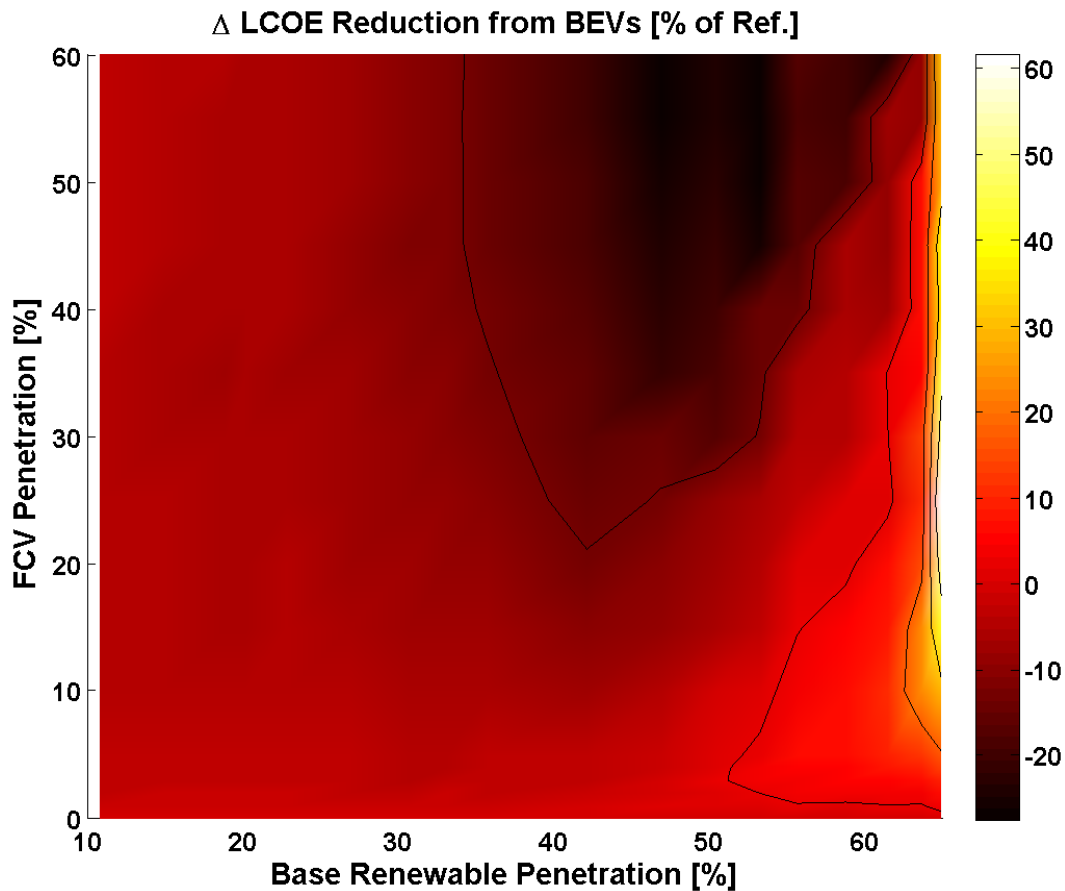


Figure 203 - Change in the Levelized Cost of Electricity from the Reference Case Value relative to BEV value: GHG-optimized FCV deployment

BEVs change the cost of electricity by smoothing out the net load profile on the electric grid, leading to higher balance generator fleet capacity factors, decreased wear and tear, and increased balancing fleet efficiency. While these effects are very important, from an economic perspective, they are relatively small compared to influence of the instant cost of renewable resources, especially solar power, as evidenced by the slope of the contour lines in Figure 202. Small changes in the cost of electricity, however, have significant impacts on the cost of energy per capita. This is due to the fact that electricity constitutes a large fraction of total consumer energy use, and becomes a larger fraction as the energy intensity of the transportation sectors decrease due to alternative vehicle deployment.

The effect of deploying FCVs with a GHG-optimized infrastructure configuration on the cost of electricity varies considerably depending on production mix. The GHG-optimized configuration relies strongly on steam-methane reformation for a large range of base renewable penetration levels and vehicle penetration levels. Steam methane reformation has only a weak interaction with the electric grid, therefore in these regions, transportation-based electric loads are primarily due to dispensing and distribution loads, which are non-dispatchable. Therefore, for regions of the spectrum when steam methane reformation is the dominant form of hydrogen production, FCVs do not provide many benefits to grid operation and therefore do not reduce the cost of electricity relative to BEVs. At high base renewable penetration levels when electrolysis is not used, the advantage of BEVs in this respect is increased. Steam methane reformation, however, is a very low-cost technology and allows the cost of energy per capita to remain within reason relative to that for BEV deployment until electrolysis begins to become preferred.

The primary interaction occurs at high base renewable penetration levels in regions where the production mix begins to switch towards higher fractions of electrolysis. As electrolysis becomes preferred from a GHG-minimizing standpoint to make use of excess renewable generation, the trend reverses. The availability of more load for dispatch and increased flexibility relative to grid-responsive BEV charging allows FCV deployment to provide increased benefits for the electric grid that results in cost of electricity reductions. At the edge of the base renewable penetration level spectrum considered in this study, FCVs reduced the levelized cost of electricity by up to 61% of the reference case value compared to BEVs. This is what allows the economic impact of FCVs at the high end of the base renewable penetration range to remain within reason relative to BEVs, and offsets the cost of a more expensive and slightly more energy intensive hydrogen infrastructure.

6.1.2.6. Discussion – Implications for Policy and Energy Use Patterns

When combined sector performance is considered, both FCVs and BEVs are equally good options for complementing renewable generation to decarbonize societal energy use. The dotted lines in Figure 186 and Figure 187 represent the current trajectory of California's grid renewable and alternative vehicle deployment policy. The state is on track for maximum GHG reductions using either technology only if the potential benefits of the interactions described here are practically realized. The common thread is the need for coordinated deployment between decarbonizing technologies in the transportation and the electricity sector. It is not beneficial to continue to set deployment targets without consideration of co-dependent sectors.

The primary difference between these technologies is not as much in technical benefit or economic impact, but in their requirements for energy use patterns and system operation to practically realize these benefits. Each technology places different requirements on consumers and grid operators to do so.

Using BEVs with optimized charging requires consumers to become more involved with grid operations while meeting their transportation needs. Since the dispatch of grid resources is mostly handled in a day-ahead market, consumers would need to schedule their vehicle as a dispatchable resource at least one day ahead of time and adjust their travel patterns accordingly. Without scheduling, BEVs would only affect the real-time electricity market and would not significantly affect the dispatch of other grid resources to provide GHG emission reductions. On the other hand, the use of BEVs requires relatively minimal up-front investment from companies and government, since supporting infrastructure mainly requires an upgrade of existing infrastructure. This renders BEV deployment easier to initiate in the short-term as it requires

lower initial monetary commitment, but potentially more difficult to realize ideal benefits in the long term if consumers do not tailor their behavior.

Practical realization of FCV usage benefits has an inverse behavior. These vehicles have long driving range and can be used similarly to gasoline vehicles and consumers can use their vehicles freely. Grid operators can also dispatch infrastructure electric loads such as central electrolysis as needed, and can schedule these resources into the day-ahead market to affect the dispatch of other grid resources. On the other hand, up-front investment in hydrogen supply infrastructure is significantly higher than that for BEVs since it entails the installation of all-new equipment. This requires an increased commitment from automakers, industry, and government in the near term with the promise of ease of management and realization of ideal benefits in the long term.

Both BEV and FCV technologies contribute near equally to decarbonizing energy use. With the sustained attention of policy to decarbonizing the electric grid and the developing bio-hydrogen sources, adoption of either or both of these two technologies will be directed by consumer preferences associated with, for example, the choice of range and convenience of fueling and charging.

6.1.2.7. Summary and Conclusions

6.1.2.7.1. Summary

A study was performed that compared the effects of deploying battery electric vehicles (BEVs) and fuel cell vehicles (FCVs) with an increasingly renewable electric grid on the holistic emissions and economic performance of the combined electricity-transportation system, spanning a wide range of renewable penetration levels and vehicle penetration levels. This was performed for GHG-optimized as well as non-optimal hydrogen infrastructure configurations to examine the major impacts on the system, and for different but constant hydrogen production

mixes to examine the intricacies of the impacts on electric grid resource operation. Finally, the implications of these results for policy and implementation challenges were discussed.

6.1.2.7.2. Conclusions

The key conclusions are as follows:

1. The GHG reduction potential of BEVs and FCVs are similar under careful infrastructure planning. Despite large differences in the fueling pathway and energy requirements for relying on the different vehicle types, the GHG reduction potential for both BEVs and FCVs are similar if the hydrogen infrastructure is carefully coordinated with renewable deployment. This occurs since the increased dispatchability of the hydrogen electrolysis load compared to the BEV charging load allows the system to more effectively match generation and load profiles, making use of renewable generation that would otherwise be curtailed. The fraction of electrolysis the hydrogen production mix must be sized carefully such that the tradeoff between increased electric load and utilization of excess renewable generation is balanced for each renewable penetration level.

2. FCV deployment exhibits slightly increased costs of energy per capita compared to BEVs under careful infrastructure planning. Despite the large differences between the infrastructure cost requirements for BEVs and FCVs, the cost of energy per capita when using FCVs is only slightly higher than that for BEVs. The dispatchability of the hydrogen electrolysis load allows for more steady operation of balancing generator resources, giving rise to a decrease in the cost of electricity relative to that when using BEV deployment. This partially offsets the increased infrastructure costs required for FCV utilization.

6.2. Electricity and Water Supply

Currently, sections of this text are described in publications that have been currently submitted to refereed journals as follows:

- **Tarroja, B.**, AghaKouchak, A., Samuelsen, S., Sobhani, R., Feldman, D., Jiang, C.S., “*Evaluating Options to Stabilize the Water-Electricity Nexus in California: Part 2 – Greenhouse Gas and Renewable Energy Utilization Impacts*”, Science of the Total Environment, 2014. **Submitted as of March 2014**

6.2.1. Water Supply Stabilization Measures and the Electric Grid

6.2.1.1. Literature Review

Concerns about climate effects on water availability combined with increasing demands in various regions are driving interest in diversifying the water supply portfolio. Many regions in the world are expected to exhibit decreased water availability due to the impacts of climate change on regional hydrology and weather patterns [239-245]. Coupled with population growth and projected increases in demand in many regions, the need for more prudent water management strategies and options for usable water supply has been identified. However, reliance on the historical paradigm of precipitation-based and groundwater supplies may not be enough to meet increasing demands. Many alternative options for water supply are currently available, including but not limited to: urban water conservation, purification and reuse of treated wastewater, and desalination of seawater or brackish water using membrane or thermal processes. The accessibility of these options varies significantly by region, and their implications for water availability, energy usage, and greenhouse gas emissions depend strongly on the characteristics of a given region.

Certain aspects of the energy consumption and greenhouse gas impacts of different options to stabilize the water supply have been characterized. Many studies focus on the energy

requirements of the fundamental physical processes and operation of associated facilities utilizing these options, and their subsequent economic impact.

Characterizing and reducing the energy consumption of desalination processes has been an active topic of interest. Al-Karaghoul [106] provided a review of the energy consumption of various desalination processes, with costs characterization using conventional and different renewable energy resources. Subramani [334] also outlined devices and novel technologies to minimize membrane desalination energy consumption, as well as a short discussion of renewable energy utilization. Keisime [334] compared the economics of different seawater desalination processes in Australia in the context of available waste heat and materials costs, concluding that membrane desalination was the most cost effective option due to the lower cost materials, even with the presence of a carbon tax. Additionally, many studies have investigated the concepts for novel desalination plant and process configurations, including energy recovery and integration with dedicated renewable energy resources for reducing fossil fuel energy consumption and related emissions [258, 335-339].

The energy and emissions footprint of water reuse has also been examined. The process energy consumption and diurnal behavior of water reuse processes (microfiltration, reverse osmosis, advanced oxidation) have been examined by Sobhani [111], taking into account real-world plant operating constraints. An review of the energy intensity of water reuse and recovery was also given by [340] for in-operation systems, ranging from between 0.33 to 1.86 kWh/m³ depending on pumping requirements and system topography. Kajenthira [341] cites the lower energy consumption of wastewater reuse as rationale for prioritizing this option over desalination.

However, the author did not consider the additional trunk line construction cost for non-potable or indirect potable reuse of reclaimed water.

While literature exists on the energy consumption of different options, most of these studies focus on characterizing and comparing the energy consumption of the fundamental physical processes in isolation. Little consideration is given to impacts arising from the manner in which these options impact the energy intensity of the water supply system (conveyance, etc...) that they are implemented into and the associated emissions impacts. These systematic effects are equally as important as the fundamental processes in influencing the holistic energy and emissions impact of securing the water supply with different options.

Additionally, the emissions impacts of deploying different options have typically been calculated using static factors for linking energy consumption with emissions, and have not captured the sensitivity of electric grid operation and evolution. This is especially important in the context of hydropower contribution uncertainty under climate change.

Finally, studies which examine renewable energy integration with water supply options also assume that renewable resources can be solely dedicated to these loads. This is not the case in practice, as renewable energy resources installed on the grid will serve the bulk grid load, therefore the emissions intensity of water supply options must take this into account. Few studies have compared different options on a basis that takes these sensitivities into account.

Capturing the scale of the options required to stabilize surface water reservoir levels was the focus of the first part of the study. This analysis is aimed at the following for this system:

- Comparing the **holistic** energy and emissions impacts of option portfolios that successfully stabilized major surface water reservoir levels, under historical (baseline) and climate-change augment conditions, taking into account operational effects on the water supply system, accurate scale, and electric grid evolution.
- The implications of securing the surface water reservoir levels for the ability of the system to meet renewable energy utilization goals.

With this comparison, quantitative insight into the factors that must be taken into account when choosing between different water supply options in the holistic context can be obtained.

6.2.1.2. Approach

6.2.1.2.1. Water Scenarios for Analysis and Renewable Energy Rollout

This study takes the water supply stabilization option portfolios which were able to successfully stabilize reservoir levels as determined in Section 5.2., and determines their energy and emission impacts as well as their implications for renewable energy utilization. This is conducted for each successful portfolio and renewable capacity combination. For reference, these cases are presented in Table 65 for baseline conditions (BAS) and in Table 66 for climate change augment conditions (CCHa):

Table 65 - Successful Water Stabilization Portfolios - Baseline Conditions, Capacities in Mm³/d

<u>Designation</u>	<u>UC</u>	<u>TDw</u>	<u>TD</u>	<u>MD</u>	<u>PR</u>
TD	0.00	0.00	7.60	0.00	0.00
MD	0.00	0.00	0.00	7.60	0.00
MD (SC)	0.00	0.00	0.00	7.10	0.00
PR	0.00	0.00	0.00	0.00	7.00 (38%)
UC/PR (GH)	6.83 (100%)	0.00	0.00	0.00	0.55 (3%)
MD/UC	6.83 (100%)	0.00	0.00	0.65	0.00

Table 66 - Successful Water Stabilization Portfolios - Climate Change Augment Conditions, Capacities in Mm3/d

Designation	UC	TDw	TD	MD	PR
TD	0.00	0.00	34.00	0.00	0.00
MD	0.00	0.00	0.00	34.00	0.00
MD (SC)	0.00	0.00	0.00	30.50	0.00
MD/UC	9.50 (100%)	0.00	0.00	19.50	0.00
MD/PR	0.00	0.00	0.00	7.20	18.44 (100%)
P1	9.50 (100%)	0.00	0.00	7.40	18.44 (100%)
P2 (GH)	9.50 (100%)	3.63 (100%)	0.00	5.00	18.44 (100%)

The GH case represents the portfolio which was configured for minimum greenhouse gas emissions, as determined by the impacts identified in the results section.

For each successful portfolio, the time-resolved electric load profile is calculated and added to the bulk electric load demand profile for California, as obtained from CAISO data for the year 2005 [138]. This is conducted for increasing amounts of renewable generation, based on projections by the California Public Utilities Commission (CPUC) up to a 33% base renewable penetration level [298], but adjusted for grid constraints and curtailment. The base renewable penetration level represents the fraction of the electric load demand that is served by renewable resources without load from transportation or water supply sectors in excess of historical trends. Beyond the 33% base renewable penetration level, the rollout is based on capacity limits and capacity factors of available renewable resources. The renewable mix used in this study is presented in Figure 204:

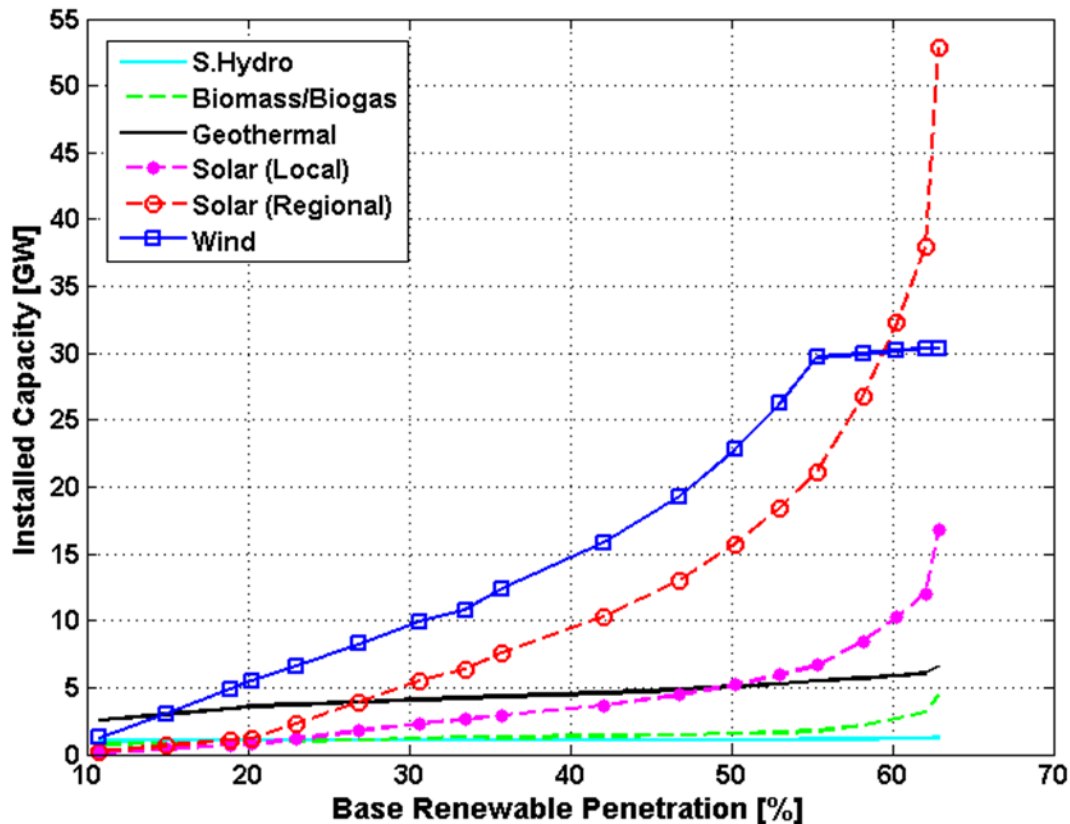


Figure 204 - Renewable Mix vs. Base Renewable Penetration Level under Baseline Conditions

Without any additional load, the base renewable penetration level under baseline conditions spans from 10.7% to about 64.8%.

6.2.1.2.2. Grid Input Modifications for Climate Change Conditions

For the climate change augment conditions, which represents the 2040-2050 time period, the population of the state is expected to increase from about 35.2 million (2005) to 49.1 million (2045). Therefore, the raw electric load demand scales with population accordingly for these conditions, being increased by a factor of 1.39. The temporal profile of the raw load demand, however, remains the same. Due to this load increase, the base renewable penetration under these conditions is lower for a given installed renewable capacity amount.

Under the climate change augment conditions, the reservoir inflows are affected, which also affects the water available for hydropower generation. The hydropower module used in the HiGRID model takes in a bulk stream flow vector, the details of which are presented in [342]. To handle this effect in our study, at each time step, the difference between the aggregate reservoir inflows between baseline and climate change augment conditions was calculated and normalized by the baseline condition value. This scaling profile is then applied to the bulk stream flow vector used for the baseline conditions to create a bulk stream flow vector for climate change augment conditions. This is then used as the input to the HiGRID hydropower module.

6.2.1.2.3. Metrics

For each successful water option portfolio and renewable capacity combination, the following metrics are calculated to evaluate the energy and emissions effects of implementing these options.

Greenhouse Gas (GHG) Emissions: This refers to the total greenhouse gas emissions emitted annually by the combined water supply and electricity sectors. This includes all direct emissions from water stabilization options, and all emissions due to generation resources on the electric grid. The electric loads associated with water stabilization options do not cause direct emissions, rather, these are accounted for by increasing the electric load on the grid and therefore a change in electric grid greenhouse gas emissions. This accounts for CO₂, N₂O, and CH₄ emissions, and is presented in million metric tons of CO₂ equivalent (CO₂e).

Incremental GHG Intensity: This refers to the incremental increase in greenhouse gas emissions to provide one cubic meter of water (or displace an equivalent demand) from the different individual options, taking into account direct and systematic energy impacts.

Renewable Penetration Level: This refers to the fraction of the total electric load demand (including that due to water supply stabilization options) that is served by renewable resources. This is important for measuring the progress towards meeting the Renewable Portfolio Standard goals of the state or a given region.

6.2.1.3. Results

6.2.1.3.1. Effects of Climate Change on Grid Performance

Before a discussion of the greenhouse gas effects of implementing the option portfolios that successfully stabilized surface water reservoir levels identified in Section 5.2., it is important to discuss the differences between the no-option cases for the baseline and climate change augment conditions. The greenhouse gas emissions as a function of installed renewable capacity for the no-option cases and both hydrology conditions are displayed in Figure 205:

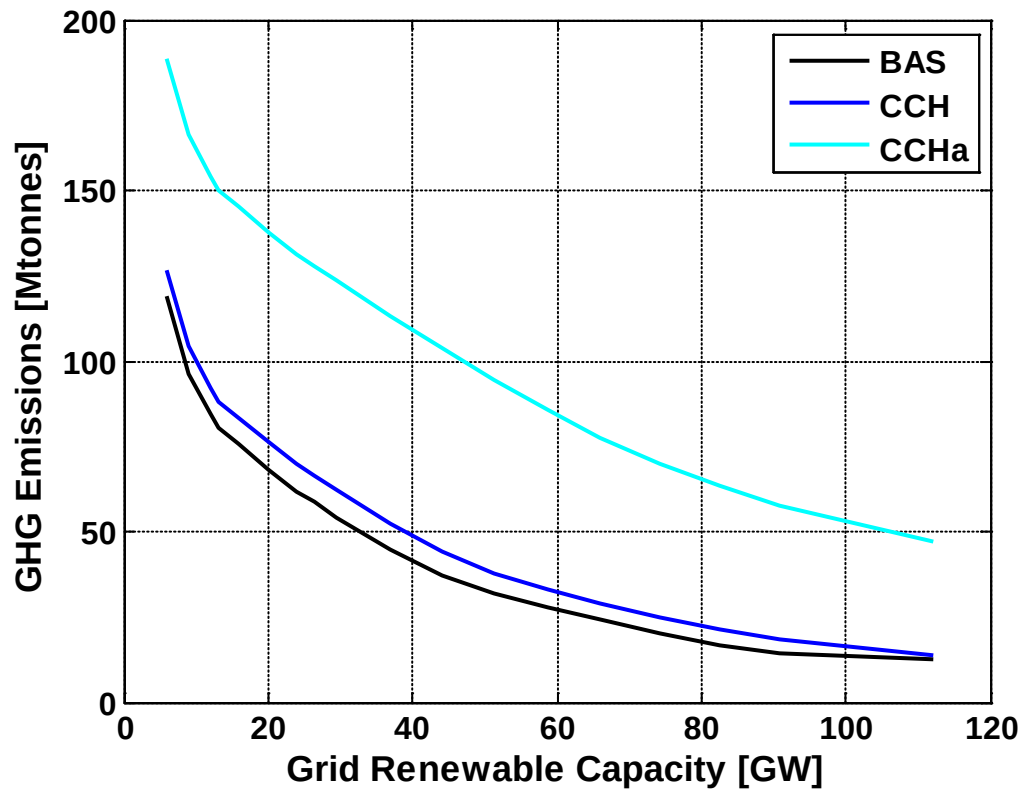


Figure 205 - No-Option Combined Water-Electricity Greenhouse Gas Emissions

Three cases are displayed. The BAS case refers to baseline conditions, the CCH case refers to climate change augmented inflow conditions but no electric load demand growth, whereas CCHa includes both augmented inflow and demand growth. As expected, emissions decrease with increasing installed renewable capacities for all cases.

The CCH case shows only slight increases in GHG emissions compared to the BAS case. This increase is primarily due to the reduction in hydropower generation, brought about by reduced reservoir inflow. The deficit in generation must be compensated for by other resources on the grid, primarily natural-gas fired load-following power plants, increasing fuel consumption and therefore emissions. However, while the reduction in inflow due to climate change in this region may be large – on the order of 30-35%, hydropower only comprises a fraction of the grid energy

mix. The increase is between 7.83 Mtonnes of CO₂e at low renewable capacities and 4.21 Mtonnes of CO₂e at high renewable capacities. While this can be up to 7% of the combined system greenhouse gas emissions, it is small compared to the effect of electric load demand growth due to population. This is evidenced by the difference between the CCHa and CCH cases.

An additional aspect to consider is the effect that climate change inflows will have on the dispatch of hydropower. Hydropower serves an important role on the electric grid by providing load following generation to balance the electric load demand and ancillary services capacity to maintain grid reliability. With increased renewable capacity, these functions are more valuable due to wind and solar power intermittency. Therefore, the reduction of reservoir inflow does not only affect greenhouse gas emissions, but also the dispatch of hydropower resources. Sample profiles for the dispatch of hydropower generation at low and high installed renewable capacities are presented in Figure 206 and Figure 207, respectively:

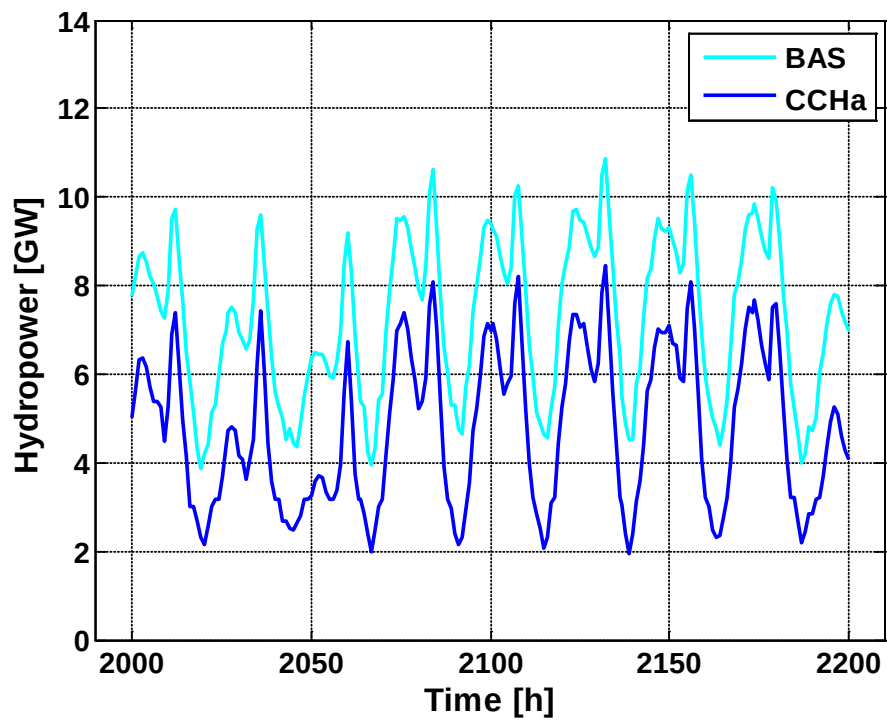


Figure 206 - One-Week Hydropower Profiles for BAS and CCHa Cases - 5.9 GW RE

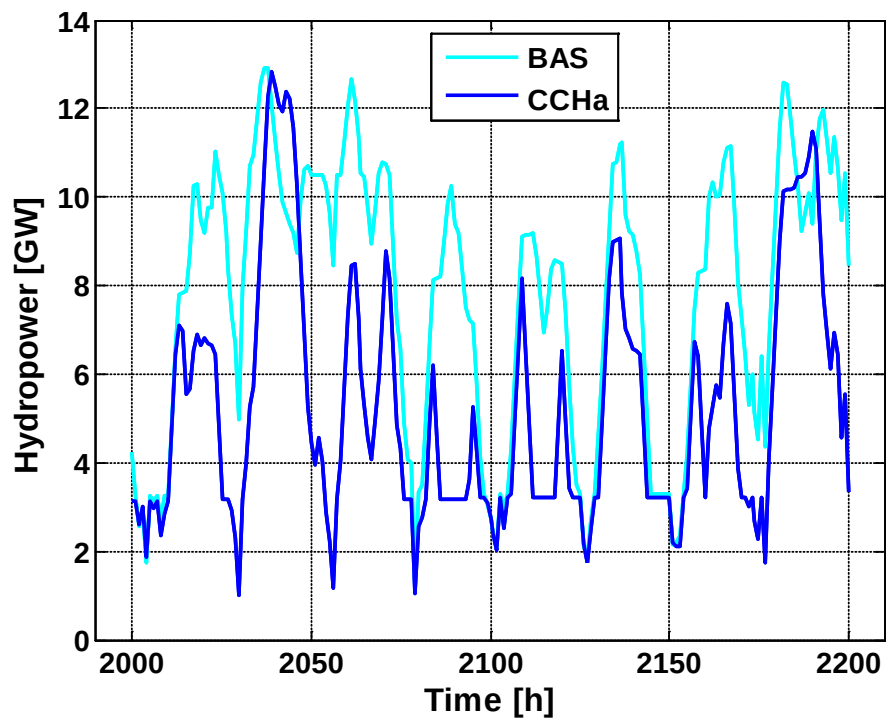


Figure 207 - One-Week Hydropower Profiles for BAS and CCHa Cases - 82.5 GW RE

With low renewable capacities installed, the behavior of hydropower generation under climate change augment conditions is the same as that under baseline conditions, but scaled down. This is because the variability that hydropower must balance is small. At high renewable capacities, however, the manner in which hydropower plants are dispatched under reduced inflow is no longer a scaled down version of that under baseline inflow. In order to provide ancillary services to maintain grid reliability while balancing renewable intermittency with reduced inflow, these power plants must be dispatched differently. A full analysis of these effects is beyond the scope of this work, however, this behavior implies that the management of hydropower plants and their role on the electric grid may need to be altered under climate change augment conditions. This is a subject of future work.

6.2.1.3.2. Incremental GHG Emissions of Water Supply Stabilizing Options

To understand the results for the effect of implementing the water supply option portfolios that successfully stabilized reservoir levels on greenhouse gases, it is important to understand the impacts of the individual options that compose those portfolios. This includes not only their direct effects on emissions through their specific processes, but also their effect on the electric loads associated with conveyance, treatment, distribution, and wastewater treatment.

A breakdown of the components of the greenhouse gas impacts for implementing each of the individual options evaluated in this study is displayed in Figure 208, for a 10.7% grid renewable penetration level. It is important to note that since many of the emissions due to these options are through their effects on the electric grid, the renewable penetration level of the electric grid influences these results. The southern California-biased membrane desalination option is also added for comparison. Each option affects total system greenhouse gas emissions through their effect on different components. These are described as follows:

- **Direct:** Greenhouse gas emissions that are directly emitted from the option processes
- **Plant:** Emissions due to the additional electric loads placed on the grid from the option processes
- **Conveyance:** Effect on emissions due to the displacement of water conveyance loads (i.e. pumping)
- **Treatment:** Effect on emissions due to the displacement of water pre-treatment loads
- **Distribution:** Effect on emissions due to the displacement of loads associated with distributing water to end users
- **Wastewater Treatment (WWT):** Effect on emissions due to changes in wastewater treatment plant loads.

Some of the greenhouse gas emissions intensity components for a given measure can be negative. This indicates that greenhouse gas emissions are reduced due to the effects of individual options on these components. For example, an acre-feet of water conserved in a certain region is one which does not have to be pumped or conveyed to that region, reducing the associated electric load and therefore greenhouse gas emissions. These effects will be described in detail for each option.

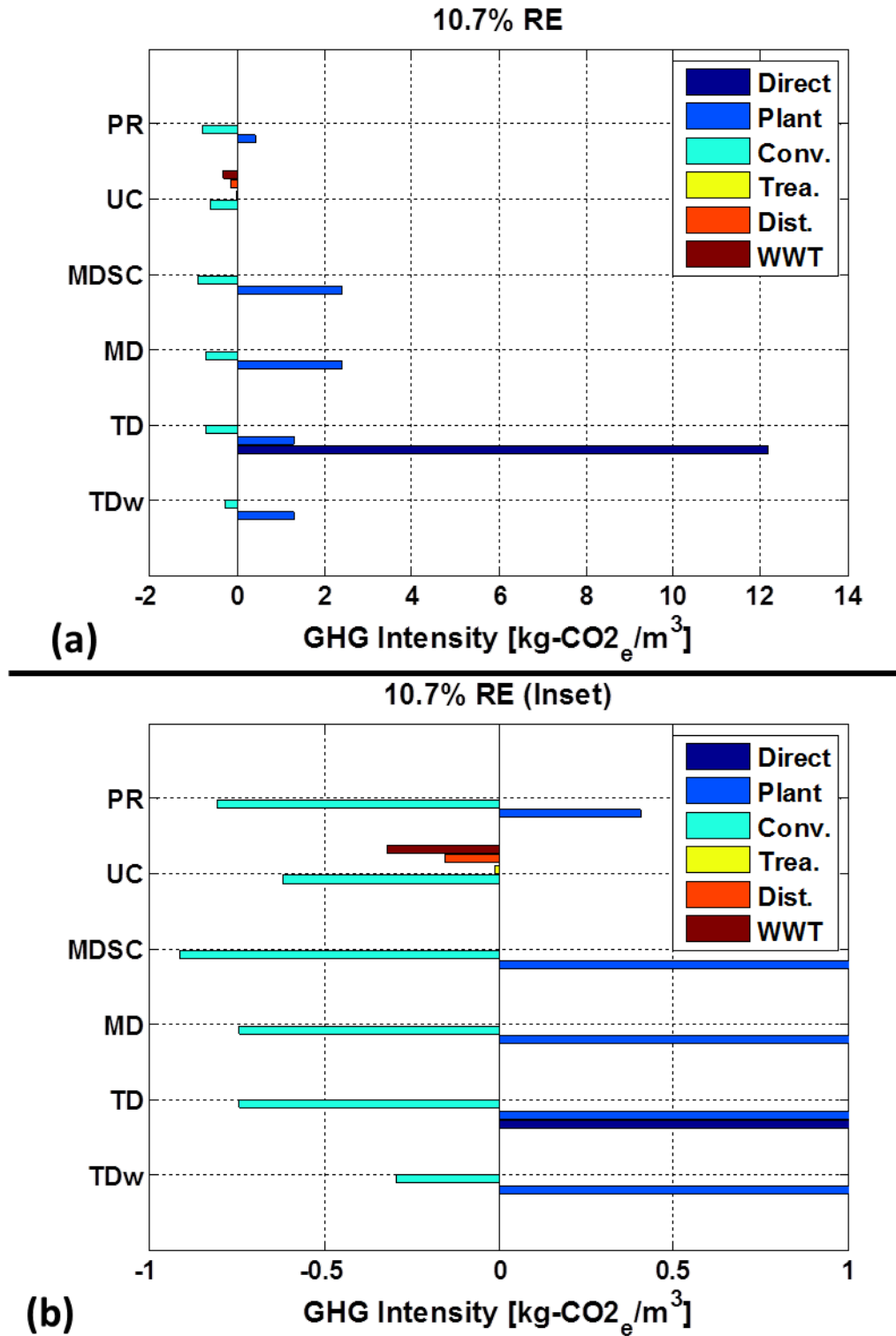


Figure 208 - Greenhouse Gas Intensity Breakdown for Different Individual Options at a 10.7% Grid Renewable Penetration Level (a), Inset (b)

Water reuse (PR) produces greenhouse gas emissions due to the electric loads associated with the processes: microfiltration, advanced oxidation processes, and reverse osmosis. Per cubic meter of water produced from this option, these plant loads contribute about 0.406 kg CO₂e at this renewable penetration level. For the California system, however, the majority of wastewater treatment plant capacity is located in the southern region. Conveying water to this region is very energy intensive. By meeting local demand with water reuse, less water must be pumped into the region, reducing electric loads and greenhouse gas emissions by about 0.808 kg CO₂e. Therefore, the net effect of implementing this option on greenhouse gas emissions is actually negative. This measure does not affect other components, however, since it does not modify the raw water demand.

Urban water conservation (UC) has significant benefits for emissions due to the effects it has on the water supply infrastructure electric loads. Conserving water has no direct or process emissions. Furthermore, a given amount of water conserved in a given region is one which does not have to be conveyed into the region, treated, distributed to end users, and flowed through wastewater treatment plants. Therefore, this option displaces electric loads from all of these processes, contributing to a net negative effect on greenhouse gas emissions. The benefit of displacing conveyance loads for this option is not as large as that for water reuse due to differences in the spatial distribution of where it is implemented.

Membrane desalination (MD) also produces greenhouse gas emissions due to electric loads associated with the seawater reverse osmosis process, which is relatively energy intensive compared to the other options. This component contributes 2.42 kg CO₂e per cubic meter at this renewable penetration level, but displaces conveyance loads due to a large concentration of

coastal population in southern California, reducing emissions by 0.743 kg CO₂e per cubic meter. The net effect is still positive, however. When membrane desalination capacity is more biased towards the southern California region (MDSC), the emissions reduction due to conveyance is increased to 0.914 kg CO₂e per cubic meter, but the net effect is still positive.

Thermal desalination with direct natural gas (TD) produces the largest emissions contributions. To provide heat for the multi-effect evaporation (MEE) process, a relatively large amount of natural gas must be burned, resulting in large direct emissions of about 12.2 kg CO₂e per cubic meter. Electric loads due to pumping loads in the plants themselves also contribute 1.29 kg CO₂e per cubic meter, while displacement of conveyance loads is the same as that for membrane desalination since it is based on urban coastal population distribution.

Thermal desalination with waste heat (TDw) has the same plant-based emissions as that with natural gas, but has no direct emissions since no additional fuel is being burned. This option has a reduced beneficial effect on displacing conveyance loads, however, since a large fraction of the waste heat potential is in the central and northern California regions, where the conveyance load is small.

The relative ordering of the individual options remains the same as the renewable penetration level of the electric grid is increased. All of the component effects of each option, except that of direct emissions, scale with grid renewable penetration since they are based on electric loads. The breakdown of the components of the greenhouse gas impacts for implementing each of the individual options at a 20.1% and 50.3% grid renewable penetration level is presented in Figure 209 and Figure 210, respectively. The inset figures are shown, since the scale of the direct

emissions due to thermal desalination with natural gas does not change with renewable penetration.

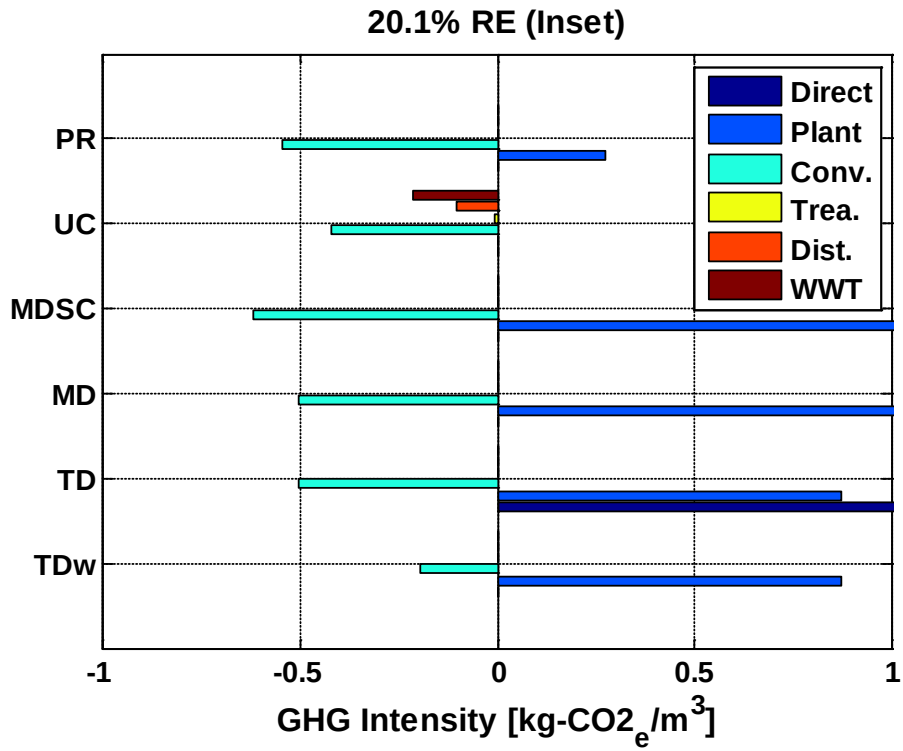


Figure 209 - Greenhouse Gas Intensity Breakdown for Different Individual Options at a 20.1% Grid Renewable Penetration Level

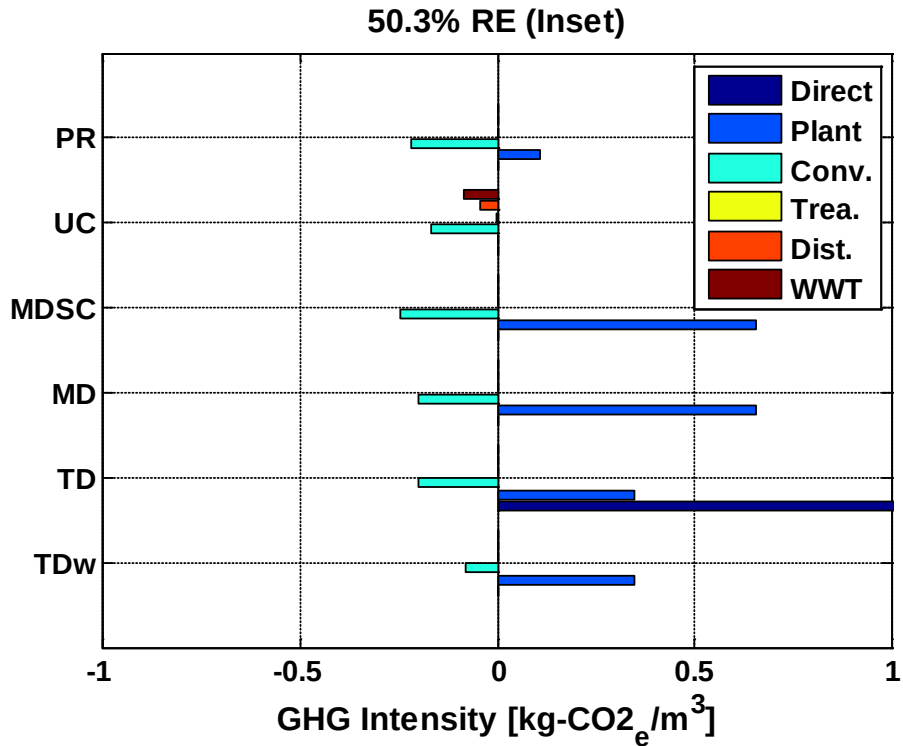


Figure 210 - Greenhouse Gas Intensity Breakdown for Different Individual Options at a 50.3% Grid Renewable Penetration Level

As the renewable penetration is increased, the incremental emissions for all components based on electric loads decreases in magnitude. The net incremental effect of implementing the individual options at different renewable penetration levels is summarized in Table 67:

Table 67 - Net Incremental GHG Intensity [kg-CO₂e/m³]

Option	10.7% RE	20.7% RE	50.3% RE
TDw	1.0017	0.6782	0.2710
TD	0.5494	0.3719	0.1486
MD	1.6767	1.1352	0.4536
MD (SC)	1.5055	1.0192	0.4073
UC	-1.1071	-0.7495	-0.2995
PR	-0.4018	-0.2720	-0.1087

These results emphasize the importance of considering systematic effects when evaluating the greenhouse gas impacts of water supply stabilization options. The net effect of these options is the metric that is important to consider, and should be used as a criterion for deciding how much of each options to use to stabilize reservoir levels on a greenhouse gas emissions basis. For these systematic effects to be realized in the real system, however, coordinated water supply management must be implemented. Regions implementing these options must communicate with the entities that manage the water supply system, such that energy is not wasted by conveying water to a region where it will not be needed.

6.2.1.3.3. Greenhouse Gas Impacts of Stabilizing Reservoir Levels

With an understanding of the net effect of individual options on greenhouse gas emissions, the greenhouse gas impacts of the individual and hybrid option cases that successfully stabilized surface reservoir levels determined from Section 5.2. can be discussed. The change in the greenhouse gas emissions from the no-option case as a percentage of the no-option case emissions for each of the successful portfolios is presented in Figure 211 for baseline conditions and in Figure 212 for climate change augment conditions.

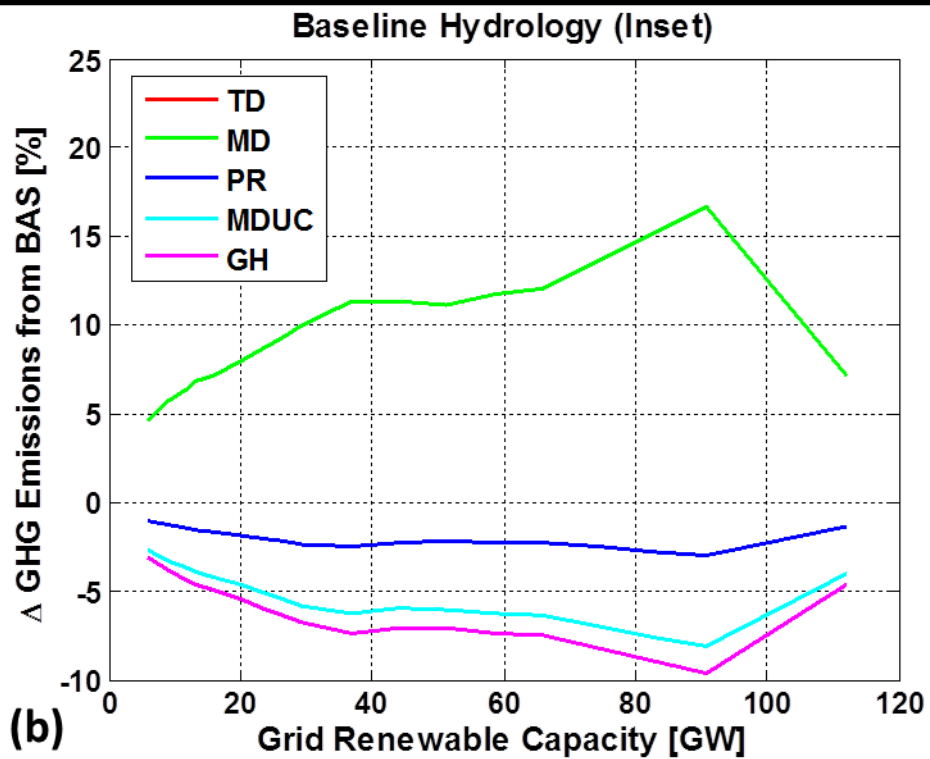
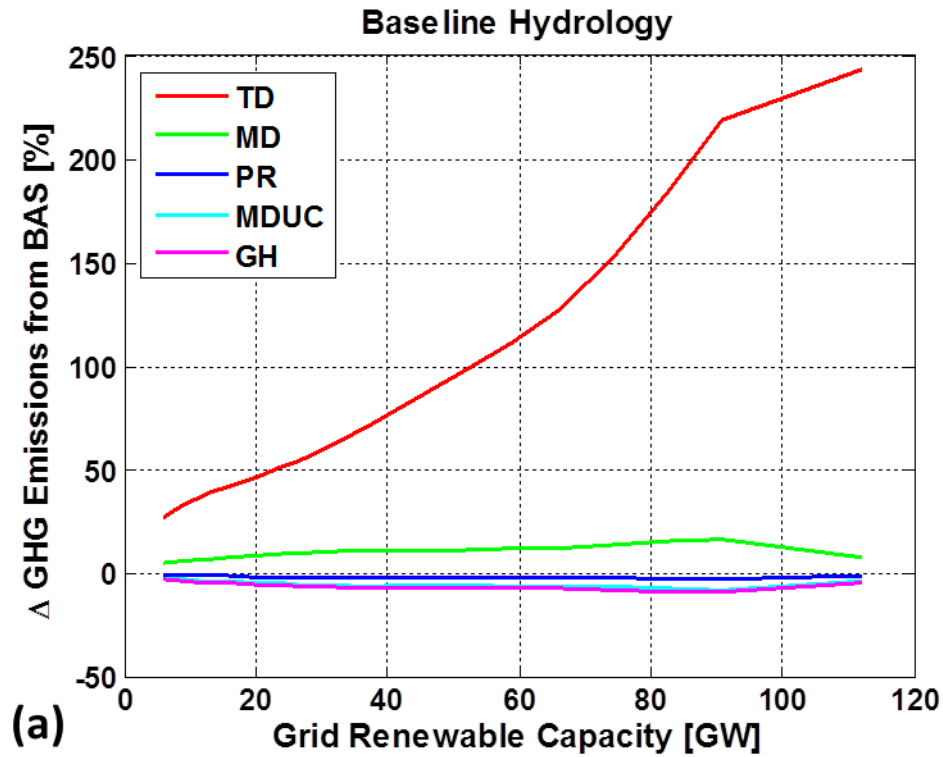


Figure 211 - Change in Greenhouse Gas Emissions from the No-Option Case under Baseline Conditions as a percentage of the No-Option Case value vs. Grid Renewable Capacity

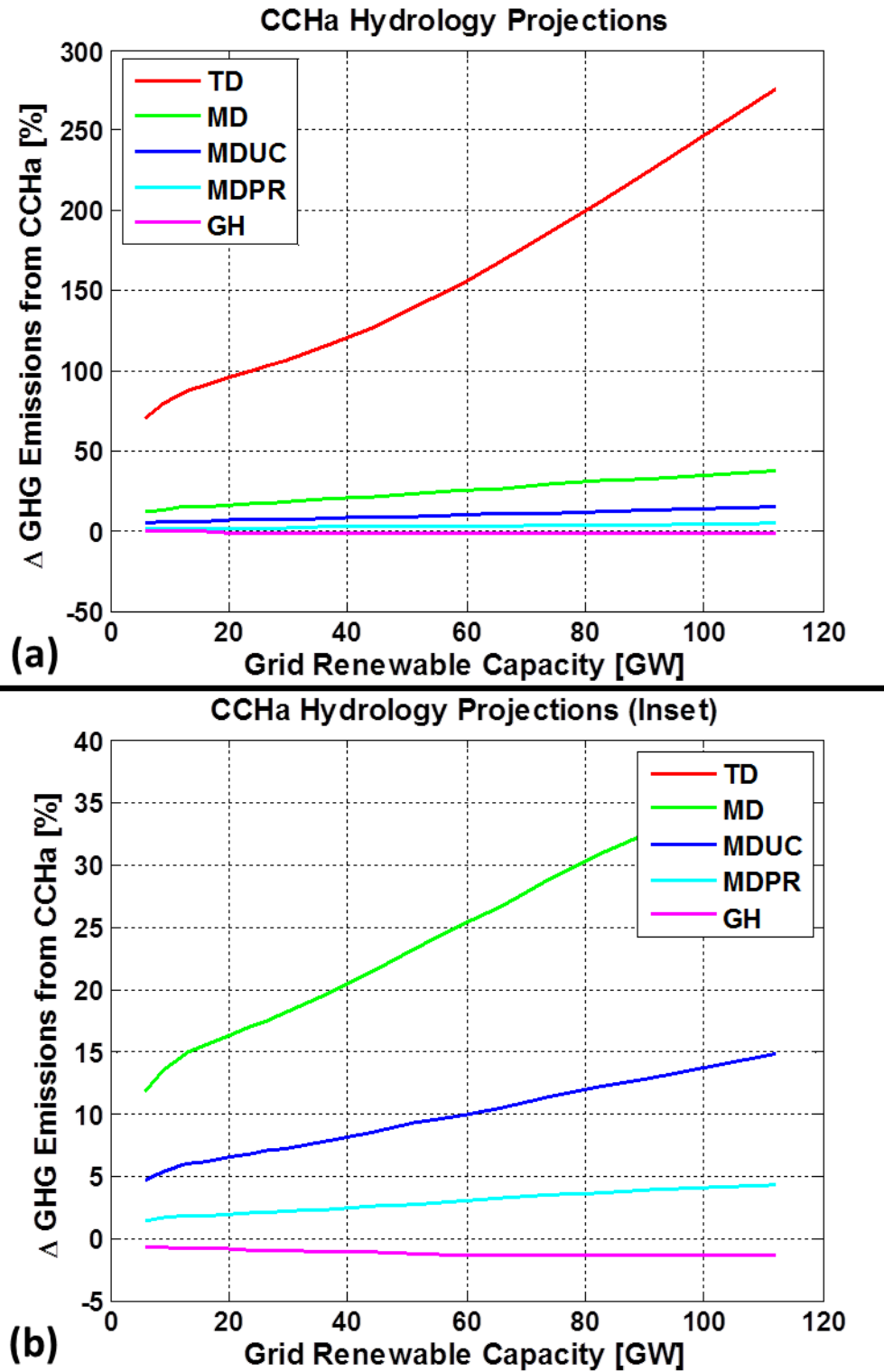


Figure 212 - Change in Greenhouse Gas Emissions from the No-Option Case under Climate Change Augment Conditions as a percentage of the No-Option Case value vs. Grid Renewable Capacity

Under baseline conditions, three of the successful water stabilization option portfolios (PR, MDUC, GH) have a near-neutral or beneficial impact on the greenhouse gas emissions of the system. Since many of these emissions are through the interaction with the electric grid, the benefits increase with increased renewable capacities on the grid. The exception occurs at very high renewable capacities, where mismatch between renewable generation and water stabilization option loads cause these loads to be met with natural gas instead of renewables. This reduces the benefit of these three cases compared to the base case, but increases the benefit of the MD case, since the latter is able to utilize otherwise-curtailed renewable generation.

The use of thermal desalination with natural gas, as expected, significantly increases GHG emissions compared to the base case. The high direct emissions of this option do not decrease with renewable capacity since they are not electric in nature.

The MD case shows increases in the change in GHG emissions as a percentage of the base case with renewable capacity, due to the additional load placed on the grid that must be met with additional natural-gas power plant generation. Note that this does not indicate that membrane desalination is increasing the absolute GHG emissions as more renewable capacity is being added. Recall that the base case emissions decrease with renewable capacity installation.

Therefore, this increase indicates that the emissions due to the membrane desalination load demand are not decreasing at the same rate as the rest of the bulk grid. This also is due to a lower coherence in the profiles of desalination loads and renewable generation, compared to that of the bulk grid load and renewable generation.

Under climate change augment conditions, all of the option portfolios that were successful at stabilizing water reservoir levels cause an increase in greenhouse gas emissions except for the

GH case. Recall that all of the cases except for the TD case require some amount of membrane desalination, which increases the electric load demand, since other measures are insufficient to stabilize reservoir levels alone under these conditions. Additionally, the scale of the required technologies is also much larger, imposing larger loads on the grid compared to the baseline case. Similar to the baseline case, thermal desalination demonstrates significantly increased GHG emissions compared to the base case.

All of these cases do not show the inverted behavior at high renewable capacities demonstrated in the baseline case results, since growth in the electric load demand does not allow large amounts of excess renewable generation to be present.

The GH case, which represents the water supply stabilization portfolio configured for the lowest possible greenhouse gases, is able to marginally reduce the greenhouse gas emissions compared to the no-option case under these conditions. This mix heavily uses urban water conservation, available water reuse, and uses only the minimum amount membrane desalination needed to stabilize the reservoir levels. This demonstrates that even with increases in demand and reductions in reservoir inflow, surface water reservoir levels can potentially be stabilized with little to no impact on greenhouse gas emissions, and emphasizes the importance of careful selection. Recall that when examining water goals alone in Section 5.2., urban water conservation had a slightly smaller incremental effect as water reuse due to its spatial distribution, and less overall potential. On the basis of energy goals, however, it is the best option and should be utilized as much as possible, with other options taking decreased priority.

6.2.1.3.4. Renewable Energy Utilization Impacts of Stabilizing Reservoir Levels

California, as well as other states and entities, have set targets for the utilization of renewable energy on the electric grid known as renewable portfolio standards (RPS). Many analyses have

focused on the deployment of renewable capacity to meet this target assuming load growth due to population only. This assumption is based on the composition of the electric load demand being relatively static in the future. However, many options for meeting the sustainability goals of other resource sectors such as have effects on the electric load. Depending how these options are deployed, their presence can change the composition and magnitude of the electric load in ways not currently taken into account in RPS analyses.

The water supply sector is one such resource sector, along with transportation. The effects of transportation options on the ability to meet RPS goals have been examined by Tarroja [343]. This analysis focuses on the effect of taking different pathways to secure surface reservoir levels on the ability to meet renewable portfolio standards in the region.

Figure 213 shows the grid renewable penetration as a function of installed renewable capacity, using the renewable mix specified in this study. The dotted line shows the current RPS goal in California [298], which targets a 33% renewable penetration by energy by the year 2020.

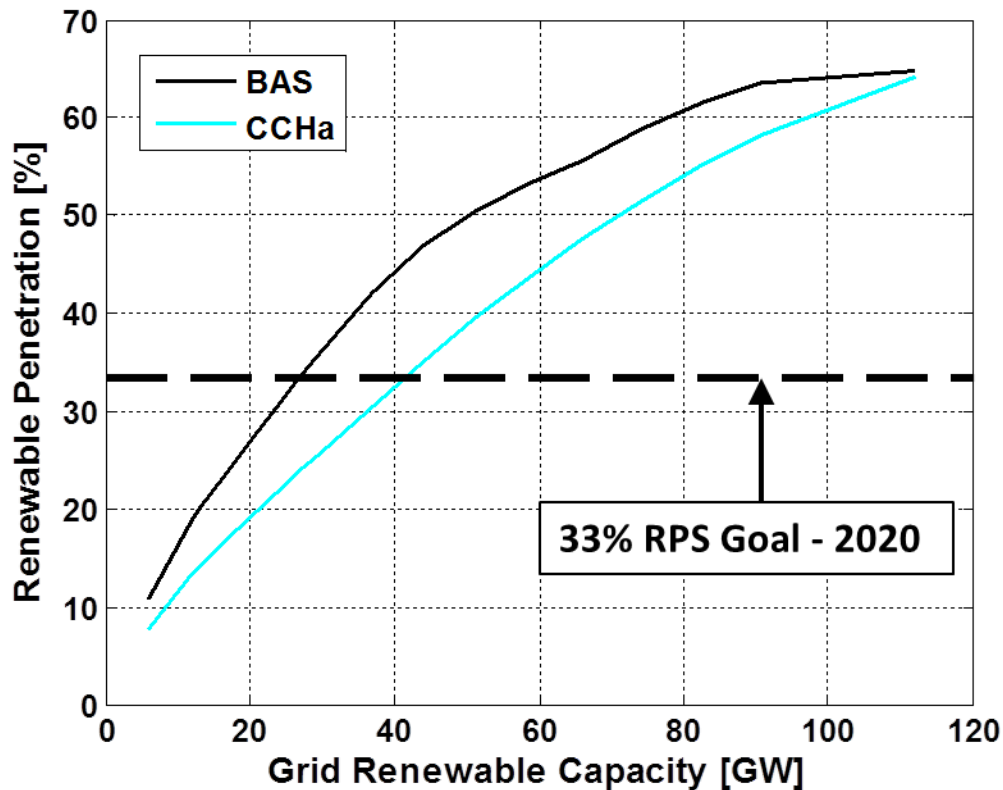


Figure 213 - No-Option Grid Renewable Penetration vs. Grid Renewable Capacity for Baseline and Climate Change Augment Conditions

Under baseline conditions, the renewable penetration initially increases linearly with installed capacity, however, it tailors off at high renewable capacities due to curtailment of excess renewable generation. This trend has been studied in detail by Tarroja [221] and Eichman [344].

Under climate change augment conditions, more installed renewable capacity is required to meet the same renewable penetration level. This primarily occurs due to the growth of the electric demand caused by population. Therefore, more renewable capacity is required to meet a given percentage of the load demand.

The effect of the successful water option portfolios on the grid renewable penetration level relative to the no-option case for baseline conditions is presented in Figure 214. Note that this is presented as a change from the no-option value vs. the no-option case value. For example, at a

10.7% no-option (base) renewable penetration, the GH case increases the renewable penetration by 2.4%, resulting in an actual renewable penetration of 13.1%.

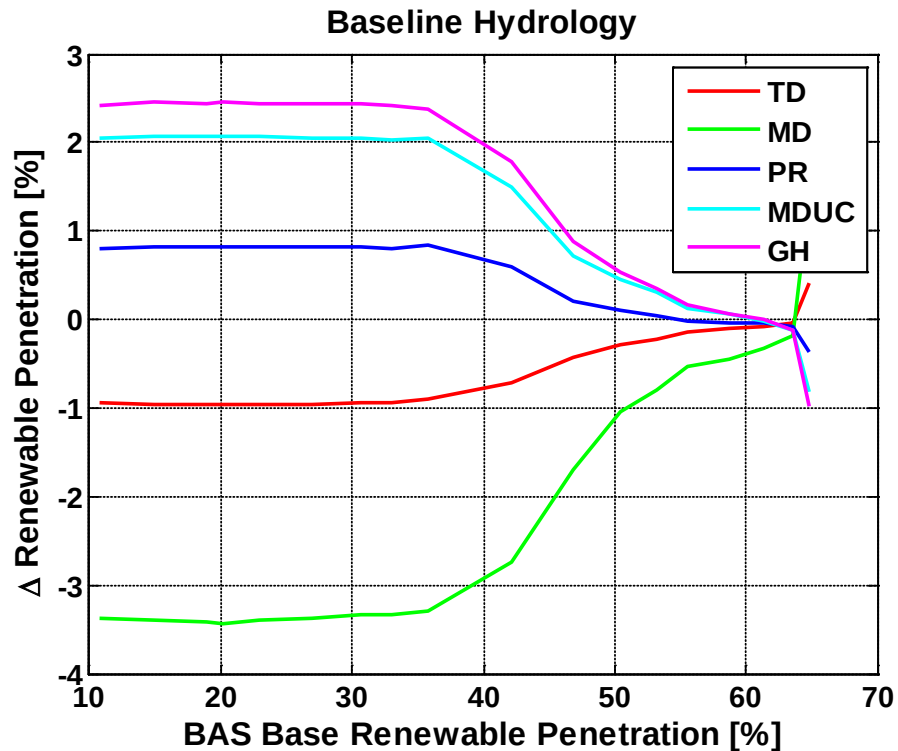


Figure 214 - Change in Renewable Penetration from No-Option Case vs. No-Option Renewable Penetration Level – Baseline Conditions

For most of the range of renewable capacities considered here, three of the portfolios (PR, MDUC, GH) tend to increase renewable energy utilization while the desalination-only portfolios tend to decrease it (TD, MD). This occurs due to the fact that the PR, MDUC, and GH portfolios tend to remove load from the electric grid, allowing a given renewable capacity to serve a larger fraction of the overall electric load. These cases increase the renewable penetration by up to 2.5%, 2.0%, and 0.9%, respectively. This indicates that using these portfolios to stabilize surface reservoir levels can aid in helping achieve renewable portfolio standard goals. The TD and MD cases, conversely, do the opposite by imposing electric load, reducing the renewable penetration

level by up to 1.0% and 3.3%, respectively, potentially providing difficulty in helping the state meet renewable portfolio standard goals. Membrane desalination has the largest negative effect, since it imposes the largest electric load on the grid.

At higher renewable capacities, the effect of these different paths is reduced and even reverses at the very high end of the range. This occurs since the load-adding technologies are able to use excess renewable generation that would otherwise be curtailed, increasing the overall energy fraction of the load served by renewables. Conversely, load-reducing technologies in this part of the range can remove electric load at times where it would have been served by high renewable generation, decreasing the overall renewable penetration.

It is important to note, however, that in the real-world system, water supply measures will not have the exclusive rights to use excess renewable generation. Other loads such as that due to electric vehicles, hydrogen electrolysis, or technologies such as energy storage all benefit from the use of excess renewable generation, however, how excess generation will be distributed between all of these loads will be an important, but open, question that is beyond the scope of this analysis. Therefore, the reversal in behavior between the portfolios should be viewed within context.

The effect of the successful water option portfolios on the grid renewable penetration level relative to the no-option case for climate change augment conditions is presented in Figure 215:

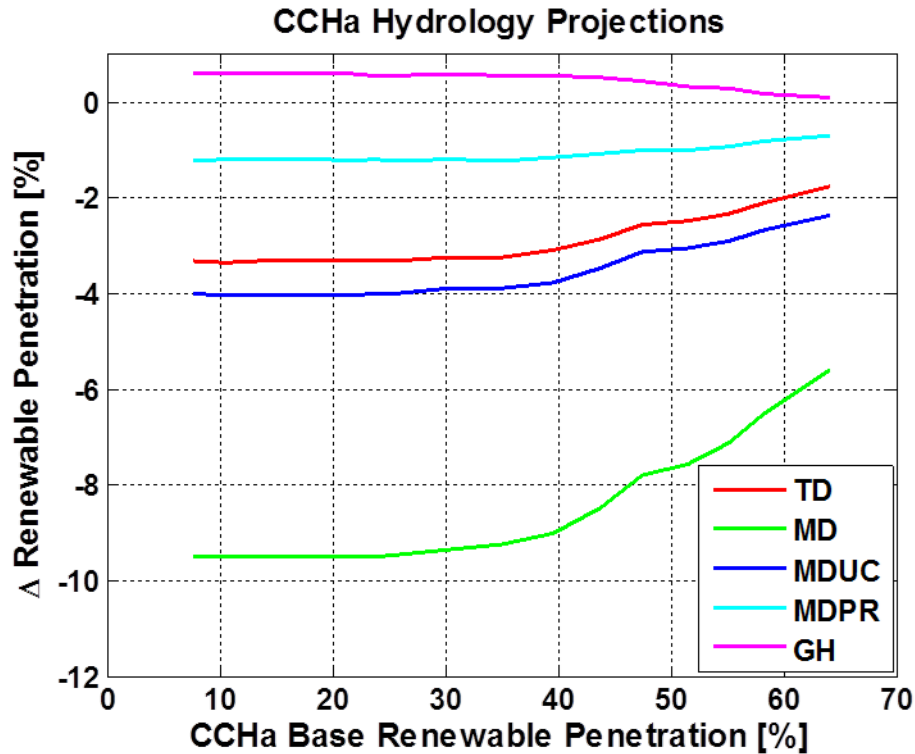


Figure 215 - Change in Renewable Penetration from No-Option Case vs. No-Option Renewable Penetration Level – Climate Change Augment Conditions

Due to the scale of the options required to stabilize water reservoir levels, most of the option portfolios add load to the electric grid, with the exception of the GH case. The MDPR, TD, MDUC, and MD cases reduce the renewable penetration by up to 1.2%, 3.3%, 4.0%, and 9.6%, respectively. At low base renewable penetration levels, stabilizing surface reservoir levels will hinder the ability of the electric grid to meet RPS goals to different extents, requiring even more renewable capacity to be installed. This is especially true of the membrane desalination only case, which will require large increases in renewable capacity to meet a given renewable penetration level.

The GH case, where water stabilizing options are chosen based on minimizing combined system greenhouse gas emissions, has a slightly beneficial impact on the ability of the system to meet RPS goals, but is mostly neutral.

Under these conditions, the decrease of the effect of installing the load-adding portfolios is also due to the use of otherwise curtailed renewable generation. Since the raw electric load demand is much larger under these conditions, however, excess renewable generation is not as prevalent.

6.2.1.4. Summary and Conclusions

6.2.1.4.1. Summary

The effects of implementing options to stabilize surface reservoir levels on greenhouse gas emissions and the ability to meet renewable energy utilization goals was conducted for the California water-electricity system, under baseline and climate change augment inflow conditions. The portfolio of options needed to stabilize the surface water reservoir levels under historical and climate change conditions was determined in Section 5.2. The implications of deploying these profiles for combined system greenhouse gas emissions and renewable utilization were determined by subjecting the electric grid to the effect of these profiles and that of the appropriate hydrologic condition.

6.2.1.4.2. Conclusions

The key conclusions of this study are as follows:

1. Greenhouse gas emissions increase due to reduced hydropower generation under climate change augmented conditions. Reduced reservoir inflow decreases the energy contribution of hydropower towards serving the load demand and its ability to provide grid reliability services. This must be compensated for by natural-gas power plants, which produce emissions. This effect is small, however, relative to emissions increases due to demand growth.

2. Emissions effects due to systematic impacts of implementing options must be taken into account. When emissions effects due to impacts on electric loads due to conveyance, treatment, distribution, and wastewater treatment are taken into account for each option, the greenhouse gas emissions intensity maybe very different compared to evaluating direct and process-based emissions alone.

3. For this system, the priority of available options from a greenhouse gas emissions perspective is as follows:

- Urban Water Conservation
- Water reuse
- Thermal Desalination w/Waste Heat
- Membrane Desalination
- Thermal Desalination w/Direct Natural Gas

Recall from Section 5.2, however, that the lowest emission options are limited in their ability to contribute towards stabilizing reservoir levels, necessitating the use of higher emission options.

4. Reservoir levels may be secured with beneficial or neutral effects on greenhouse gas emissions if the portfolio of water supply stabilizing options is chosen carefully. Under baseline conditions, it was shown that certain portfolios actually reduced greenhouse gas emissions compared to the no-option case. Under climate change augment conditions, a carefully selected portfolio of measures can stabilize reservoir levels with no net effect on greenhouse gas emissions.

5. Stabilizing surface reservoir levels can either be detrimental or beneficial for progress towards satisfying renewable portfolio standard goals, depending on portfolio composition. Under baseline conditions, successful portfolios changed the grid renewable penetration level by between -2.5% to +3.3%, while under climate change augment conditions, this range is altered to between -9.6 to +0.7%.

Overall, there are many criteria which must be considered when planning a strategy to meet both goals of stabilizing water supplies and reducing greenhouse gas emissions simultaneously. Certain options perform well on one criterion, but may not do so on another. Additionally, certain options are physically limited in their ability to contribute to satisfying either goal. Practical, implementation, and social challenges are also strong factors in influencing these strategies, and coordinated management of water supplies must be present to take advantage of identified synergistic interactions between the electricity and water supply sectors.

This study was aimed at providing some quantitative insight into how available options perform based on different criteria. While many criteria have not been evaluated or are not quantifiable, the results of both Section 5.2 and this section provide some direction for policy planners to develop strategies for option deployment to satisfy sustainability goals. Evaluation of these options on the basis of additional criteria and further exploration of the implications of these results are subjects for future work.

Chapter 7: Holistic Evaluation of Sustainability Options in the Combined Trisector System

This section presents results for the performance of different sustainability-oriented option sets in the context of the combined system of all three resource sectors: electricity, light-duty transportation, and water supply.

7.1. Electricity-Transportation-Water Supply System

7.1.1. Approach

To gain insight for advising the deployment of sustainability-oriented technology and management options in electricity, light-duty transportation, and water supply sectors to meet holistic sustainability goals for the combined system, common targets for the extent to which these goals are met are designated. This provides a common basis against which to evaluate the advantages and disadvantages of different technology and management option deployment cases.

7.1.1.1. Sustainability Goals for All Cases

For this particular analysis, all cases will be required to meet the following sustainability goals:

- **California's 2050 greenhouse gas (GHG) emissions target will be met, as specified by Assembly Bill 32 [345].** The total annual greenhouse gas emissions (in CO₂e) of the combined electricity, transportation, and water supply system must be equal to 20% of system emissions in the year 1990.
- **The surface water supply must be secured under the impacts of water-related climate change effects.** This is measured by the net reservoir fill level of California's major surface reservoir levels, which must be equal to or greater than zero over the time period for the surface reservoir levels to be secured.

All cases will represent the status of the combined electricity, transportation, and water supply system in California in the year 2050, where these sustainability goals are met using different sets of technology and management options.

Other sustainability goals of consideration, such as securing the primary energy supply and improving air quality, are not measured directly. These goals, however, may be met as a result of meeting the aforementioned two goals. Deploying low-carbon energy resources generally tends to reduce air pollutant emissions since most of these technologies do not burn hydrocarbon fuel and have no operating emissions of any kind. The deployment of renewable resources, which may need to be heavily relied upon to meet the aforementioned goals, contribute towards securing the primary energy supply by sourcing generation from in-state areas with minimal reliance on fuel supply chains for natural gas and coal.

7.1.1.2. Determining the Sustainability Goal Targets

The specific, quantitative targets that must be met by all cases, representing satisfaction of the aforementioned sustainability goals, are determined as follows.

7.1.1.2.1. California's 2050 Greenhouse Gas Emissions Target

The 2050 GHG emissions target is determined by use of the California Air Resources Board (CARB) GHG inventory [74]. This inventory specifies in-operation electricity and light-duty transportation sector GHG emissions for the years 1990 to 2010 associated with meeting the state's electricity and transportation demand, regardless of whether the source emits GHGs within the state borders. The UCI-STREET model, however, includes in-operation emissions as well as certain upstream emissions components such as mining and transport of fuels for electricity generation and the transport and refining of petroleum fuel, as described in Section 4.1. To designate a target for the cases simulated in the model to satisfy, the year 1990 GHG

emissions basis specified by the CARB inventory must be adjusted to account for these components. Additionally, the datasets for the UCI-STREET model are for a base year of 2005, and the designated target must also take this into account.

Upstream emissions are specified in the CARB inventory, but are not delineated by component. Therefore, to set a consistent target, the ratio of in-operation emissions to total emissions for the base year of the UCI-STREET model was calculated by simulation. The in-operation components for the model are within 2% of the CARB inventory figures, as described in Section 4.1.

For the year 2005, this ratio was calculated to be 95.98%. The calculated ratio for the year 2005 was maintained and applied to the in-operation emissions figures for the year 1990, yielding an annual GHG emissions level of 234.343 MMT CO₂e. The year 2050 annual GHG emissions target as specified by AB32 is 80% below this level: **46.829 MMT CO₂e**. This is summarized in

Table 68 - Year 1990 In-Operation Emissions for the Electricity and Light-Duty Transportation Sectors in California

<u>Component</u>	<u>Year 1990 GHG Emissions (MMT CO₂e)</u>
Year 1990 - Electricity Sector	115.843
Year 1990 - Light Duty Automobiles	63.746
Year 1990 - Light Duty Trucks	44.754
Year 1990 Total In-Operation	224.343
Scaled to Include UCI-STREET Upstream Components	234.147
Year 2050 Cases Target	46.829

While direct emissions from the water supply sector (emissions not associated with electric loads) are not specified directly, the measures considered in this study that will be deployed to secure the water supply in the future produce emissions exclusively through imposing electric

loads on the grid. Additionally, much of the energy for conveyance and distribution of water is also sourced from the electric grid. Therefore, the additional emissions due to water supply measures will manifest as electric grid emissions. The non-electricity related water supply emissions are assumed to be constant.

7.1.1.2.2. Securing the Surface Water Supply

Similar to the analysis in Section 5.2., the criteria for the surface water supply being secure is that the net reservoir fill level change over a ten-year period is equal to or greater than zero. This indicates that regardless of changes in supply and demand, the reservoirs are able to recover to their original levels. This also has the assumption that the groundwater demand for the state does not change, similar to the previous analysis.

7.1.1.3. Case Development

Many different control parameters can be used to develop cases for composing technology and management portfolios to satisfy sustainability goals. These include but are not limited to:

- Economic Impact: Various cost parameters can be varied to purposefully optimize the portfolio based on cost as the sole driving factor.
- Time to Deployment: The portfolio can be optimized to meet a given set of sustainability goals in the least time possible, considering permitting and construction times.
- Energy Intensity: The portfolio can be optimized to use the lowest amount of energy possible in meeting a given sustainability goal while providing societal services.

While many of these technical and economic criteria are good bases on which to determine a case for analysis, these criteria do not necessarily represent the criteria that will be used to actually deploy sustainability-oriented measures to satisfy sustainability goals. Rather, deployment of any given set of technology and management options is likely to depend strongly

on social attitudes towards how each individual sector should evolve, among the public and among societal leaders. While social attitudes are influenced by individual technical and economic factors, they do not necessarily follow the trend of any one driving factor, and are often strongly influenced by non-quantitative factors. Care must be taken when interpreting the results of using ‘optimized’ portfolios based on prioritizing one single factor.

Therefore, to construct the cases for analysis in this study, the primary factor for determining the technology and management portfolios is the degree of consumer involvement in deploying and managing options to meet sustainability goals. Specifically, two extreme paradigms are considered for each resource sector: Visible and Transparent.

- A **Visible** paradigm indicates that consumers are highly involved with deploying and managing sustainability oriented options on a day-to-day basis. In this paradigm, the technology and management options that are deployed are ones that are highly visible to the general public and on the local scale. An example of a visible option in the electricity sector would be relying on rooftop solar photovoltaic (PV), which consumers would have to install on their buildings and the local community would need to manage. Obtaining benefits from these options depend on consumers being comfortable with adjusting their routine behavior to accommodate their behavior.
- A **Transparent** paradigm indicates that consumers are not involved with deploying and managing sustainability oriented options on a day-to-day basis. In this paradigm, the technology and management options that are deployed are ones that are mostly transparent to the general public. An example of a transparent option in the electricity

sector would be centralized, utility scale solar thermal installations, which are located away from population centers and provide power to the grid without regular consumer involvement. Obtaining benefits from these options do not depend strongly on consumers adjusting their routine behavior.

Options in each resource sector are treated separately in this regard, although their performance will be evaluated holistically. Consumers may be comfortable with being involved in managing electricity generation, but not water supply and light duty transportation fueling, for example. The details of what technologies and options are deployed in each sector for each paradigm will be described in the following section.

7.1.1.4 Technology and Management Option Portfolio Descriptions

This section will describe the specifics of how the technology and management option portfolios were composed for each of the paradigms in each of the resource sectors.

7.1.1.4.1 Electricity Sector

7.1.1.4.1.1. Common Options and Case Settings

The following case settings and technology/management options are common in both Visible and Transparent paradigms in the electricity sector.

- **The stationary load demand has been increased with population.** Compared to the base year of 2005, the population in 2040 has increased by about 40% [192]. Therefore, the base grid load demand is increased by the same amount.
- **Coal power generation has been completely eliminated by 2050.** This is an extrapolation on current trends aimed at reducing coal power generation in California, where the contribution of coal power to California has been cut in half between 2005 and 2011 [299].

- **Nuclear power generation is unchanged from year 2013 levels at 2.24 GW.** This takes into account the recent shutdown of the San Onofre Nuclear Power Plant, leaving the Diablo Canyon Power Plant as the only operating nuclear power plant in the state [193].
- **Small hydropower capacity is unchanged from current levels at 1.3 GW [134].** Small hydropower has not been projected by the CPUC to be a significant contributor to the renewable portfolio due to environmental constraints [65].
- **Additional biopower utilization has been set to its currently characterized maximum potential of 34,624 GWh per year [290, 346].** It is assumed that biopower utilization is maximized, regardless of paradigm. Biopower fuel is used to displace natural gas fuel in peaking and load following power plants, and is assumed to be injected into the natural gas pipeline.

7.1.1.4.1.2. Visible Electricity Paradigm

The following case settings and technology/management options comprise a Visible paradigm for the evolution of the electricity sector. This paradigm represents an electricity infrastructure that is heavily dependent on energy resources in or near population centers, structured as microgrids managing these resources to meet the electric load in each particular community.

- **Primary reliance on fixed rooftop solar photovoltaic (PV) power.** In California, the primary low-carbon resource that can scale up to sufficient levels to meet the increased electric load demand that can be installed at the local scale is solar PV. These units would be installed on commercial, industrial, and residential buildings with their variability managed by local communities. These installations will take the form of fixed rooftop units, since ground-level land area is generally unavailable in populated areas and rooftops are generally not large enough to fit utility-scale tracking systems. The capacity

of solar PV required is tuned in conjunction with others to meet the aforementioned greenhouse gas goal.

- **No installations of utility-scale solar PV plants.** All of the solar PV installations are on the local scale.

- **Renewable capacities of non-solar PV types are limited at the 33% RPS level.**

Development of these capacities is assumed to continue to meet the 33% RPS, after which solar PV is primarily relied upon. This includes geothermal, regional wind, and solar thermal as follows:

- **Geothermal:** 1.64 GW additional above 2009 levels [289]
 - **Regional Wind:** 10.9 GW additional above 2009 levels [289]
 - **Solar Thermal:** 6.35 GW above additional above 2009 levels [289]
- **Energy Storage completely consists of Flow Batteries.** For load shifting applications, flow batteries are the primary type which can exhibit high energy and power applications, since energy and power capabilities of these units can be sized separately from each other. These units can also be installed at the community or building scale, fitting the visible paradigm. The capacity of energy storage required is a tuned parameter.
- **The balancing generation fleet consists of microturbines.** The power generation fleet that balances the load demand and provides grid reliability services is assumed to consist of small gas turbine power plants, cited at buildings or within the community. These units have a fast response capability and are assumed to have a design point efficiency of about 30.4%, which is correspondent with current peaking generation units [144]. This is also consistent with current microturbine technology [347].

7.1.1.4.1.3. Transparent Electricity Paradigm

The following case settings and technology/management options comprise a Transparent paradigm for the evolution of the electricity sector. This paradigm represents a heavy reliance on centralized installations for low-carbon and balancing generation, sited away from population centers and managed mostly by the balancing authority and utility. This is more similar to the historical paradigm of the electricity sector.

- **Geothermal power is utilized to its maximum potential of 4.0 GW additional [133].** Geothermal resource areas are out-of-sight and use mostly conventional technologies, and are therefore utilized heavily.
- **Regional wind power is utilized to its maximum high capacity factor potential of 30.39 GW additional [123, 221].** Wind power in California is mostly concentrated in the southeastern mountains bordering the state deserts, away from populated areas, and is utilized heavily.
- **Solar power capacity is split between 1-axis tracking solar PV and solar thermal trough power plants.** Since the resource potential of other low-carbon generation is limited relative to the scale required to meet the increased electric load demand, solar power must be relied upon heavily to meet the greenhouse gas target. In this paradigm, this is to consist of 50% utility scale, tracking PV and 50% solar thermal trough installations, sited in the high radiation areas of the state's southeastern deserts. The total solar power capacity is a tuned parameter.
- **Energy storage consists of a mix of pumped hydropower and battery storage.** The energy storage power capacity mix is assumed to consist of 60% flow batteries and 40% pumped hydropower storage. Since pumped hydropower storage is limited in potential,

batteries still compose the majority of the mix. The total capacity of energy storage is a tuned parameter.

- **The balancing generation fleet consists of large-scale, centralized combined cycle power plants.** Large central power plants are typically sited away from load centers, fitting with the transparent paradigm. The large size of these units allows energy recuperation and advanced turbine technologies to be installed. This study designates a design point efficiency of about 61%, which corresponds to that of currently available combined cycle power plant units [348].

7.1.1.4.2. Light Duty Transportation Sector

7.1.1.4.2.1. Common Options and Case Settings

The following case settings and technology/management options are common in both Visible and Transparent paradigms in the light duty transportation sector.

- **Alternative fuel vehicles compose 87% of the light-duty transportation vehicle fleet.** Projections by CARB estimate that the alternative vehicles will need to compose 87% of the light duty-transportation fleet in 2050. While the CARB projections estimate some mix of battery electric and fuel cell vehicles, this analysis assumes that the entire 87% is composed of either BEVs or FCVs to represent the different paradigms.
- **The fleet-wide average fuel economy of gasoline vehicles has reached 54.5 miles per gallon.** This is representative based on current Corporate Average Fuel Economy (CAFE) goals for the year 2025 [28]. Due to the manner that corporate average fuel economy is measured for meeting the CAFE standard, a 54.5 mpg CAFE figure does not necessarily indicate an average of 54.5 mpg in real-world driving. For this analysis, however, we

assume that 25 years after the standard in 2050, this figure is actually achieved for the typical gasoline vehicle.

- **The vehicle-miles-traveled (VMT) demand has increased with population.** Similar to the stationary load demand, the amount of miles traveled by light duty vehicles is assumed to scale with population.

7.1.1.4.2.2. Visible Transportation Paradigm

The following case settings and technology/management options comprise a Visible paradigm for the evolution of the light-duty transportation sector.

- **Primary reliance on Battery Electric Vehicles (BEVs).** Battery electric vehicles are the alternative vehicle technology of choice for the Visible paradigm. These vehicles are typically charged at residences, and charging is managed within the constraint of allowing the consumer to have sufficient charge to meet their travel demands for the next day. Consumers are highly involved with managing this technology by setting constraints on the charging load (and therefore its flexibility), installing this infrastructure within their homes and workplaces, and allowing the grid operator to control the charging of their batteries.
- **BEV infrastructure configuration and capabilities.** The settings for the BEV chargers and the vehicles themselves are the same as those used for the analysis in Section 6.1.2., with some exceptions. These settings are summarized as follows. Justifications for these choices are presented in the description of the BEV/FCV spanning analysis. Differences from the previous settings are noted and explained where necessary.
 - o Typical Range: **200 miles**
 - o Average Charging Power: **6.6 kW** (Level 2)

- o On-Road Vehicle Fuel Economy: **0.40 kWh/mi.** BEVs are relatively efficient from a tank-to-wheel basis, since only one step is needed to convert stored electric energy to mechanical energy by use of an electric motor, which already exhibits efficiencies of 85% or higher. Therefore, we do not expect the drivetrain efficiency for BEVs is not expected to change significantly from current levels, as explained in Section 6.1.2.
- o Charging Dispatch: **Optimal.** Consumers submit their travel schedules into the forecast for the BEV charging load, and this load is dispatched to provide benefits to the electric grid within those constraints. This also assumes that the day-ahead forecast for the BEV charging load is completely correct, indicating that consumers adhere to their schedules.
- o Charging Locations: **Home and Workplace.** This setting is different than that in the BEV/FCV spanning analysis. Since this case represents the light-duty infrastructure in the far future, it is assumed that charging stations are available at workplaces in addition to residences. Charging capability is still assumed to be Level 2.

7.1.1.4.2.3. Transparent Transportation Paradigm

The following case settings and technology management options comprise a Visible paradigm for the evolution of the light-duty transportation sector.

- **Primary reliance on Hydrogen Fuel Cell Vehicles (FCVs).** Hydrogen fuel cell vehicles are the alternative vehicle of choice for the Transparent paradigm. These vehicles are typically fueled in the same manner as gasoline vehicles, and as of the current date, have longer range capabilities compared to BEVs. This allows consumers to schedule their

travel patterns freely, since production of hydrogen is decoupled on short timescales from hydrogen fueling.

- **FCV infrastructure configuration and capabilities.** The configuration for the FCV infrastructure and the vehicles themselves are also the same as those used for the analysis in Section 6.1.2., with some exceptions. This configuration is summarized as follows. Again, justifications for these choices are presented in the description of the BEV/FCV spanning analysis and differences from the previous settings are noted and explained where necessary.
 - o Production Mix: **90% Electrolysis / 10% Steam Methane Reformation.** Since this analysis is not a spanning analysis, the production mix is fixed. Steam methane reformation (SMR) has greenhouse gas emissions, which, while higher than other hydrogen production methods, are still significant in the context of meeting a strict emissions cap. These emissions do not decrease with the installation of renewable resources. Therefore, steam methane reformation was minimized. Some capacity remains, however, since SMR will likely have been the dominant mode of hydrogen production during the earlier stages of FCV deployment.
 - o Delivery Method: **100% by Pipeline Network**
 - o Distribution Method: **350 bar gaseous hydrogen.**
 - o On-Road Vehicle Fuel Economy: **70 mi/kg.** This is higher than the fuel economy of the fuel cell vehicles used in the BEV/FCV spanning analysis, which used 54 mi/kg. In contrast to BEVs, FCVs have additional room for drivetrain improvement due to increases in the efficiency of the proton exchange fuel cell

itself and its power density, which can reduce vehicle weight. Therefore, a slight improvement over current levels is used.

- o Aggregate Statewide Hydrogen Storage: 7% of annual demand. This is a parallel of the configuration of the natural gas infrastructure.
- o Electrolyzer dispatch: Smooth net electric load demand profile. Electrolyzer plants submit their schedules to the grid operator, and can be dispatched as needed within the constraint of meeting the hydrogen demand.

7.1.1.4.3. Water Supply Sector

7.1.1.4.3.1. Common Options and Case Settings

The following case settings and technology/management options are common in both Visible and Transparent paradigms in the water supply sector.

- **The bulk water demand change from current levels is consistent between both paradigms.** For both Visible and Transparent paradigms, the change in water demand is based on the “Current Trends” projection for the average annual water demand change between the 1998-2005 and 2040-2050 by the California Department of Water Resources (CA DWR) [48]. This demand change is associated with extrapolating current trends in demand, taking into account population growth and climate change effects.
- **In 2050, water-related climate change effects are assumed to take place.** These effects are modeled under the IPCC High Emissions Scenario (A2), using data from the CalAdapt database as described in Section 5.2. This assumes high greenhouse gas emissions in the rest of the world, and is used as a worst-case scenario for the impact of climate change.

- **Thermal Desalination with Direct Natural Gas is not considered.** From the results of the water reservoir analysis in Section 5.2., thermal desalination with direct natural gas was shown to exhibit very high greenhouse gas intensities. Additionally, since these emissions are direct from the thermal desalination plant, reducing the greenhouse gas intensity of the electric grid does not reduce them. Therefore, thermal desalination is only considered when using waste heat potential.

7.1.1.4.3.2. Visible Water Supply Paradigm

The following case settings and technology/management options comprise a Visible paradigm for the evolution of the water supply sector. This paradigm focuses heavily on reducing demand and efficient use of water. The following measures were deployed in order of priority, limited by the potential utilization of the measure. The specifics of the modeling of these measures were presented in Section 5.2.

- **Urban Water Conservation is the first priority.** Urban water conservation involves installing low-flow appliances, fixing leaks, and reducing inefficiencies. Many of these measures rely on consumer involvement to install the requisite hardware and alter their behavior to increase water use efficiency. From the results of the water-reservoir analysis presented earlier, this measure also imposes a net negative electric load onto the electric grid due to displacement of energy water conveyance. The full potential utilization is available.
- **Water Reuse is the second priority.** When urban water conservation is not sufficient to stabilize the surface water reservoir levels, purification and reuse of wastewater is used. This involves the purification of treated wastewater and injection into local reservoirs to be suitable for use as source water. While these processes take place in centralized plants,

these plants are typically sited within population centers to reduce the pumping requirements for conveying wastewater, making it therefore visible to consumers.

Additionally, consumers would have to develop the attitude of being comfortable with using water that was previously contaminated and trust the efficacy and management of the purification systems. In certain areas of the state, this measure still faces significant public resistance due to the ‘toilet-to-tap’ labeling. The full potential utilization is available.

- **Thermal Desalination with Waste Heat is the third priority.** When the previous two measures are insufficient to stabilize the surface water reservoir levels, thermal desalination with waste heat is used. This measure focuses on new supply, and has lower public visibility compared to the previous measures. Many of the coastal power plants which will provide the waste heat for these desalination plants, however, are sited near population centers. Therefore, the desalination plants will also have to be sited in close proximity, affecting the coastal environment near population centers. The full potential utilization is available.
- **Membrane Desalination is the last priority.** All three of the previous measures have hard technical limits on how much each can be scaled up. Therefore, when their combined contribution is insufficient to secure the water reservoir levels, membrane desalination is used to fill the difference.

7.1.1.4.3.3. Transparent Water Supply Paradigm

The following case settings and technology/management options comprise a Transparent paradigm for the evolution of the water supply sector. This paradigm focuses heavily on

procuring new supply. Again, the specifics of the modeling of these measures were presented in Section 5.2.

- **Urban Water Conservation is used, but limited in potential.** Urban water conservation takes place in this paradigm only due to fixing leaks and system inefficiencies. The portion associated with widespread installation of low-flow appliances and behavioral changes are not available. Potential utilization of this measure is limited to 25%.
- **Membrane Desalination dominates the additional supply mix.** Membrane desalination plants do not have the same siting restrictions as that of thermal desalination plants using waste heat. Therefore, these plants can technically be sited at any point along the coast, away from major population centers and consumer visibility.

7.1.1.5. Cases for Analysis and Approach

7.1.1.5.1. Development of Cases for Analysis

By choosing different paradigms for technology / management option deployment for each of the individual resource sectors, combined cases for the configuration of the entire system are developed. The cases are presented in Table 69. All of these cases represent the year 2050.

Table 69 - Year 2050 Cases for Analysis

<u>Electricity Sector Paradigm</u>	<u>Light Duty Transportation Sector Paradigm</u>	<u>Water Supply Sector Paradigm</u>	<u>Case Designation</u>
Transparent	Transparent	Transparent	TTT
Transparent	Transparent	Visible	TTV
Transparent	Visible	Transparent	TVT
Transparent	Visible	Visible	TVV
Visible	Transparent	Transparent	VTT
Visible	Transparent	Visible	VTV
Visible	Visible	Transparent	VVT
Visible	Visible	Visible	VVV

This approach is taken since it can help identify in which sectors consumer involvement will be beneficial to meeting holistic sustainability goals, and conversely, which sectors should be left managed by central authorities based on technical and economic criteria. This can help educate the public about what their optimal role is in helping to meet sustainability goals.

7.1.1.5.2. Parameter Tuning for the 2050 Cases

Since there are significant feedbacks between the different sectors, control parameters must be varied simultaneously. For example, increasing the capacity of solar thermal power plants increases water consumption, which increases the required capacity of water stabilization to meet the reservoir fill target, which can increase the electric load and therefore increase the capacity of solar thermal power required.

This analysis has three primary control parameters for each of the aforementioned cases:

- Total renewable power capacity.
 - In these cases, this refers to total solar power capacity since the capacities of the other renewable types are fixed in each different electricity sector paradigm.
- Energy storage capacity
- Water supply stabilization measure capacity

These parameters are tuned to ensure that each case meets the sustainability goals presented previously. A flow diagram of the tuning process is presented in Figure 216:

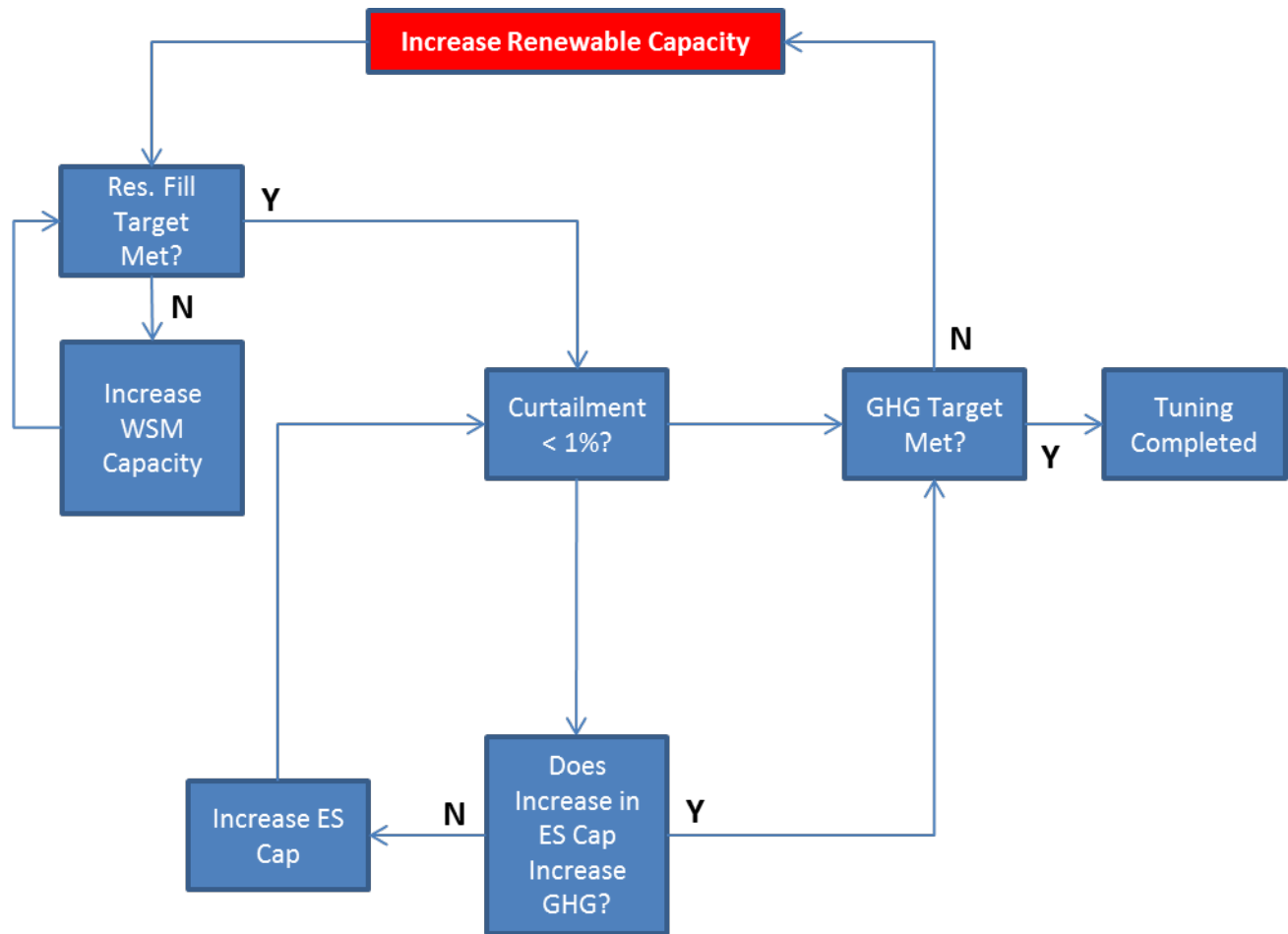


Figure 216 - Tuning of Control Parameters for each 2050 case. ES: Energy Storage, GHG: Greenhouse Gas, WSM: Water Supply Measure

A short summary of the tuning process is as follows:

- First, a very low guess for renewable capacity, water supply stabilization measure capacity, and energy storage capacity is initialized.
- An increase in the renewable capacity is instituted. This influences the water demand and therefore the reservoir fill level, as well as the percentage of renewable generation that is curtailed.

- The net reservoir fill level is checked. If the target is not met, water stabilization measure capacities are increased in order of priority for the designated water supply sector paradigm until the net reservoir fill level target is met.
- Next, the fraction of total renewable generation that is curtailed is checked.
 - If this fraction is less than 1%, the GHG emissions are checked.
 - If the GHG emissions target is met, the tuning is completed.
 - If the GHG emissions target is not met, renewable capacity is increased and the process repeats.
 - If this fraction is greater than 1, the GHG sensitivity to energy storage capacity is checked.
 - If increasing the energy storage capacity does not increase GHG emissions, the energy storage capacity is increased and the curtailment figure is checked again.
 - If increasing the energy storage capacity does increase GHG emissions, this indicates that curtailment cannot be reduced further without impeding progress towards meeting the sustainability goal. This can occur due to a number of factors such as the energy storage penalty and the effects on the dispatch of carbon-emitting balancing power plants. In this case, the GHG emissions are checked.
 - If the GHG target is met, then the energy storage capacity for this case is optimal.

- If the GHG target is not met, then GHG emissions are minimized for this given renewable capacity level. The renewable capacity is increased and the process repeats.

Overall, this process yields a renewable capacity and water supply stabilization measure mix that meets the sustainability goals, with an energy storage capacity that is optimized for the given installed renewable capacity.

7.1.1.5.3. Water-Electricity Iteration Loop

With this combined system approach, a symbiotic feedback exists between the electricity and water supply sectors. Altering the behavior of the electric power generation fleet changes the water consumption of the combined system. Changing the water consumption, in turn, changes the electric energy consumption of the system due to changes in the amount of energy associated with conveying water. This influences the magnitude and profile of the electric load, altering the behavior of the electric power generation fleet and creating a cycle. This is especially pronounced since balancing power plants are carbon emitting.

To ensure that this feedback converges such that the water consumption anomaly due to the grid and the energy anomaly associated with it are consistent, a guess-and-check iteration loop was placed around the entire model, as presented in Figure 217:

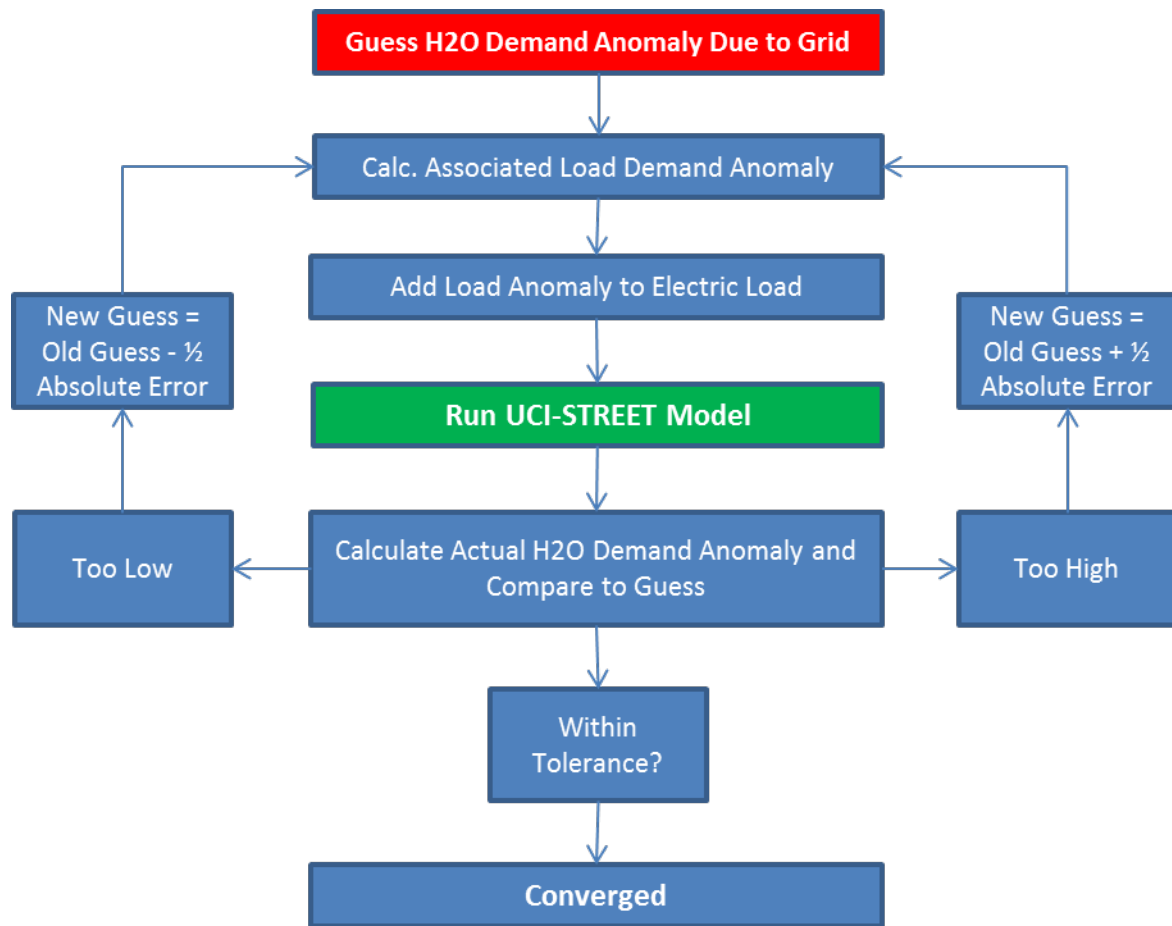


Figure 217 - Water-Electricity Iteration Loop

The water demand anomaly is the change in the water demand from the base demand for the given time period due to alterations in the behavior and composition of the electric power generation fleet on the electric grid. In the 2050 cases, it is the demand change from the 2040-2050 annual base demand. The water demand (consumption and withdrawal) for different power plant types was sourced from NREL [51], with the values used in this analysis specified in Table 70:

Table 70 - Water Demand for Different Electric Power Generation Technologies

Technology	Incremental Water Demand [gal/MWh]
Solar PV	26
Geothermal	1796
Wind	0
Nuclear	1101
Natural Gas Combined Cycle	253
Solar Thermal Trough	865
Solar Thermal Tower	786
Coal	1005

The total water demand is then calculated by weighting these factors by the total generation from each power plant type, and the difference from the base demand is determined as the anomaly.

The factors for the energy associated with water conveyance were presented in Section 6.2.

7.1.2. Results

7.1.2.1. Required Renewable Capacity

The renewable capacity required to achieve the targeted greenhouse gas reduction goal for each of the eight cases is presented in Figure 218, each with its corresponding resource breakdown.

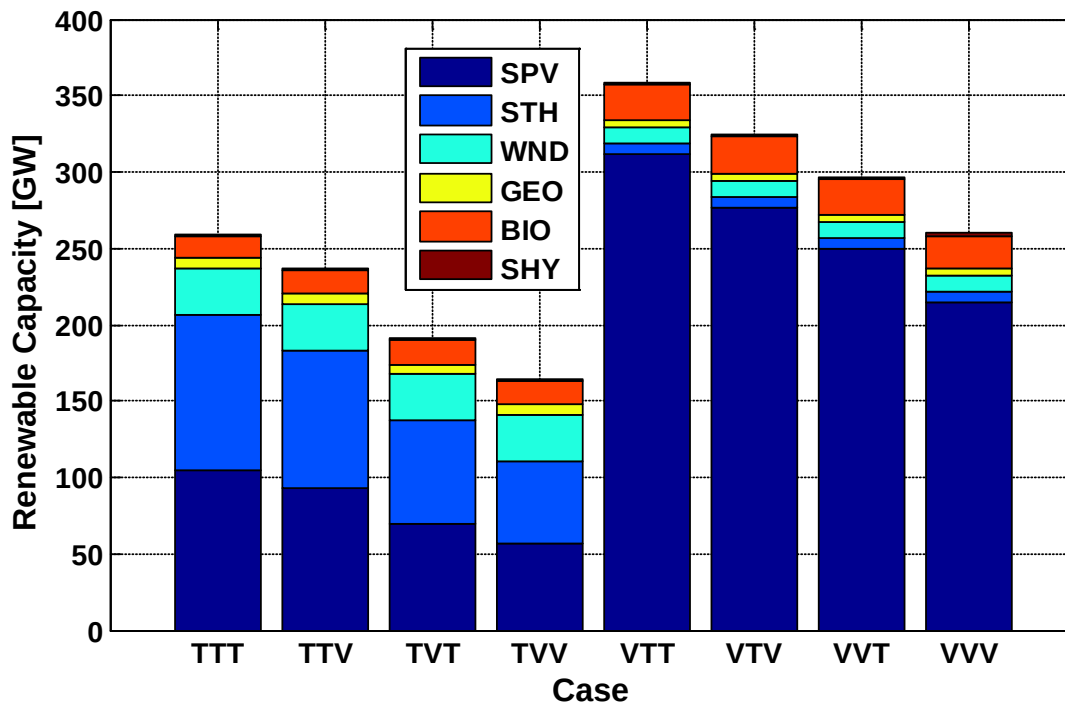


Figure 218 - Required Renewable Capacity to Meet 2050 Sustainability Goals

The required renewable capacity ranges from about 164 GW to 358 GW, depending on case.

Notable patterns emerge between the groups of cases. First, the cases with a transparent paradigm for reducing greenhouse gas emissions in the electricity sector require significantly lower installed renewable capacity levels to help the system reach the greenhouse gas reduction goal. Each “Txx” case requires approximately 65% of the total renewable capacity required to reach the greenhouse gas emissions target. This occurs due to a number of factors.

First, the transparent cases rely on a more diverse renewable portfolio. The reliance on centralized power installations for renewable and non-renewable power allows utilization of more energy from wind and geothermal power. Wind power in this region has an inherently higher capacity factor compared to solar power, allowing it to contribute more energy per unit of capacity compared to solar power. Geothermal also has very high capacity factors, even though

its potential contribution is resource limited. To some extent, the solar power profile is more spatially diverse by connecting sources from both inland and desert areas.

Second, the heavy reliance on rooftop solar PV in the visible electricity paradigm causes the aggregate renewable generation profile to be more peak-dominated. By diversifying renewables in the transparent paradigm, the average ratio of average-to-peak renewable power is lower, since not all types of renewable resources have the same temporal profile. A heavily peak-dominated renewable profile requires a significant amount of dispatchability to be able to utilize renewable generation, which potentially has energy penalties which increase the load that must be met. This is reflected in the required energy storage capacity and its effect on the grid load energy, which will be discussed in a later section.

Within a given electricity deployment paradigm, other patterns also emerge.

The cases which rely on FCVs tend to require more renewable capacity to meet the greenhouse gas emissions target compared to those which rely on BEVs. This occurs due to the fact that the electric load imposed on the grid per mile traveled is higher for hydrogen electrolyzers compared to that for electric vehicles. BEVs tend to have higher tank-to-wheel efficiencies compared to hydrogen FCVs. The required renewable capacity is about 20-25% higher for the transparent paradigm cases compared to the visible paradigm cases.

The cases which rely on visible-to-consumer water supply stabilization measures also require lower installed renewable capacities. Visible-to-consumer water supply measures such as conservation and water reuse tend to be significantly less energy intensive compared to transparent-to-consumer measures such as desalination. In some cases, due to effects on the energy consumption of the conveyance system in California, the visible measures actually have a

net-negative effect on the water-related grid load. The incremental greenhouse gas intensity of different measures was displayed in Section 6.2.

Overall, the TVV case requires the lowest renewable capacity installation. This case combines high capacity factor renewable generation with low-load options for meeting transportation sector and water supply needs. The VTT case requires the highest renewable capacity installations. This case combines highly peak-dominated renewable generation with high-load options for meeting transportation sector and water supply needs.

7.1.2.2. Energy Storage Capacity

To meet sustainability goals in the integrated system, it is not only important to supply a sufficient amount of low-carbon energy, the system must be able to utilize this energy to serve the aggregate load demand. The variable nature of many high-potential renewable resources which will be used to provide low-carbon generation to the electric grid requires that additional resources be relied upon to match supply and demand profiles at all timesteps. These additional resources can take the form of dispatchable loads, however, most dispatchable loads have strict limits on their use. For example, consider dispatching the electric vehicle charging load in the transportation sector to benefit the grid. This is limited by the patterns of when consumers charge their vehicles and the fact that the vehicle load only constitutes a portion of the total load demand and has a set peak charging/discharging capability.

While other measures are implemented in each of these cases, these measures may not be sufficient to minimize the amount of excess renewable generation. The only measure which does not have strict limits on its flexibility for shaping the load profile or its capacity is energy storage. In these cases, energy storage is tasked with bringing renewable curtailment to

acceptable levels such that excess installment of renewable capacity is avoided while also minimizing greenhouse gas emissions. The required energy storage capacities for the different cases are presented in Figure 219. In all cases, the installed energy storage types have a rated discharge time of 7.5 hours.

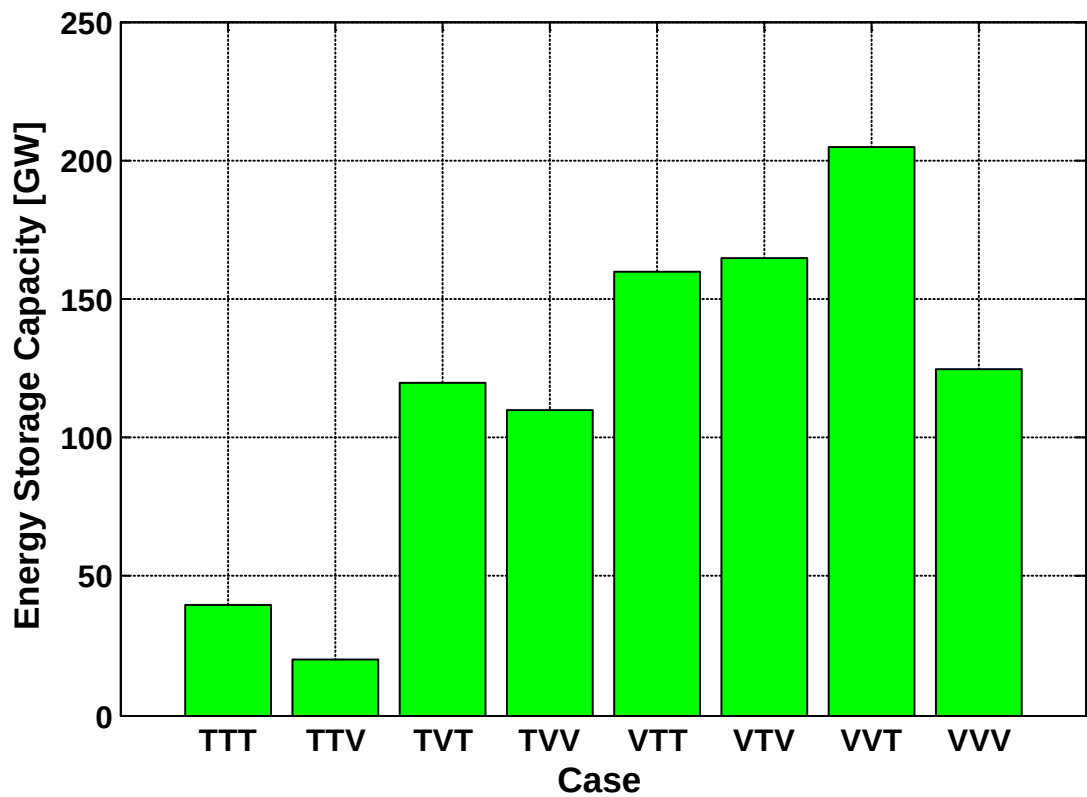


Figure 219 - Required Energy Storage Capacity for 2050 Cases

The required energy storage capacity to reduce renewable curtailment to acceptable levels and minimize greenhouse gas emissions ranges from 20 GW to 205 GW, depending on the case.

Similar to the trends for renewable capacity, the “Txx” cases require significantly less energy storage capacity compared to the “Vxx” cases. The higher peak-to-average renewable power

generation ratio in the V_{xx} cases requires higher energy storage capacities to capture energy obtained from solar PV generation.

In contrast to the trends for the required renewable capacity, the cases which rely on hydrogen FCVs “xTx” tend to require much less energy storage capacities compared to those which rely on BEVs (xVx). While the energy of the electric load due to hydrogen electrolysis is larger than that due to direct charging of BEVs, it is much more flexible in nature. This occurs since the production of hydrogen does not need to temporally coincide with the fueling of the vehicles. The production of hydrogen electrolysis takes place at centralized facilities. These facilities can shape their load profile freely, with the main constraints being the available storage of hydrogen and the need to meet the next scheduled delivery of hydrogen to stations. This allows the hydrogen electrolysis load profile to be shaped to complement renewable generation behavior. Additionally, the larger size of this load allows it to absorb more renewable generation, especially during peak solar power hours. Therefore, the ability to flexibly dispatch the hydrogen electrolysis load allows it to perform a portion of the load and supply-shifting role that energy storage would otherwise have to meet, reducing the required energy storage capacity. This is in contrast to BEVs, where the flexibility of the charging load is limited by the number of vehicles that are plugged into the grid at any given time which varies throughout the day and the need to ensure sufficient charging for consumers to meet their travel needs on a day-to-day basis. Even with charging available at both home and workplaces, the flexibility of the BEV load is still highly constrained by travel patterns.

The cases using a visible paradigm for water supply (xxV) measures require lower energy storage capacities compared to the transparent paradigm measures (xxT). This occurs due to the

lower energy requirements of consumer-involved water supply measures, which requires less renewable capacity to satisfy, and therefore less energy that needs to be shifted around. Since these loads are generally not dispatchable in either case, their effect of their energy consumption is dominant.

Overall, the TTV case requires the lowest amount of energy storage. This case combines high capacity factor and relatively steady renewable generation with highly dispatchable transportation loads, and low-energy water supply measures. The VVT case requires the highest amount of energy storage. This case combines peak-dominated renewable generation with transportation loads that have limited dispatchability and high-energy water supply measures.

7.1.2.3. Renewable Penetration Level

California has currently set targets for increasing the share of renewable resources in serving the electric load demand. The latest policy measure is SB X1-2 which calls for 20% and 33% of the electric load energy to be met by renewable generation by the years 2013 and 2020, respectively. However, no long term targets have been set which coincide with meeting the 2050 greenhouse gas reduction goal.

Meeting the 2050 greenhouse gas reduction goal must also take into account the fact that the electric load may increase at a higher rate compared to that due to population alone, due to the proposed electrification of the transportation sector. Therefore, this simulation has determined the renewable penetration level that must be reached by 2050, with consideration of interactions with the transportation and water supply sector, to meet the goals stated previously. The renewable penetration level reached for each of the different cases is presented in Figure 220, with the goals for 2013 and 2020 for comparison.

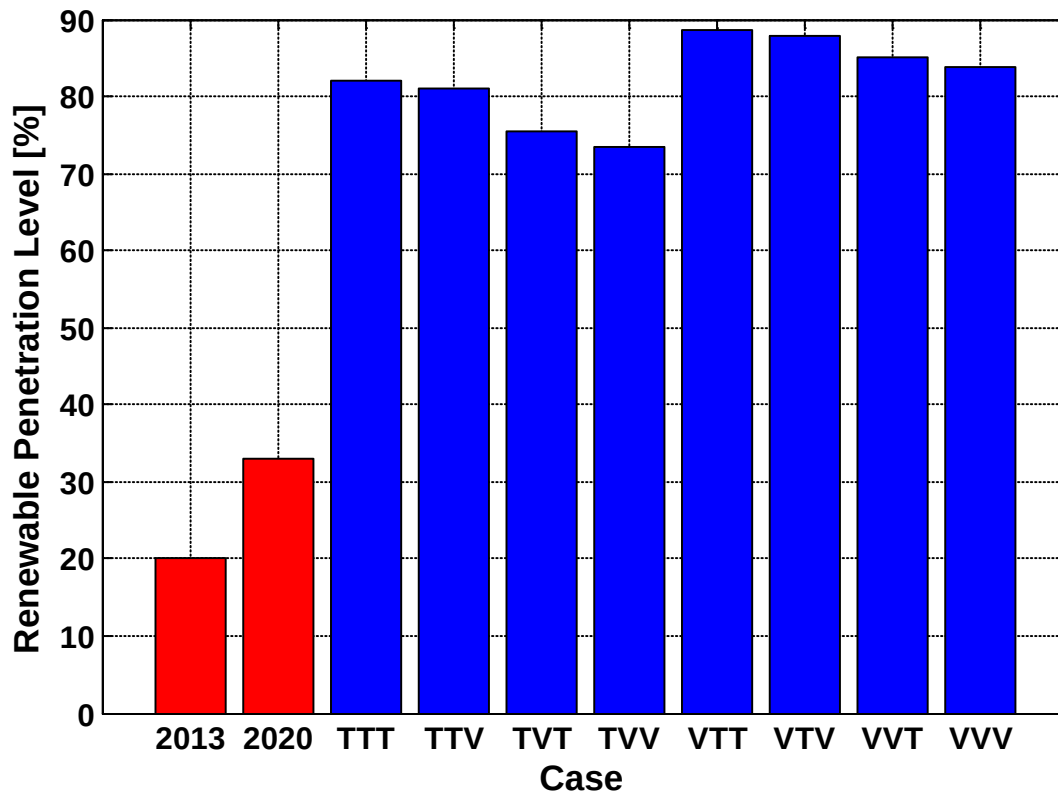


Figure 220 - Renewable Penetration Level for the 2050 Cases. Year 2013 status and Year 2020 goal included for comparison

The required renewable penetration level ranges from 73.7% to 88.7%, which are significant fractions of the total electric load demand. The “Vxx” cases tend to require slightly higher renewable penetration levels, since the balancing generators which support renewable generation in these cases are small-scale gas turbine power plants. These units are typically less efficient than those used in large-scale central generation, therefore a larger renewable contribution is required to offset emissions from these units.

The “xVx” cases which rely on BEVs do not require as much of a renewable contribution to the load demand compared to the “xTx” cases which rely on hydrogen FCVs. This occurs since in these cases, not all of the hydrogen transportation fuel is produced from electrolysis: 10% of the

hydrogen demand is still met by steam methane reformation (SMR). This process has direct greenhouse gas emissions, therefore a slightly larger renewable contribution to the combined electric load demand is required to offset these emissions to meet the greenhouse gas reduction target. These trends are also exemplified in the greenhouse gas emission breakdown for each of the cases, presented in Figure 221. Three categories are considered: emissions from the grid, emissions from gasoline vehicles, and direct emissions from other sources.

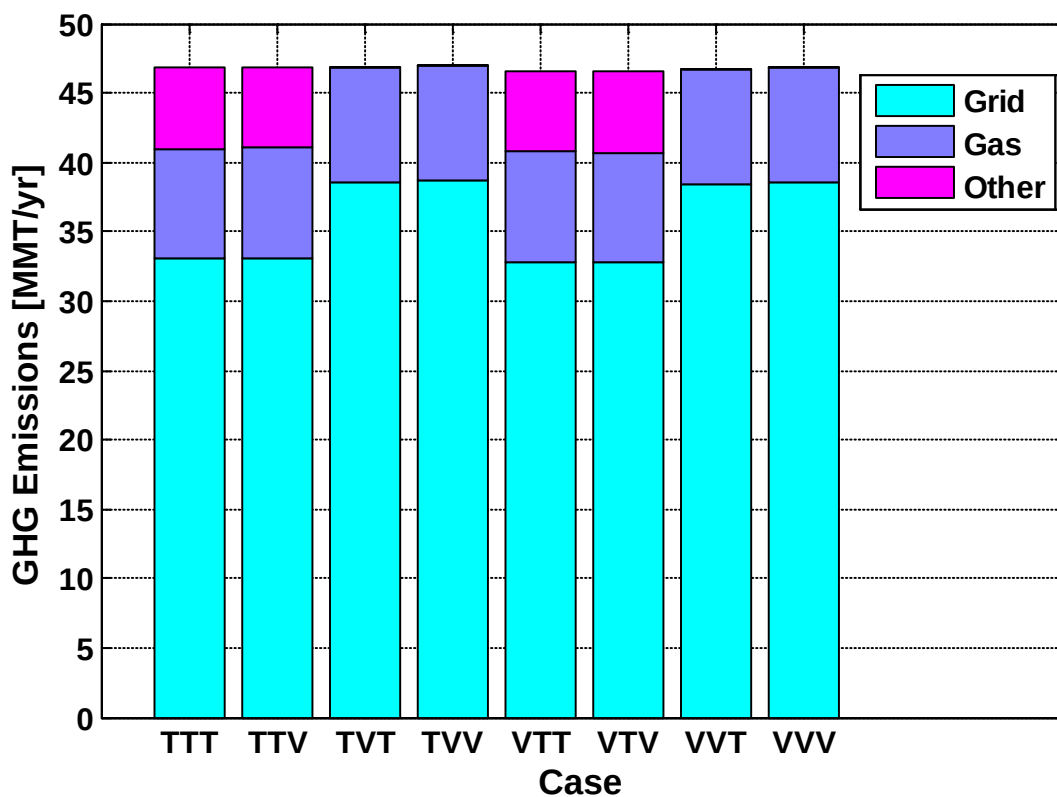


Figure 221 - Greenhouse Gas Emissions Breakdown for the 2050 Cases

The “xTx” cases have a notable amount of direct emissions that must be offset.

The “xxV” cases which rely on consumer-visible water supply measures require slightly lower renewable contributions. This is due to the electric energy consumption difference. To meet the

same greenhouse gas reduction goal with a lower total load demand, a lower fraction of that load would need to be zero-carbon compared to the case with a higher total load demand.

Overall, the TVV case requires the lowest renewable contribution to the electric load to meet a given greenhouse gas target. This combines high efficiency balancing generation with transportation options with no direct greenhouse gas emissions and low-load water supply measures. The VTT case requires the highest renewable contribution for exactly the inverse set of factors.

7.1.2.4. Primary Energy Consumption

The primary energy consumption breakdowns by sector source and by fuel type are presented in Figure 222 and Figure 223, respectively. The primary energy consumption for the year 2013 technology mix, which includes a 20% renewable penetration and 100% gasoline vehicle penetration with appropriate population levels, is included for comparison. The sector sources are broken into grid usage, gasoline (petroleum) usage, and other direct usage.

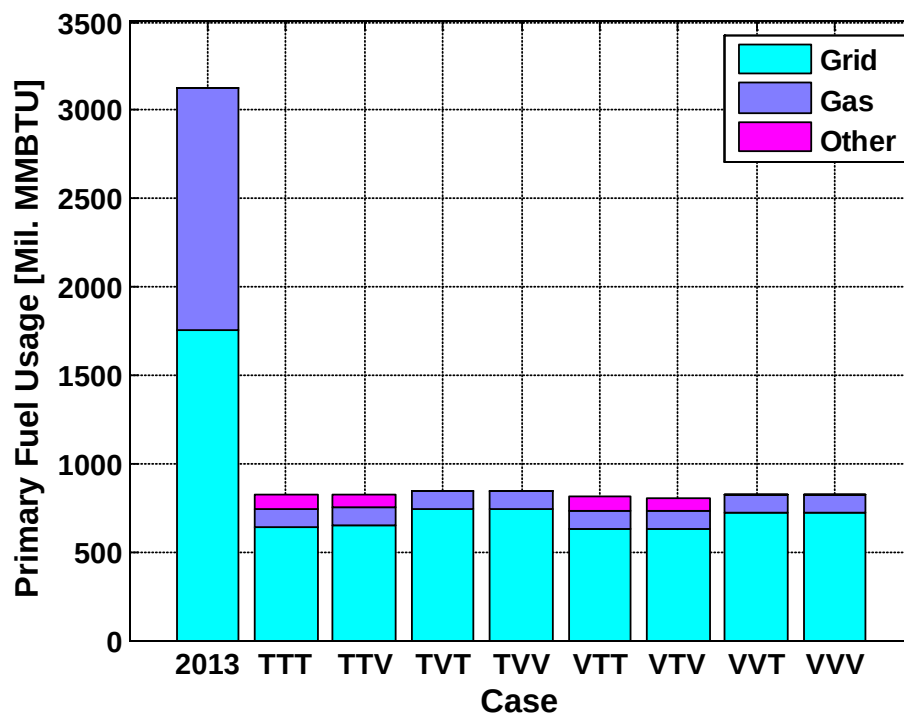


Figure 222 - Primary Energy Consumption by Sector. Year 2013 level included for comparison

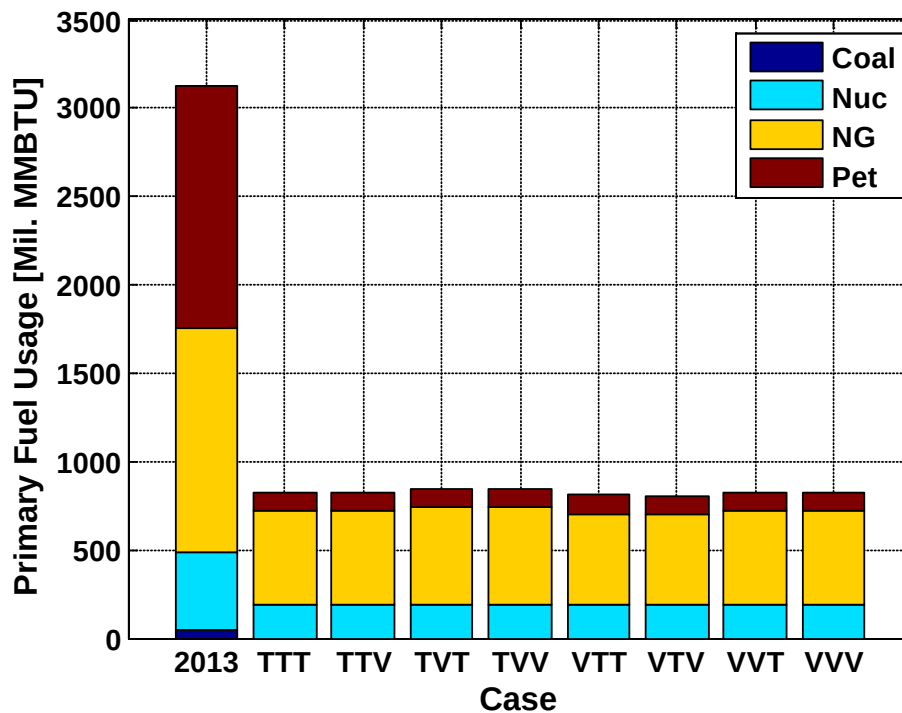


Figure 223 - Primary Energy Consumption by Fuel Type. Year 2013 level included for comparison

All of the examined cases use roughly the same amount of primary energy resources, at about roughly 820 Million MMBTU with only small variations. This is expected since the primary energy usage is strongly linked to total system greenhouse gas emissions, and all of the cases were tuned to meet the same greenhouse gas emissions goal. Direct emissions from particular processes are offset by reductions in other areas. Small differences occur primarily in natural-gas related emissions due to differences in generator dispatch.

Compared to the 2013 case, the 2050 cases use roughly 25% of the total primary energy consumption. A significant reduction in gasoline consumption takes place due to the 87% penetration of alternative fuel vehicles, and much of the energy used to meet the transportation sector fueling demand is shifted to the electricity sector. Nuclear primary energy consumption is decreased due to the assumptions described prior, and coal power is eliminated. This primary

energy consumption in these cases represents roughly 19% of what it would have been with a 2013 technology mix and a 2050 state population.

Even with an 80% greenhouse gas emissions reduction below 1990 levels, natural gas still composes a significant fraction of the primary energy consumption mix. This occurs even though a significant amount of renewable capacity and energy storage has been installed. Natural gas still remains a sizeable portion of the primary energy mix due to the need for grid reliability services. Ancillary services such as frequency regulation and spinning reserve are required to maintain the robustness of the electric service and protect the system in the event of contingencies. This is met by using power plants to perform short-timescale load following and to be online with additional available capacity to be used in the event of a contingency or forecast error. Since the resources providing these services must be dispatched on-demand, only controllable power plants with fast-response capability are used: natural-gas fueled balancing generators. In the “Txx” cases, these are large scale, natural gas combined cycle power plants, whereas in the “Vxx” cases, these refer to groups of microturbines or simple cycle gas turbine power plants. These power plant types must be online in order to respond to grid frequency deviations (regulation service) or contingencies (reserve service) on a sufficient timescale. These power plant types, however, have a minimum part-load condition within which they can operate while staying online. Therefore, to maintain required reliability services, these power plants have a minimum amount of energy that they must contribute to the load demand.

As the installed renewable capacity increases, the capacity of balancing generators that is devoted to reliability services can change. Spinning reserve service capacity is used to compensate for the loss of the largest single, firm power plant or transmission line, and is

therefore equal to the capacity of that power plant or transmission line. Therefore, spinning reserve capacity is not expected to change significantly with renewable capacity. Regulation service capacity which is used to follow fast variations in the net load demand, however, is expected to change significantly with renewable capacity. Installing the latter increases the short term variability of the net load demand, and more conventional generation capacity must be online to compensate.

The maximum regulation up and regulation down requirements for each of the cases, compared with the 2013 mix, are presented in Figure 224. Regulation up refers to capacity available to increase power as needed, whereas regulation down refers to capacity available to decrease power as needed. It is important to note that the regulation up and down capacity required at any given hour will vary depending on load and generation forecasts.

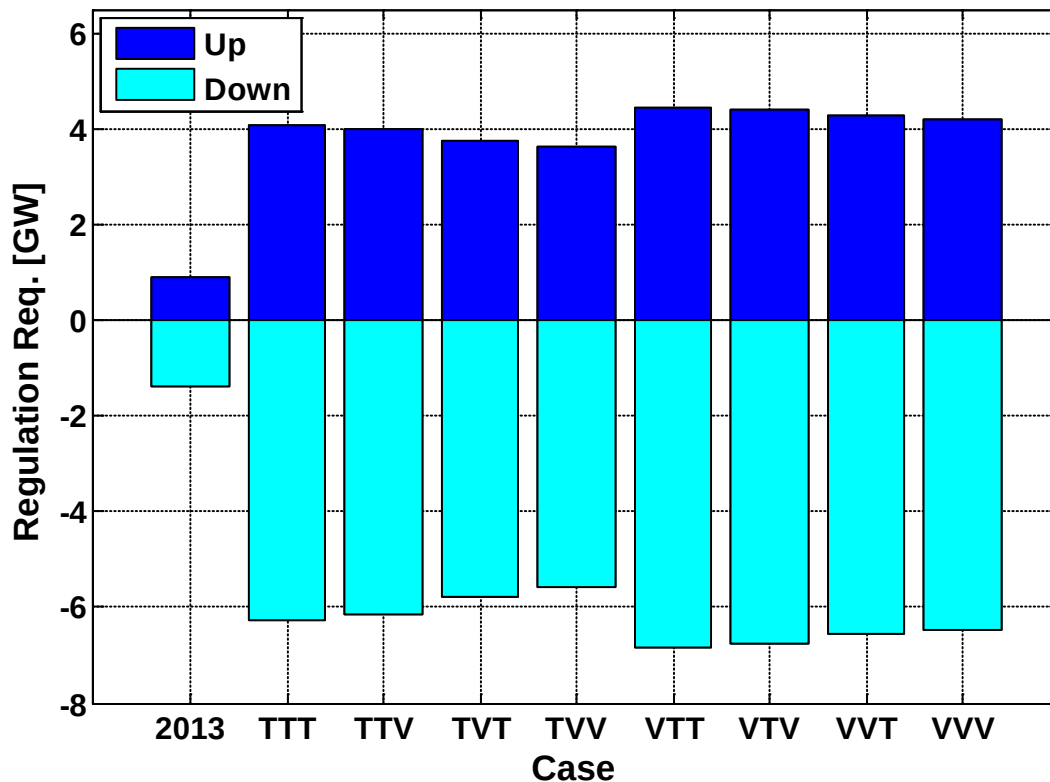


Figure 224 - Frequency Regulation Service Up and Down Requirements. Year 2013 level included for comparison.

The maximum regulation up capacity increases from about 0.906 GW in 2013 to between 3.66 and 4.44 GW. The regulation down capacity increases from 1.38 GW in 2013 to between 5.62 and 6.83 GW. Therefore, the regulation service requirement increases by about 3 to 5 times from current levels. This indicates that the minimum generation that the balancing power plants will output also increases by roughly the same factor in each case.

The contribution of natural-gas fired power plants to the load demand is therefore not trivial. The breakdown of the contribution to the electric load demand by resource type is presented in Figure 225:

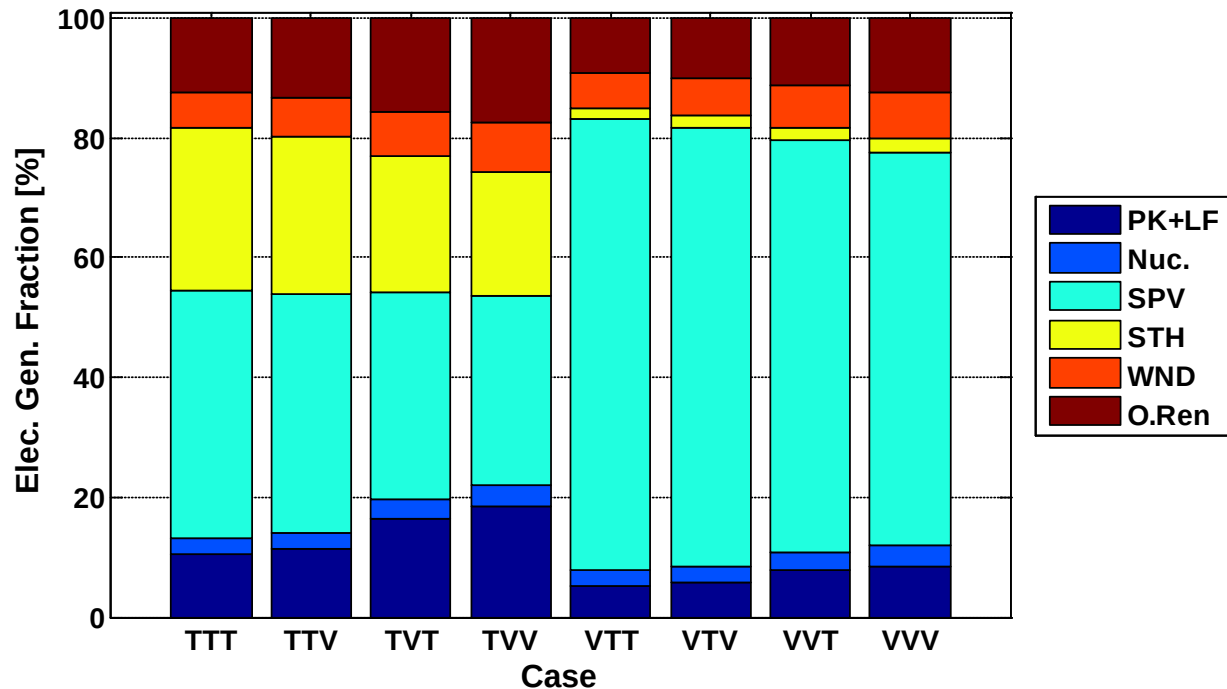


Figure 225 - Electric Energy Contribution Fraction by Resource Type

Depending on the case, natural gas power plants still provide up to 20% of the total generation used to meet the electric load demand. The “Vxx” cases which rely on distributed resources have a smaller fractional contribution from natural gas fired power plants. Minimization of this contribution is required to meet the greenhouse gas reduction goal in these cases since the natural gas power plants are less efficient than their centralized counterparts in the “Txx” cases.

Overall, this shows that fossil fuel generation will still be required to fulfill a key role in meeting greenhouse gas emissions reduction goals, even though this role will be smaller and of a different nature than that which it fulfills in today’s system. This result could change if other controllable resources could be used to provide grid reliability services, or if the dynamic operating capabilities of conventional power plant technologies improve to allow a lower minimum contribution to the load demand.

7.1.2.5. Grid Load Energy

The annual energy of the grid load demand for each of the cases is presented in Figure 226, with that for the 2013 mix for comparison. Note that this represents the energy of the load demand, which is the energy that must be delivered to consumers, not the energy supplied by generation sources. The former is modified from the latter by the losses in the transmission and distribution system, therefore the energy supplied by generation sources is slightly greater than the energy of the load demand.

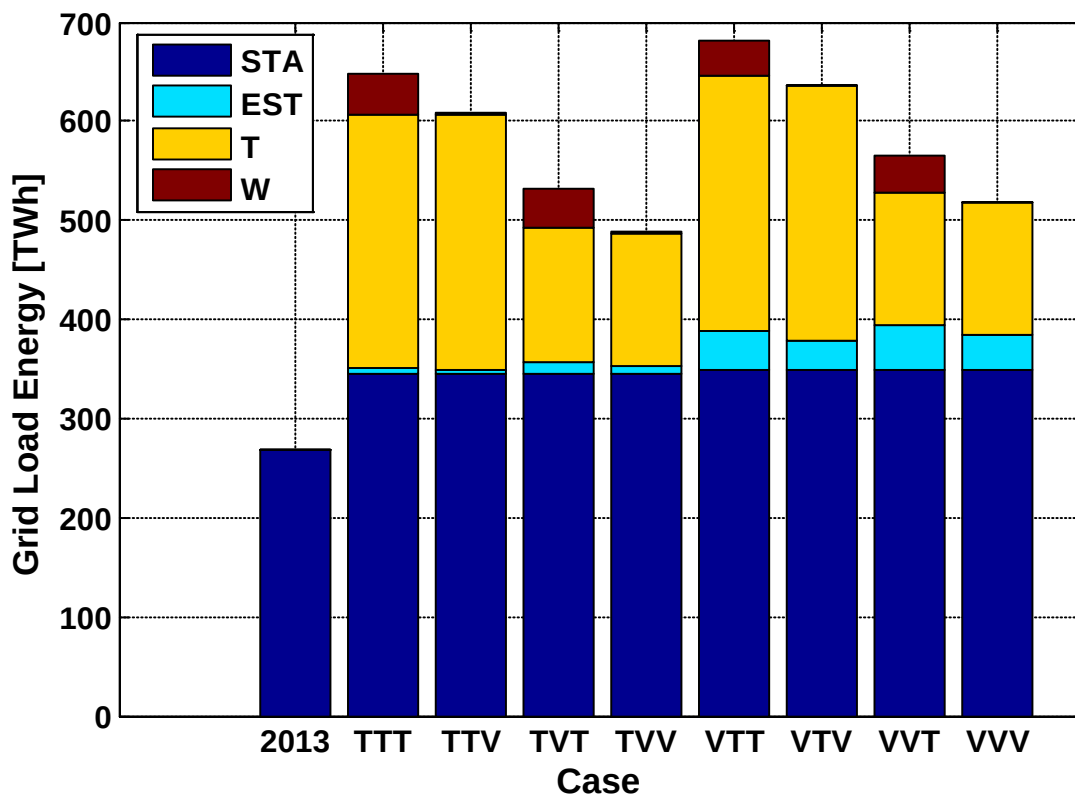


Figure 226 - Energy of the Electric Grid Load Demand. Year 2013 included for comparison.

The grid load energy has four major components:

- Stationary Load (STA): This refers to the electric load associated with stationary elements.

- Energy Storage Penalty (EST): This refers to the increase in the load demand energy due to the efficiency penalty of utilizing energy storage systems to shape the net load demand.
- Transportation (T): This refers to the additional load demand associated with electric vehicle charging and/or the production, delivery, and dispensing of hydrogen for FCVs.
- Water Supply (W): This refers to the additional load demand associated with implementing water supply stabilization measures in addition to those currently installed.

For 2013, the grid load energy is entirely stationary, since alternative transportation options, energy storage, and additional water supply stabilization measures have not been deployed to a large degree. The 2013 grid load energy was calculated by taking data from CAISO [138] for the grid load profiles in 2005, and scaling them up by population.

The stationary load is constant across all of the 2050 cases, since this is dependent mostly on population growth. Since all of these cases represent the same year, these cases have the same stationary load energy. The stationary load energy is about 29% higher than that in 2013.

The energy storage penalty is higher in the “Vxx” cases due to a number of factors. The energy storage penalty is not necessarily dependent on the capacity of the energy storage system installed, but rather on the amount of energy that passes through the system. Larger energy storage system capacities allow room for more energy to pass through the system, but the amount of energy that must pass through the energy storage system depends on the temporal characteristics of the generation mix with respect to the load demand. If the aggregate electric generation profile is relatively coincident with the profile of the load demand, then only a small amount of energy may need to pass through the energy storage system. Every unit of energy that

is stored in the system is subject to a loss due to the physical irreversibilities of the system. The larger the amount of energy that must be stored in the system to shift generation to match the load demand, the larger the total magnitude of losses. For example, consider an energy storage system with a round trip efficiency of 85%. Storing 1 GWh will allow 0.85 GWh to be available for meeting the load demand, with a total loss of 0.15 GWh. Storing 2 GWh of energy will allow 1.7 GWh of energy to be available for meeting the load demand, with a total loss of 0.3 GWh. This loss of energy from generation sources manifests as an increase in the load demand.

The “Vxx” cases rely heavily on Solar PV, therefore the generation profile in these cases is not as coincident with the load demand profile as that in the “Txx” cases, which uses a more diverse renewable mix which is more coincident with the load demand profile. Therefore, the “Vxx” cases require a larger amount of energy from generation sources to be shifted to meet the load demand, necessitating larger energy storage capacities as discussed previously. This is evident in the timeseries plots of the TTV and VTT cases, as shown in Figure 227 and Figure 228.

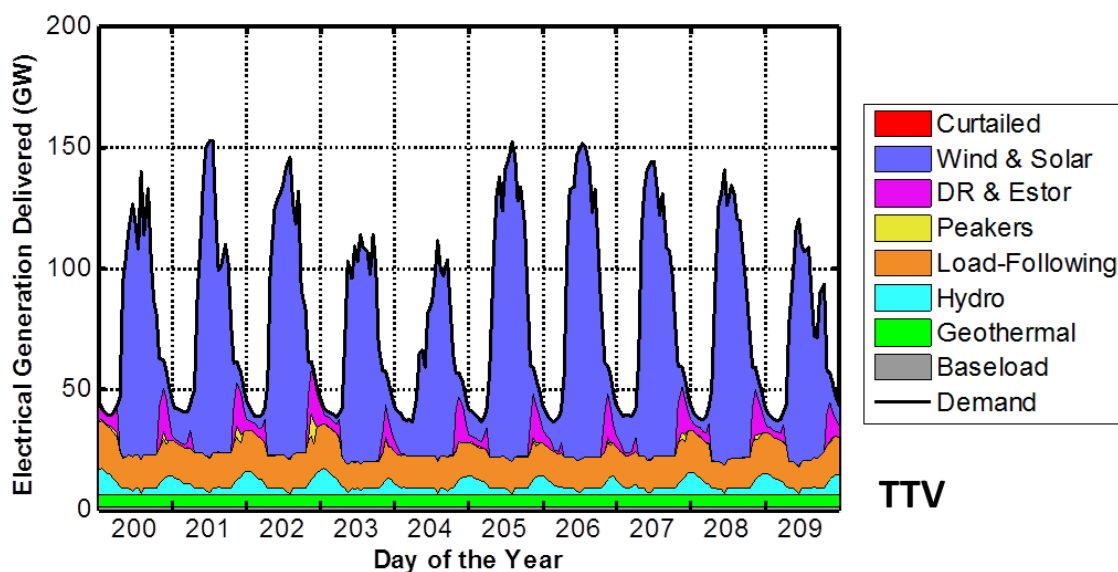


Figure 227 – Time Series of Generation Profiles - TTV Case

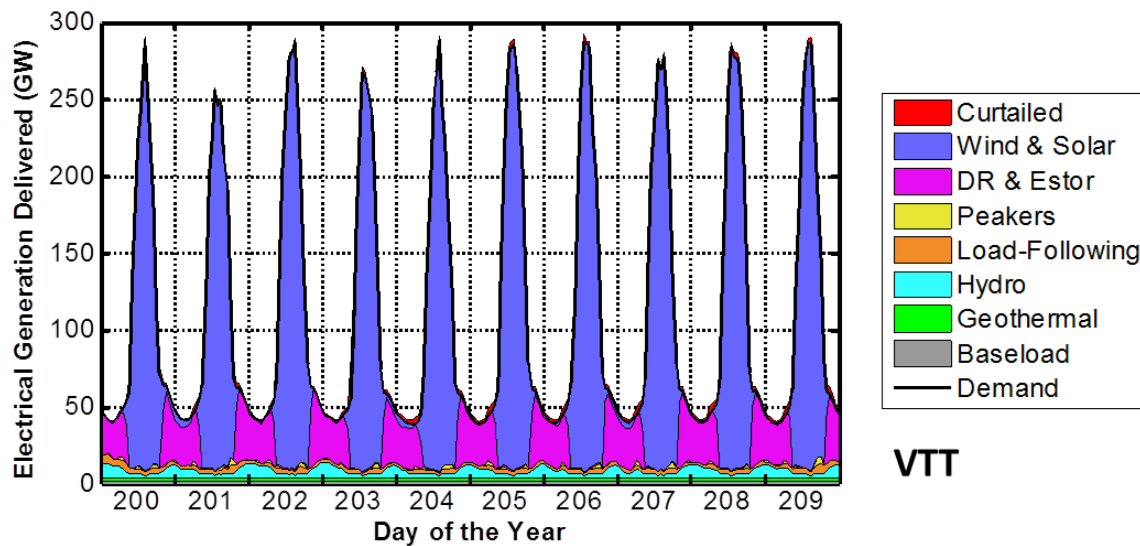


Figure 228 – Time Series of Generation Profiles - VTT Case

In the VTT timeseries, energy storage discharge contributes towards meeting a large portion of the load demand, indicating high generation-shifting. Within the “Vxx” cases, the VTT case has the highest energy storage penalty and also requires the largest energy storage capacity. The VTT case, while having a slightly lower energy storage capacity than the VTV case, requires more energy to pass through the energy storage system. This occurs since the transparent-paradigm water supply measures rely on desalination which has a steady electric load profile, making the aggregate load demand profile less coincident with the solar PV-reliant generation profile.

The transportation load energy depends strictly on the technology utilized. The “xTx” cases, which rely on hydrogen FCVs, impose a larger electric load demand on the grid. This result is expected since hydrogen FCVs are generally less efficient on a tank-to-wheels basis compared to electric vehicles. Additionally, with a heavy reliance on electrolysis for the production mix, the losses incurred on the pathway from primary energy to on-board vehicle fuel are higher. For a

hydrogen FCV using hydrogen from electrolysis, a unit of electric energy supplied by the grid is subject to the electrolyzer efficiency penalty and the losses due to the delivery and dispensing of hydrogen before it manifests as transportation fuel. For a BEV, that same unit of supplied electric energy is subject only to the vehicle charging unit losses before manifesting as transportation fuel. Therefore, to meet the same amount of vehicle-miles-traveled, it is expected that the electric load energy due to using hydrogen FCVs is higher than that for BEVs. In these cases, the annual BEV-related electric load is about 135 TWh, which is about 52% of the FCV-related electric load of about 257 TWh.

The water supply load energy is distinctly smaller in the “xxV” cases, compared to the “xxT” cases. This result is also expected since the visible-to-consumer water supply stabilization measures – conservation and water reuse – impose low and even negative electric load impacts due to low direct electricity consumption and offsetting loads due to the conveyance of water. The transparent-to-consumer water supply stabilization measures are composed primarily of membrane desalination, which has a relatively high electric energy consumption compared to other measures. Overall, however, the electric load energy due to water supply measures are relatively small compared to that imposed by the other three components, even in the “xxT” cases.

Overall, the VTT case exhibits the highest grid load energy. This case combines high transportation loads with energy-intensive water supply measures, and requires a large amount of generation-shifting which increases the energy storage penalty. The TVV case exhibits the lowest grid load energy. This case combines low generation-shifting requirements with low transportation loads and low-energy water supply measures.

7.1.2.6. Change in Combined Water Consumption and Required Water Supply Stabilization Capacity

The change in the average annual water consumption from historical levels is presented in Figure 229a due to changes in the electric grid and transportation sector technology portfolio, with an inset in Figure 229b. The change in the urban and agricultural water demand is also included for comparison, sourced from projections of the California Department of Water Resources [48]. A negative value indicates a reduction in water demand relative to current levels.

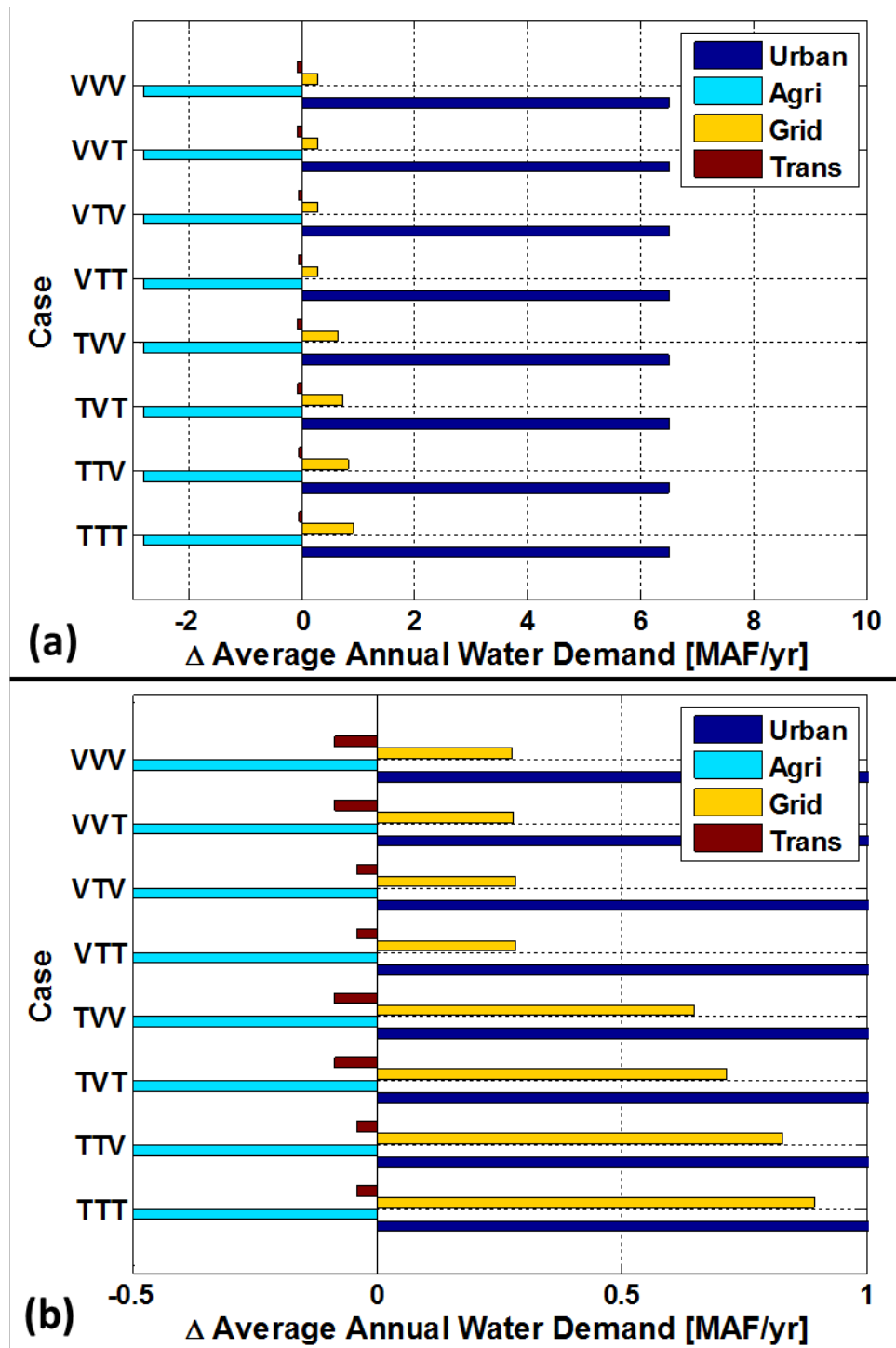


Figure 229 - Change in Average Annual Water Demand from Historical Levels

The “Vxx” cases tend to have a smaller increase in grid-related water demand compared to the “Txx” cases. The primary source of water demand increase in the “Vxx” cases is the conversion

of power plants using once through cooling (withdrawal) to cooling towers (consumptive), combined with an increase in power plant capacity. Cooling towers require less water to be extracted compared to once-through cooling, and have lower environmental footprints, but this water is supplied by managed reservoirs as opposed to the ocean, and is not returned to those reservoirs. This increases the consumptive water demand of the electric grid. To meet the 2050 GHG emissions reduction goal, however, the grid relies heavily on renewable resources. These resources tend to consume equal to or less water than conventional power plants [49], which offsets the increase due to the conversion of conventional power plants to cooling towers. The difference between the “Vxx” cases and the “Txx” cases is due to the renewable mix in this case. The “Vxx” cases rely strongly on fixed solar PV, which consumes little to no water. The “Txx” cases rely strongly on solar thermal power, however, which tends to consume more water compared to conventional power plants. Differences within the “Txx” and “Vxx” cases are dependent on the load demand that must be met: larger load demand requires more water-consuming generation. The grid-related average annual water demand anomaly ranges from +0.276 MAF/yr to +0.895 MAF/yr, depending on the case.

The direct transportation water demand anomaly is very small in all cases compared to that of the grid, and is also uniformly negative. This occurs since implementing alternative transportation options decreases the production of gasoline fuel and therefore its corresponding water consumption. BEVs impose no direct water demand, since their primary effect is through the grid. Hydrogen production for FCVs primarily affect water demand through the loads that it imposes on the grid, however, it also contains elements which consume water directly: electrolysis and steam-methane reformation processes. These elements, however, are relatively

small. The direct water demand anomaly for the transportation sector ranges from -0.0874 MAF/yr to -0.041 MAF/yr, with the higher values corresponding to the cases using FCVs.

Overall, however, compared to the water demand anomaly that is associated with non-electric grid, non-transportation elements in operation, the water demand anomalies for the grid and transportation sectors are relatively small. This indicates that while transportation and electric grid operations have an impact on the water supply, they are not the most significant factors. It is important to note, however, that this is for water demand anomalies in operation, not necessarily life-cycle, of transportation and electric grid elements.

These trends give rise to the following required capacities for the water supply stabilization measures in each of the cases to secure the surface reservoir levels, presented in Table 71:

Table 71 - Required Water Supply Stabilization Measures for the 2050 Cases

<u>Case</u>	<u>Urban Water Conservation</u> <u>[Mm³/d]</u>	<u>Water Reuse</u> <u>[Mm³/d]</u>	<u>Thermal Desalination w/ Waste Heat</u> <u>[Mm³/d]</u>	<u>Membrane Desalination</u> <u>[Mm³/d]</u>
TTT	2.375	0	0	32.600
TTV	9.502	18.446	3.632	7.000
TVT	2.375	0	0	32.000
TVV	9.502	18.446	3.632	6.500
VTT	2.375	0	0	30.500
VTV	9.502	18.446	3.632	5.700
VVT	2.375	0	0	30.500
VVV	9.502	18.446	3.632	5.800

Since the shortfall of water supply due to precipitation is significant under climate change conditions, the capacities of water supply stabilization measures needed to secure the surface reservoir levels are significant. In all “xxV” cases, the entire potential for urban water conservation, water reuse, and thermal desalination with waste heat must be used, and some

desalination capacity must still be installed in addition to these. Differences between cases with equivalent electricity and transportation paradigms therefore manifest as differences in membrane desalination capacity. The “xxT” cases use their entire allotment of urban water conservation measures, and rely on a significant amount of membrane desalination to meet water supply needs. Few differences exist between the required capacities for the “xTx” and “xVx” cases. The direct water consumption effect between both BEVs and FCVs is small. The only difference primarily manifests as the difference between the need to cool the additional power plants installed to meet the vehicle charging or hydrogen infrastructure loads, with the latter being larger and therefore requiring more desalination capacity. More noticeable differences exist between the “Txx” and “Vxx” cases, with the former requiring more desalination capacity, due to the difference in grid water demand.

7.1.2.7. Cost of Energy per Capita

The Cost of Energy per Capita (CEPC) is an annual indication of the cost to meet the energy needs of the population associated with electricity and transportation. The CEPC is calculated as the total amount of funds spent on providing electric energy and transportation fuel to meet the demand in a given year, normalized by the population of the state. An aggregate metric is used to represent costs, since due to the effects of interactions between the operations of different sectors, costs may be reduced in one sector but increased in another sector. For example, installing BEVs reduces costs due to gasoline expenditure, but imposes an electric load on the grid which influences the cost of electricity. Therefore, it is the total cost of energy to meet these services that must be examined. The CEPC and corresponding component breakdown for the 2050 cases is presented in Figure 230, with the metric for the 2013 mix included for comparison. The CEPC for the year 2013 was calculated by installing the mix of renewable resources present

at the end of the year 2013 into the HiGRID model, along with average gasoline prices for the year [187], deflated to 2005 dollars to be consistent with all of the other economic units in the model.

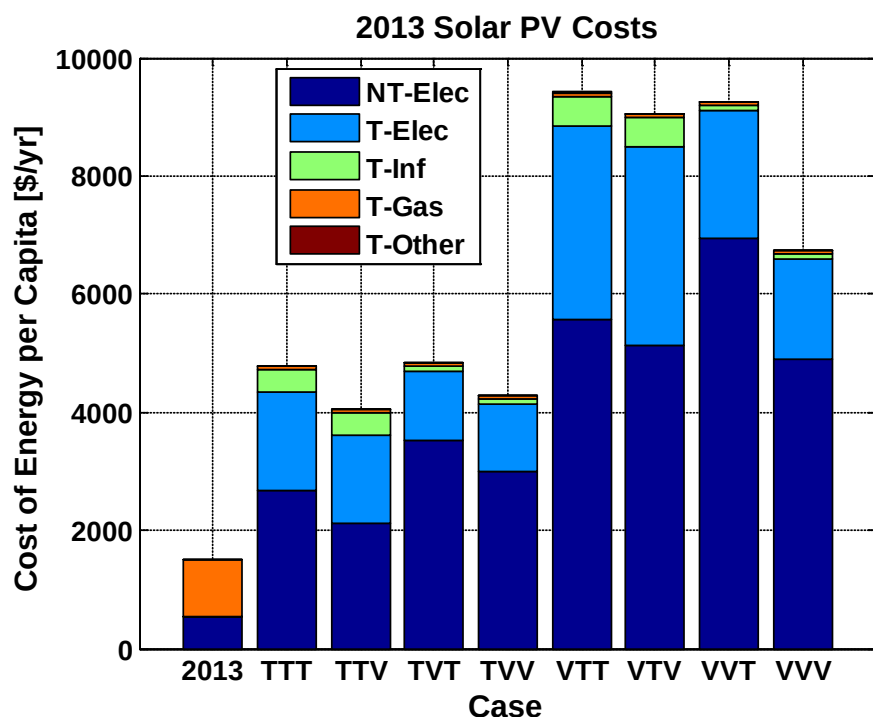


Figure 230 - Cost of Energy per Capita for the 2050 Cases with Year 2013 Solar PV Costs. Year 2013 levels included for comparison

Sensitivities to the installed cost of solar photovoltaic and battery energy storage are also performed. The CEPC for the all of the cases are determined using current (year 2013) installed solar PV capital costs in California, as obtained from the NREL Open PV project [349], and subsequently with 50%, 75%, and 90% reductions from those levels to examine the sensitivity to solar PV costs. Additionally, the CEPC is also calculated for cases with 50% and 90% solar PV cost reductions in combination with a 50% reduction in the installed capital costs of vanadium flow battery (VFB) energy storage. These scenarios and the corresponding cost figures are presented in Table 72:

Table 72 - Solar PV and VFB Cost Sensitivity Parameters

<u>Scenario</u>	<u>Fixed Rooftop PV Cost [\$ /kW]</u>	<u>1-Axis Tracking PV Instant Cost [\$ /kW]</u>	<u>Vanadium Flow Battery Instant Cost [\$ /kW]</u>
2013 Solar PV Cost	4080.00	2782.00	3100.00
50% Solar PV Cost Reduction	2040.00	1391.00	3100.00
75% Solar PV Cost Reduction	1020.00	695.50	3100.00
90% Solar PV Cost Reduction	408.00	278.20	3100.00
50% Solar PV Cost Reduction + 50% VFB Cost Reduction	2040.00	1391.00	1550.00
90% Solar PV Cost Reduction + 50% VFB Cost Reduction	408.00	278.20	1550.00

The CEPC is broken down into five primary components.

- Non-Transportation Electricity (NT-Elec): This refers to the cost of providing electric energy to meet the load demand not associated with transportation fuel production. This is calculated by determining the levelized cost of electricity for each case, multiplying it by the non-transportation electric load demand, and normalizing by the state population.
- Transportation Electricity (T-Elec): This refers to the cost of providing electric energy to meet the load demand associated with providing transportation fuel, such as charging of BEVs and FCV infrastructure loads. This is in the same manner as the non-transportation electricity component, but multiplying the levelized cost of electricity by the transportation-related electric load demand.
- Transportation Infrastructure (T-Inf): This refers to the cost of financing the infrastructure required to provide transportation fuel for either BEVs or FCVs, depending

on case. For BEVs, this is calculated by determining the number of charging stations required based on the number of vehicles deployed, and multiplying it by the cost per charging station as specified by [350]. For FCVs, this is calculated by determining the cost-per-kg components of non-feedstock related hydrogen infrastructure costs, and multiplying by the total hydrogen demand accordingly.

- Transportation Gasoline (T-Gas): This refers to the cost of gasoline fuel. This is calculated by taking the cost of gasoline and multiplying it by the gallons used, which is an output of the model. In these cases, the cost of gasoline is assumed to be the same as current levels.
- Transportation Other (T-Other): This refers to non-electricity, non-infrastructure costs associated with providing transportation fuel. This primarily refers to direct natural gas costs for use in the SMR process for FCV production.

7.1.2.7.1. Base Case: 2013 Solar PV Costs

The reference CEPC value for the 2013 mix is about \$1490/yr. In the 2050 cases, this value increases to between \$4050/yr and \$9420/yr using 2013 solar PV costs, which represent increase factors of between 2.71 to 6.32. This signifies that at current cost rates, the cost of energy will increase regardless of which pathway is used to meet the 2050 greenhouse gas reduction goals.

The “Txx” cases exhibit significantly lower costs of energy per capita compared to the “Vxx” cases. This occurs since the levelized cost of electricity is significantly reduced in the “Txx” cases relative to the “Vxx” cases due to reliance on a more diverse renewable portfolio and lower required energy storage capacities. The levelized cost of electricity for the 2050 cases, using 2013 solar PV costs, is presented in Figure 231.

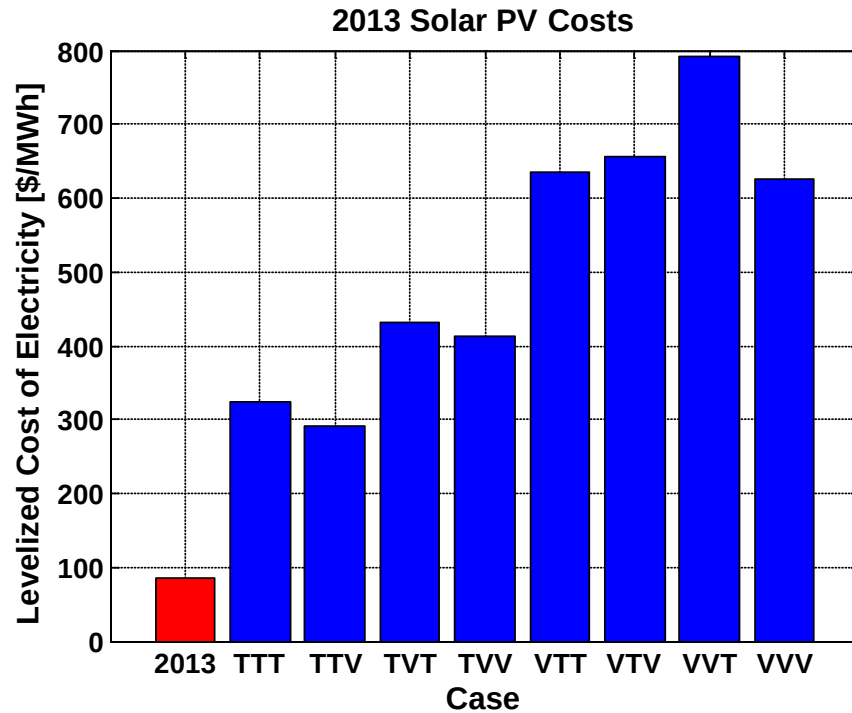


Figure 231 - Levelized Cost of Electricity for the 2050 Cases using Year 2013 Solar PV Costs. Year 2013 included for comparison

The renewable portfolio in the “Txx” cases utilizes a higher percentage of wind, geothermal, centralized solar PV and solar thermal capacity. Both wind and geothermal power plants tend to have lower associated capital costs compared to solar power plants, since only conventional materials and manufacturing techniques are required to produce these units. The renewable portfolio of the “Txx” cases also exhibit higher capacity factors. Geothermal power has a very high capacity factor relative to variable renewable resources, on the order of 70-85%. In California, the high wind resource areas in the southeastern areas of the state exhibit wind capacity factors of 30-40%, which is also higher than solar power. Centralized solar power plants in the state can be sited in areas with high incident radiation, also in the southeastern area, compared to population centers on the coast. These units can also make extensive use of solar tracking for both PV and thermal power plants, which allow capacity factors of about 25%

compared to about 19% for southern coastal areas, and lower for northern coastal areas. High capacity factors indicate that the less capacity will need to be installed per unit of energy obtained from that resource. This trend is also evidenced by the required renewable capacity for each of the cases as discussed earlier.

The benefits of the “Txx” cases seem to outweigh the lack of required transmission costs in the “Vxx” cases. It is important to note that the transmission costs used do not include additional expenditures associated with overcoming social opposition and legal fees, which may alter the result slightly.

Higher costs of electricity affect the two major cost components of the CEPC, since it increases the costs of both non-transportation and transportation-related electric energy usage. Electricity-related feedstock costs are shown to be the largest factors in determining the CEPC, dwarfing transportation infrastructure costs at this market penetration of alternative vehicles considered in these cases. Therefore, reducing the levelized cost of electricity is an important consideration for determining the CEPC.

The contribution of the non-feedstock related hydrogen infrastructure costs to the CEPC also varies between “TTx” and “VTx” cases. The “VTx” cases exhibit higher hydrogen infrastructure costs since dispatching the electrolysis load to accommodate the peak-dominated generation profile in these cases causes the electrolyzers to have lower capacity factors, as exhibited in Figure 232. This requires hydrogen to be sold at more expensive rates to compensate in order to finance the capital cost of the electrolyzers.

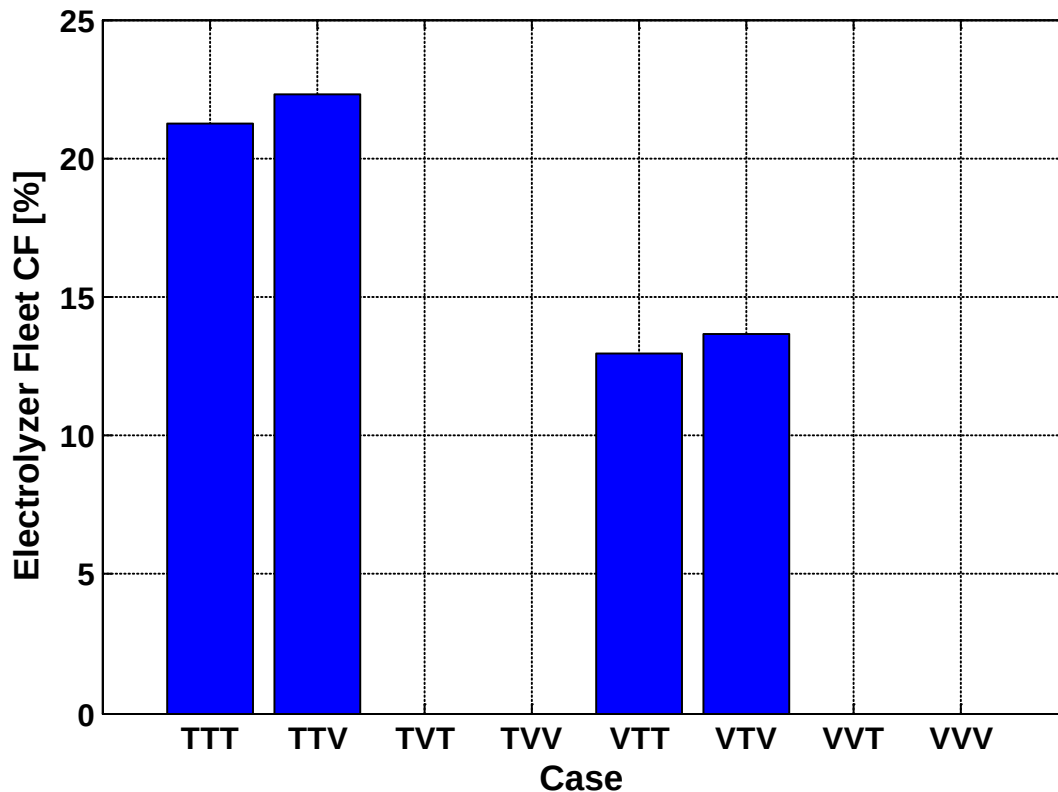


Figure 232 - Electrolyzer Fleet Capacity Factors for the FCV-reliant cases

Within a given “Txx” or “Vxx” group of cases, the difference in the CEPC is due to the ability to match generation profiles with load profiles, and the magnitude of the associated loads.

Additional equipment is needed to allow generation profiles to coincide with load profiles when relying heavily on variable renewable resources. This additional equipment carries significant costs. Therefore, minimizing the amount of this additional equipment is very beneficial for the cost of electricity, and therefore the CEPC. If currently installed resources can provide that benefit with costs that would have had to be incurred anyway, this can limit increases in the cost of electricity.

Within the “Txx” cases, the lowest CEPC is obtained for the TTV case. This case uses low-energy water supply options and relies on hydrogen FCVs. This case has the lowest CEPC

regardless of the fact that it has a higher electric load demand compared to the TVV case, due to hydrogen electrolysis. This occurs due to the dispatchability of the hydrogen electrolysis load, and has a very important implication for the business case for FCVs. As discussed earlier, the hydrogen electrolysis load is more flexible than the BEV charging load due to its centralized, transparent nature and relative decoupling from consumer fueling patterns. This allows it to shape its load profile to help the aggregate load profile to coincide more with the aggregate generation profile, reducing energy storage capacities as discussed earlier, and therefore energy storage costs. This causes the levelized cost of electricity to be lower in the TTV case compared to the TVV case. While the transportation-related electricity cost is larger on an absolute basis due to the larger electric load magnitude, the non-transportation related electricity cost is lower due to this effect. The net effect is to allow a case that has high electric loads but more flexible technologies to be a cheaper way of meeting the 2050 GHG emissions reduction goal compared to one with lower loads but also lower flexibility. This emphasizes the importance of flexible load dispatch in meeting sustainability goals.

For the “Vxx” group of cases, the VVV case has the lowest CEPC, in contrast to the “Txx” group of cases. This occurs since in the “Vxx” cases, the levelized cost of electricity is very high due to the heavy reliance on fixed solar PV technologies and the requirement for extreme amounts of energy storage. Since electricity is so expensive, reduction in the magnitude of the load demand is more important than dispatchability for determining costs. The cheapest “Vxx” case, however, is still more expensive than all of the “Txx” cases with 2013 Solar PV costs.

The effect of water stabilization measure paradigm on the CEPC is primarily based on its energy intensity. “xxV” cases have lower energy consumption, therefore lower contributions to the non-transportation electricity costs.

7.1.2.7.2. Solar PV Cost Sensitivity:

The effects of reducing the installed capital cost of solar PV on the CEPC is presented in Figure 233, Figure 234, and Figure 235 for 50%, 75%, and 90% reductions from current levels, respectively.

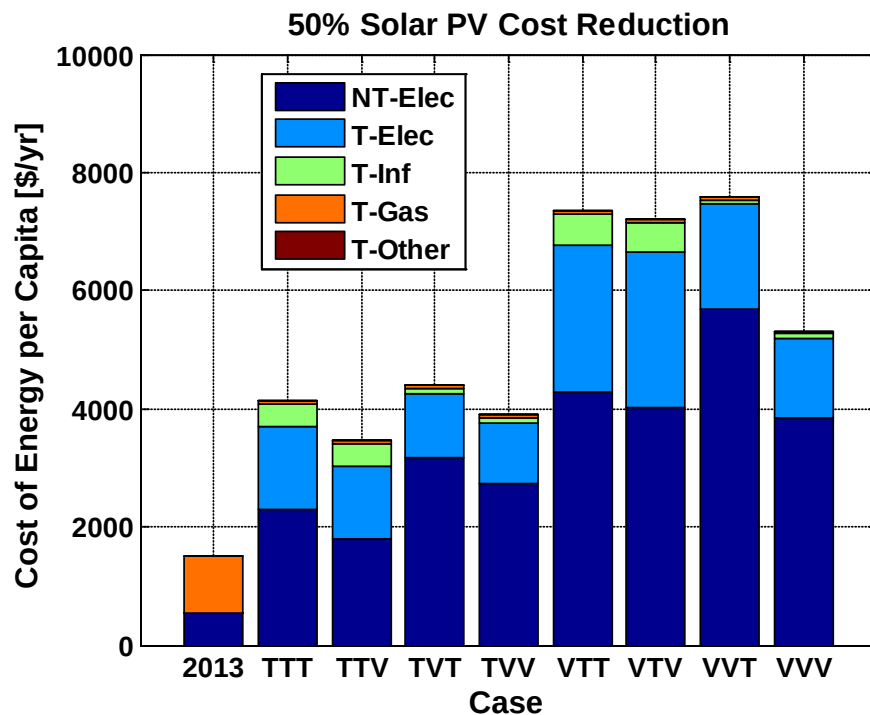


Figure 233 - Cost of Energy per Capita for the 2050 Cases with 50% Solar PV Installed Capital Cost Reduction. Year 2013 included for comparison

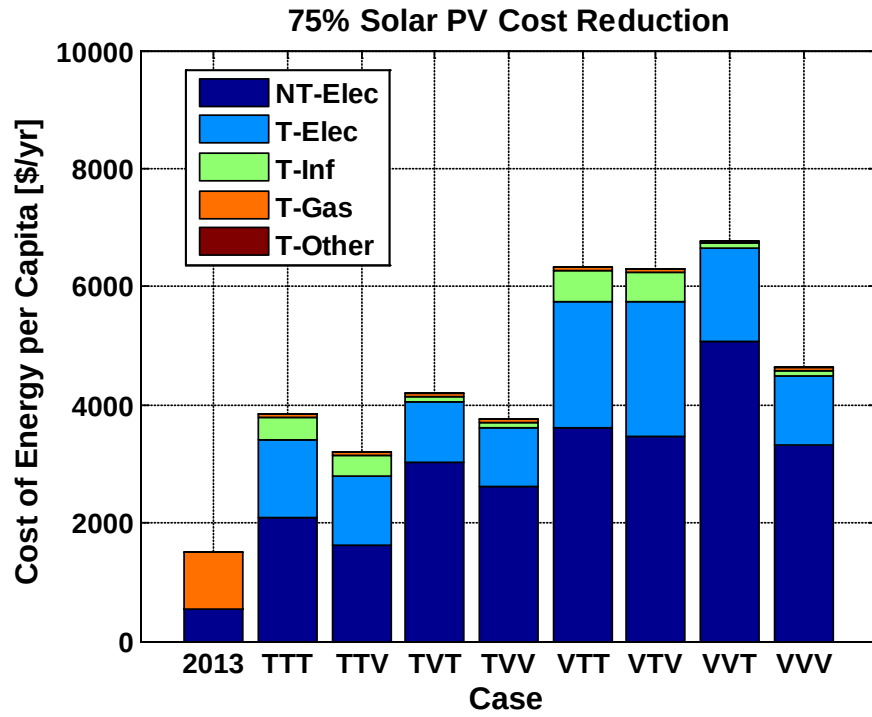


Figure 234 - Cost of Energy per Capita for the 2050 Cases with 75% Solar PV Installed Capital Cost Reduction. Year 2013 included for comparison

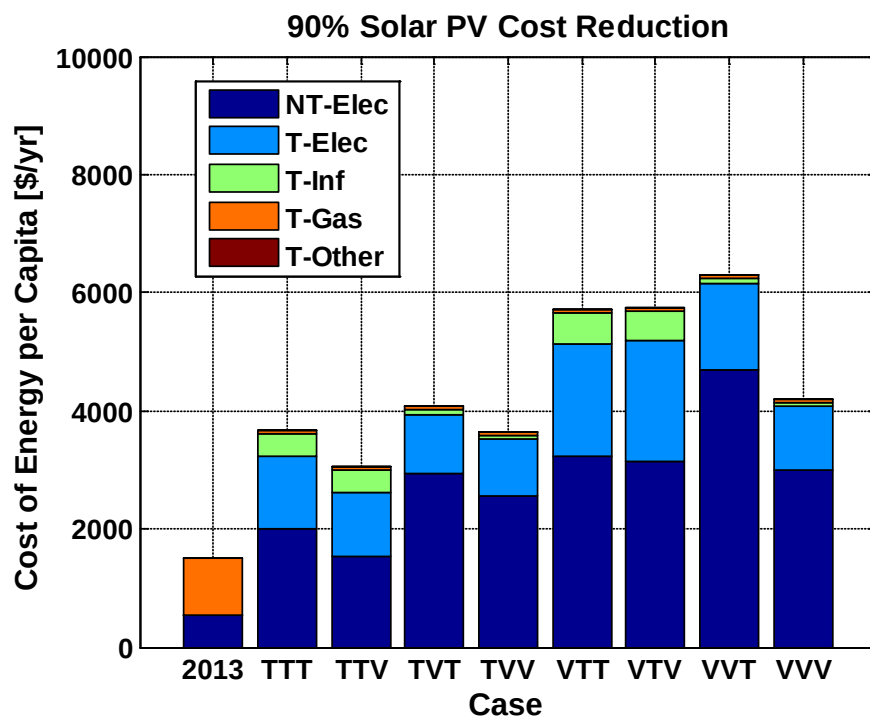


Figure 235 - Cost of Energy per Capita for the 2050 Cases with 90% Solar PV Installed Capital Cost Reduction. Year 2013 included for comparison

As expected, the CEPC decreases as the solar PV installed capital cost is reduced. For 50%, 75%, and 90% installed capital solar PV cost reductions, the change in the CEPC relative to current levels is reduced to between 2.33 to 5.08, 2.15 to 4.54, and 2.04 and 4.21 multiples of current levels, respectively. This is compared to 2.71 to 6.32 with year 2013 installed capital solar PV costs. Correspondingly, this is due to reductions in the levelized cost of electricity, presented for 50%, 75%, and 90% installed capital solar PV cost reductions in Figure 236, Figure 237, and Figure 238, respectively:

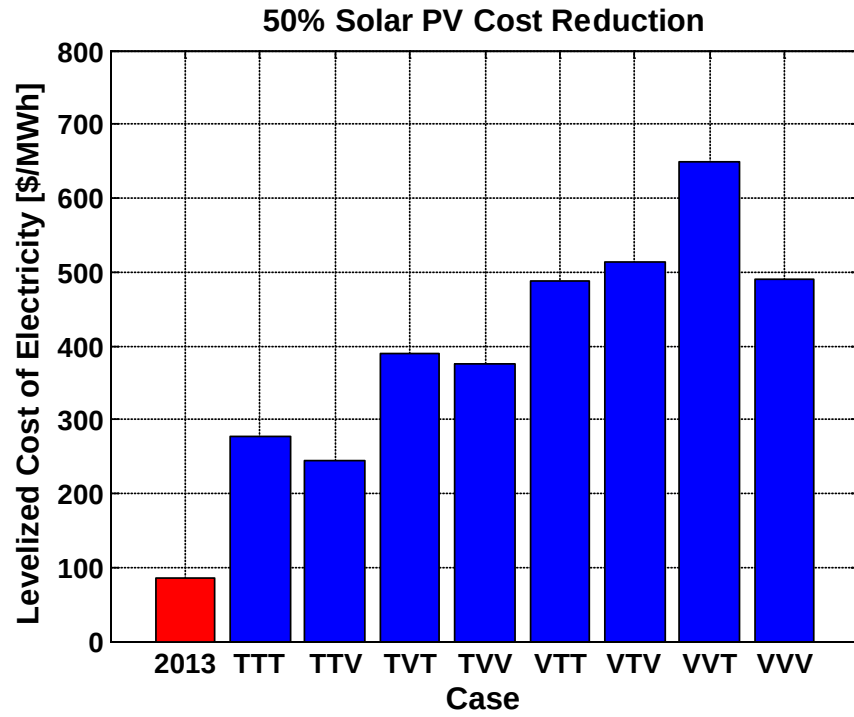


Figure 236 – Levelized Cost of Electricity for the 2050 Cases with 50% Solar PV Installed Capital Cost Reduction. Year 2013 included for comparison

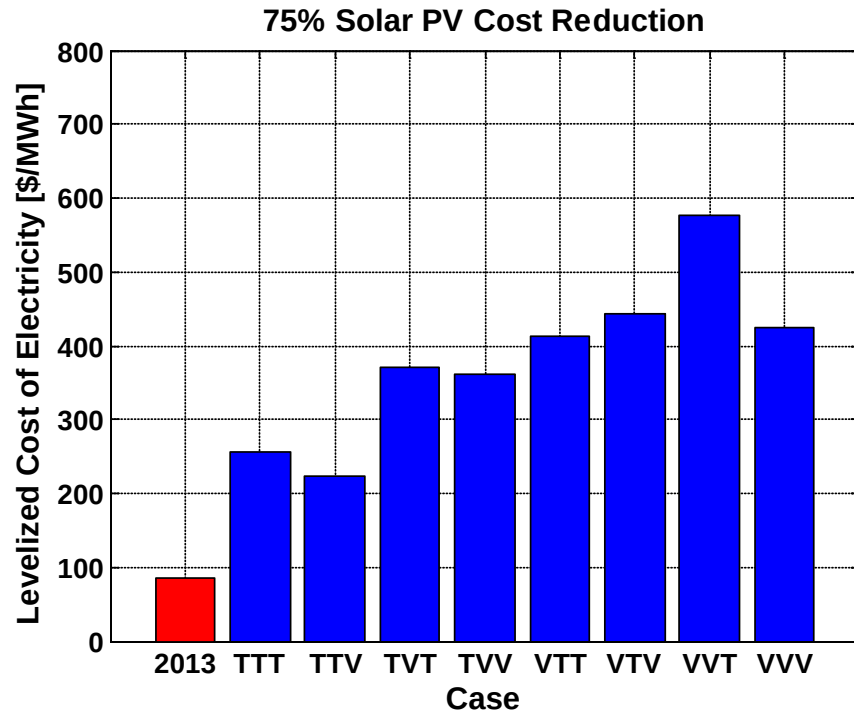


Figure 237 - Levelized Cost of Electricity for the 2050 Cases with 75% Solar PV Installed Capital Cost Reduction. Year 2013 included for comparison

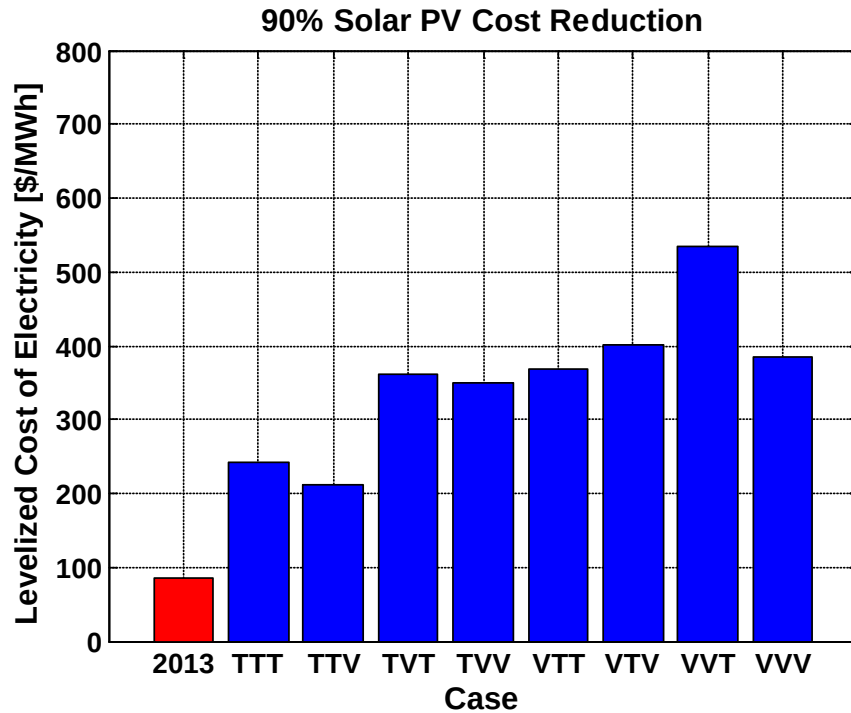


Figure 238 - Levelized Cost of Electricity for the 2050 Cases with 90% Solar PV Installed Capital Cost Reduction. Year 2013 included for comparison

Compared to current levels, even with reductions in solar PV cost, the levelized cost of electricity is still expected to increase. This is due to a number of factors including but not limited to:

- Increased load demand due to population and due to electrification of the transportation sector through BEVs or FCVs requiring higher capacities of generation resources compared to current levels.
- The installed cost of renewable resources and relatively lower capacity factors compared to conventional power plants
- The cost of energy storage to match load and generation profiles.

While decreasing the solar PV cost makes noticeable reductions in the CEPC, even with a 90% reduction in installed capital costs for the technology, the CEPC is still at least twice as much as current levels. In the “Vxx” cases which rely almost exclusively on solar PV, the CEPC increases from current levels by at least a factor of 2.81. Solar PV is a main contributor to the cost of electricity in all cases, since even the “Txx” cases rely heavily on 1-axis tracking solar PV, however, other contributors to the cost of electricity are also of similar magnitude. The breakdown of the percentage contribution to the total electricity cost by grid technology is presented in Figure 239 for 2013 solar PV costs, and in Figure 240 for 90% solar PV cost reductions.

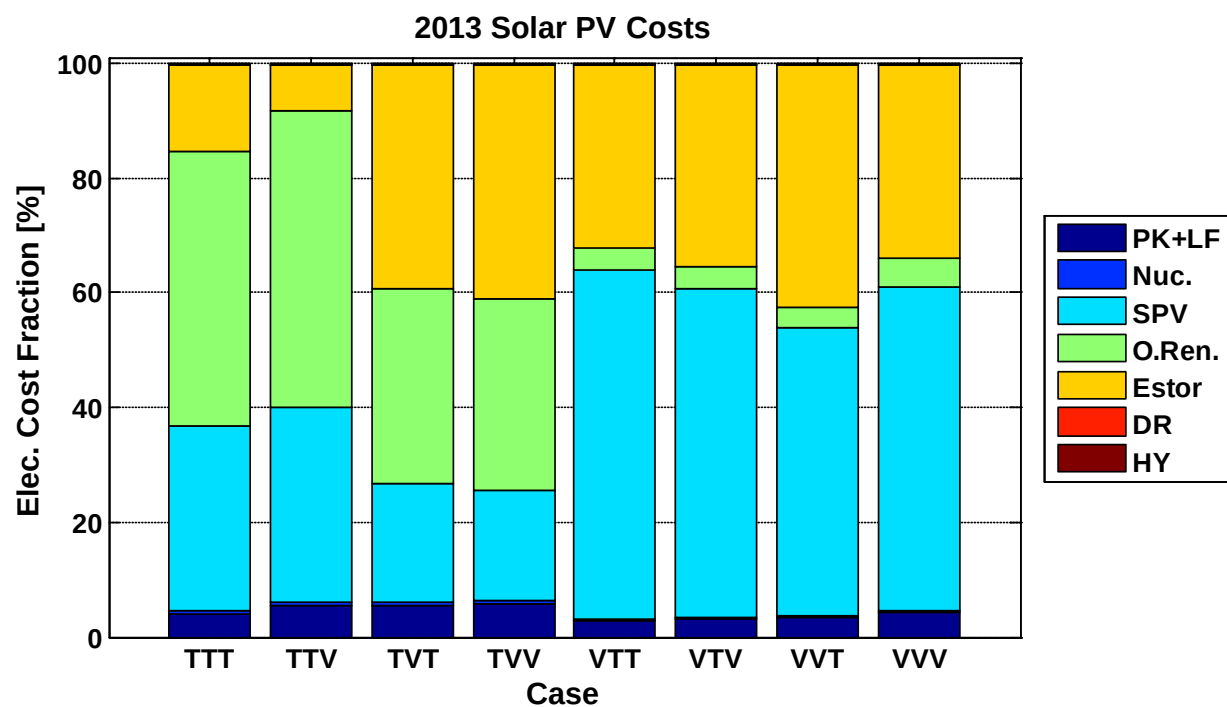


Figure 239 - Fractional Breakdown of Total Electricity Cost by Generation Resource Type using Year 2013 Solar PV Installed Capital Costs

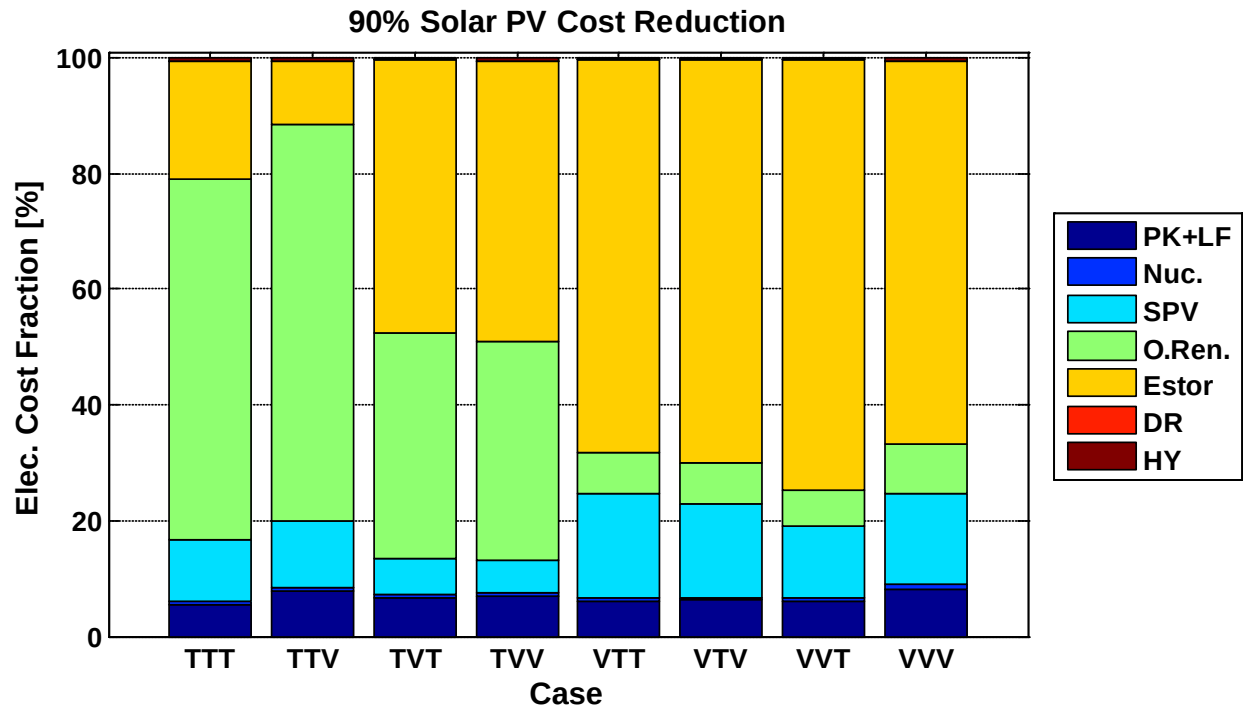


Figure 240 - Fractional Breakdown of Total Electricity Cost by Generation Resource Type using 90% Solar PV Installed Capital Cost Reduction

The breakdown includes the following components:

- Peakers and Load-Followers (PK+LF): Conventional, non-base load power plants providing reliability services and grid balancing. Includes biopower.
- Nuclear (Nuc): Base load nuclear power.
- Solar PV (SPV): Includes both fixed rooftop and 1-axis tracking PV. The latter includes transmission costs.
- Other Renewables (O.Ren): Renewables other than Solar PV. Includes Wind, Geothermal, and Solar Thermal
- Energy Storage (Estor): Energy storage systems.
- Demand Response (DR): Includes the cost of installing building demand response systems. Relevant only in the “Vxx” cases.

- Hydropower (HY): Includes both large and small hydropower.

With year 2013 Solar PV costs, solar PV contributes a sizeable but not dominant contribution to the cost of electricity in the “Txx” cases. This is expected since solar PV forms a smaller fraction of the renewable portfolio in these cases. The “TTx” cases are dominated by the expense on other renewable resources, whereas the “TVx” cases are dominated by energy storage costs. In the “Vxx” cases, solar PV is the dominant electricity cost contributor, however, energy storage costs are on similar magnitudes.

With a 90% reduction in solar PV costs, the fractional contribution of solar PV expectedly decreases. In the “TTx” cases, this leaves other renewables as the dominant contributor, and for all other cases, energy storage becomes the dominant contributor. This is especially pronounced in the “Vxx” cases due to the large amount of energy storage required.

Overall, the prevalence of energy storage costs highlights **the importance of evaluating system costs** when assessing the economic impacts of meeting greenhouse gas goals. The costs of renewable generation and its delivery are only a part of the entire picture: effects due to additional equipment needed to match generation with load in time, and operations of the electric grid can also play significant roles in electricity costs, and therefore the cost of energy per capita.

7.1.2.7.3. Vanadium Flow Battery (VFB) Cost Sensitivity:

The previous results show that in addition to the cost of renewable resources, the cost of energy storage is a significant contributor to the cost of electricity. Therefore, it is also important to examine the effect of reducing the installed capital cost of energy storage relative to current levels in conjunction with reducing solar PV costs. The cost of energy per capita for reductions

in VFB costs by 50% in conjunction with solar PV cost reductions of 50% and 90% are presented in Figure 241 and Figure 242, respectively.

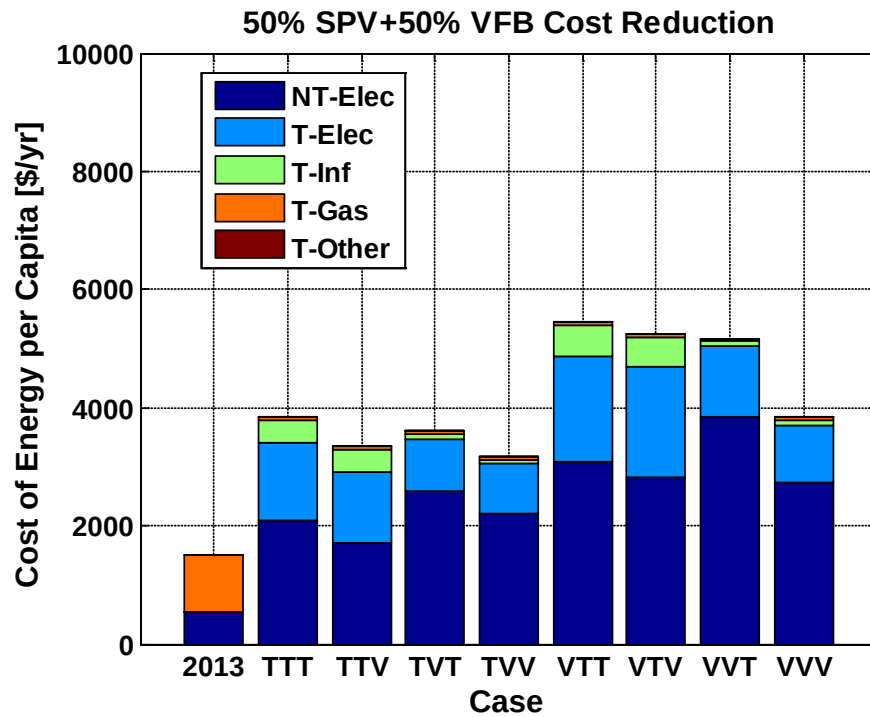


Figure 241 - Cost of Energy per Capita for the 2050 Cases with 50% Solar PV and 50% Vanadium Flow Battery Installed Capital Cost Reduction. Year 2013 included for comparison

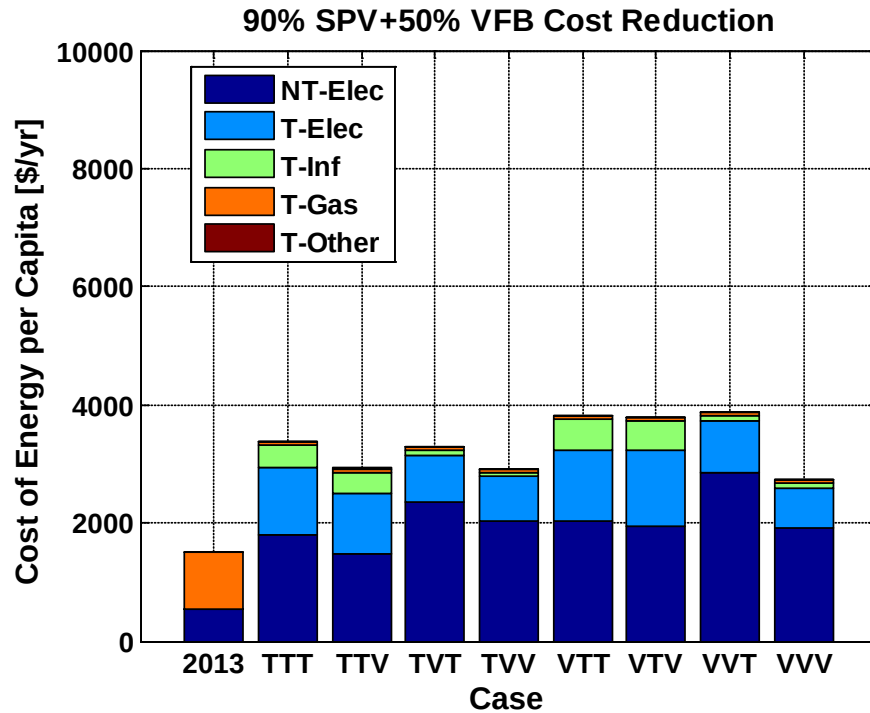


Figure 242 - Cost of Energy per Capita for the 2050 Cases with 50% Solar PV and 50% Vanadium Flow Battery Installed Capital Cost Reduction. Year 2013 included for comparison

The CEPC multiplier compared to current levels is reduced to between 2.13 and 3.51 for the 50% Solar PV / 50% VFB cost reduction case, and between 1.82 to 2.59 for the 90% Solar PV / 50% VFB cost reduction case. Note that for the 50% SPV / 50% VFB cost reduction case, the upper limit of the CEPC increase is lower than that for the 90% SPV cost reduction alone case. This is an indication of how the cost breakdown changes, and that the CEPC becomes more sensitive to different technologies as this breakdown changes. Even with solar PV and VFB cost reductions, however, the CEPC is still higher than current levels.

The relative CEPC levels between the different cases changes with reduction of energy storage costs in conjunction with that for solar PV costs. The “Vxx” cases exhibit CEPC levels that are much closer to that for the “Txx” cases, since solar PV and energy storage are the dominant contributors to costs in the “Vxx” cases. Previously, the TTV case exhibited the lowest CEPC

levels, since it combined relatively high capacity factor, low capital cost renewable resources which reduced required renewable capacity with dispatchable transportation loads and less peak-dominated renewable generation which minimized required energy storage capacities. By reducing the cost of energy storage, the flexibility of dispatchable loads which avoids energy storage costs becomes less important compared to the cost of the renewables and the magnitude of the load that must these resources must meet.

In the 50% SPV / 50% VFB cost reduction case, the VVV case reaches parity with the “Txx” cases since it has one of the lowest grid load energies. The TVV case has the lowest CEPC due to having the absolute lowest grid load energy.

In the 90% SPV / 50% VFB cost reduction case, the VVV case exhibits the lowest CEPC levels, since it relies more heavily on solar PV compared to the TVV case, and the cost of energy storage is no longer a dominant factor.

7.1.2.8. Cost per Mile

The cost of energy per capita characterizes the actual economic impact of installing and operating options to meet sustainability goals. Consumers, however, perceive energy costs in separate components, and tend to focus more on trends in the cost of one service versus that for the combined cost of all services. This is an important point to consider regarding social acceptance of implementing technologies in individual sectors. The primary services encompassed in the cost of energy per capita in this analysis are for electricity and transportation. The levelized cost of electricity was presented in the description of the CEPC results. The cost of transportation per mile for the 2050 cases using 2013 solar PV costs is presented in Figure 243. The cost of transportation per mile was calculated by adding up all of the costs directly

associated with providing transportation fuel, including feedstock and non-feedstock related costs, and dividing by the annual vehicle-miles-traveled for the state. The cost per mile for 2013, which encompasses gasoline only, is included for comparison.

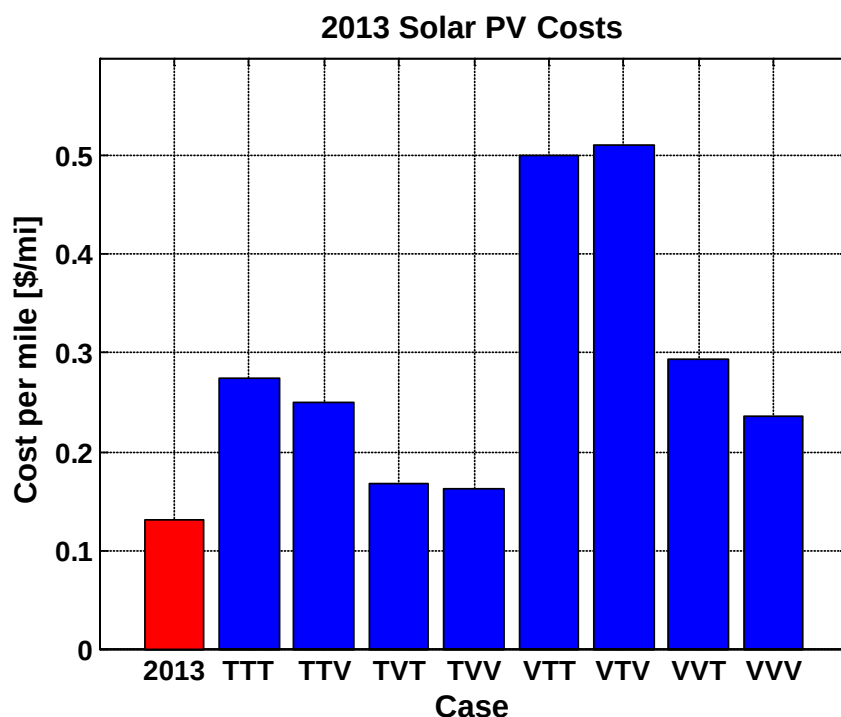


Figure 243 - Cost per Mile of Light-Duty Transportation for the 2050 Cases, using Year 2013 Solar PV Costs. Year 2013 Levels included for comparison

In contrast to the levelized cost of electricity, which is increased by a large amount for all of the 2050 cases, the cost per mile is close to parity with current levels for some of the cases. The “xVx” cases which rely on BEVs tend to have lower costs per mile compared to the “xTx” cases which rely on FCVs. When considering the transportation-related costs only, this is expected. BEVs have lower infrastructure costs compared to FCVs, since charging BEVs requires mainly an upgrade and expansion of already-existing electric infrastructure in the state. FCVs, on the other hand, require the installation of all-new infrastructure for production, delivery, and distribution. More importantly than the infrastructure costs, however, are the feedstock costs, as

evidenced by the CEPC results. BEVs also have an advantage in this case, since the electric load due to BEVs is lower than that compared to FCVs when the latter is heavily dependent on electrolysis. These factors combined allow the BEVs to have lower costs per mile compared to FCVs, considering the transportation sector alone. The dispatchability of the hydrogen electrolysis load reduces the cost of electricity, which reduces the non-transportation electricity cost to compensate in the CEPC. With 2013 solar PV costs, the TVT and TVV cases which have relatively low electricity costs and rely on BEVs reach near-parity with current levels, exhibiting cost per mile figures that are 1.23x and 1.27x that of year 2013 levels. The lowest-cost FCV-reliant case is the TTV case, which exhibits a cost per mile that is 1.90x that of current levels.

The reduction of solar PV costs affects the cost per mile by reducing the levelized cost of electricity, therefore reducing the electricity feedstock cost of the transportation sector. The cost per mile of transportation for the 50%, 75%, and 90% solar PV cost reduction scenarios is presented in Figure 244, Figure 245, and Figure 246, respectively:

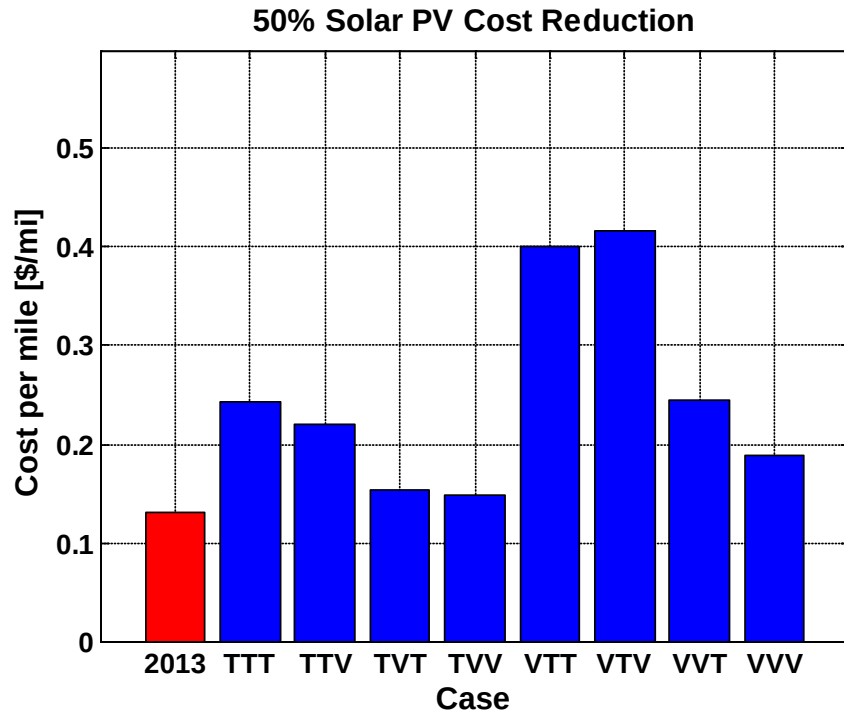


Figure 244 - Cost per Mile of Light-Duty Transportation for the 2050 Cases, using a 50% Solar PV Capital Cost Reduction. Year 2013 Levels included for comparison

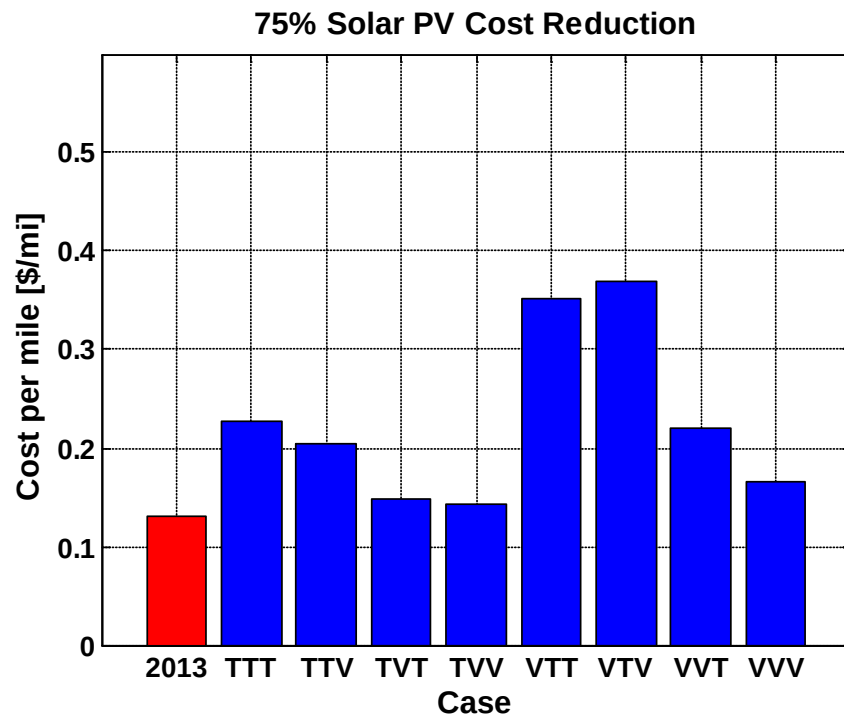


Figure 245 - Cost per Mile of Light-Duty Transportation for the 2050 Cases, using a 75% Solar PV Capital Cost Reduction. Year 2013 Levels included for comparison

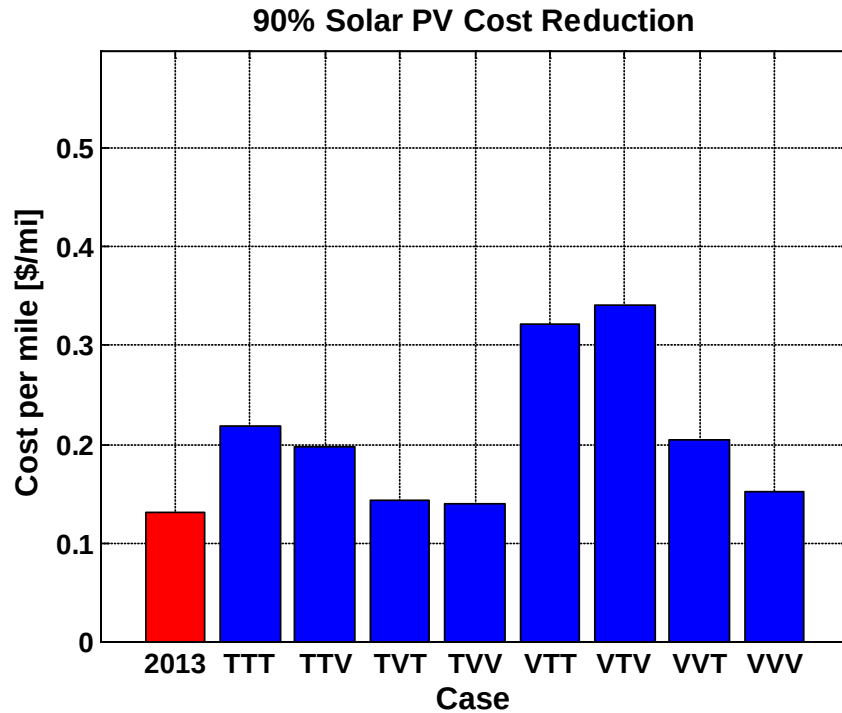


Figure 246 - Cost per Mile of Light-Duty Transportation for the 2050 Cases, using a 90% Solar PV Capital Cost Reduction. Year 2013 Levels included for comparison

Expectedly, the cost of transportation per mile is reduced further. With a 75% reduction in solar PV costs, three cases reach near-parity with current levels. The TVT, TVV, and VVV cases exhibit cost per miles figures that are 1.12x, 1.09x, and 1.26x that of current levels. The lowest-cost FCV case remains the TTV case, which is 1.56x current levels. By the 90% solar PV cost reduction case, these figures improve to 1.09x, 1.06x, and 1.15x respectively, and to 1.49x for the lowest-cost FCV case.

The reduction of energy storage costs also reduces the levelized cost of electricity and therefore the electricity feedstock cost of the transportation sector. The cost per mile for the 2050 cases with a 50% solar PV / 50% VFB and a 90% solar PV / 50% VFB case is presented in Figure 247 and Figure 248, respectively.

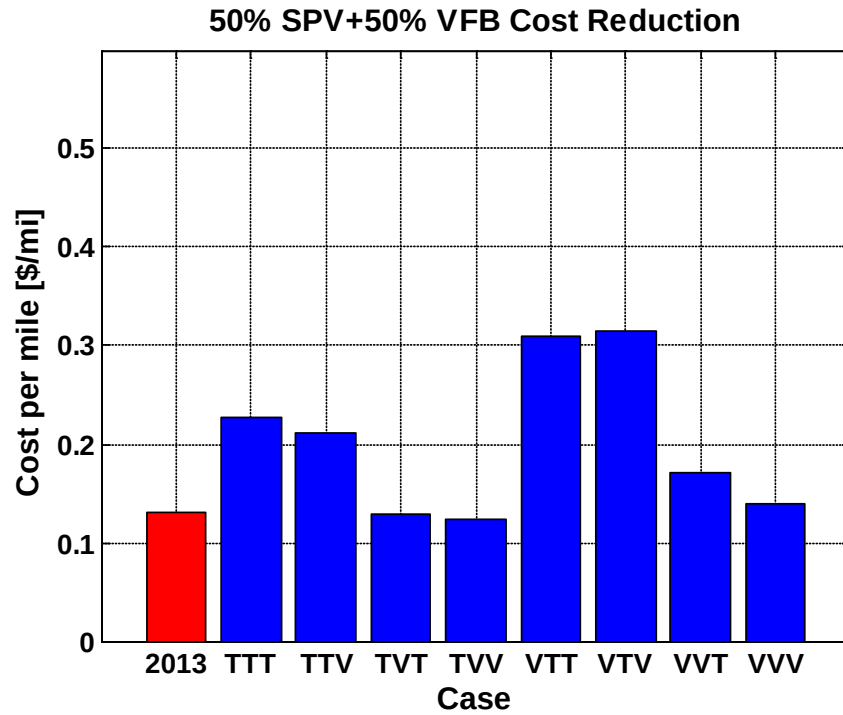


Figure 247 - Cost per Mile of Light-Duty Transportation for the 2050 Cases, using a 50% Solar PV and 50% Vanadium Flow Battery Capital Cost Reduction. Year 2013 Levels included for comparison

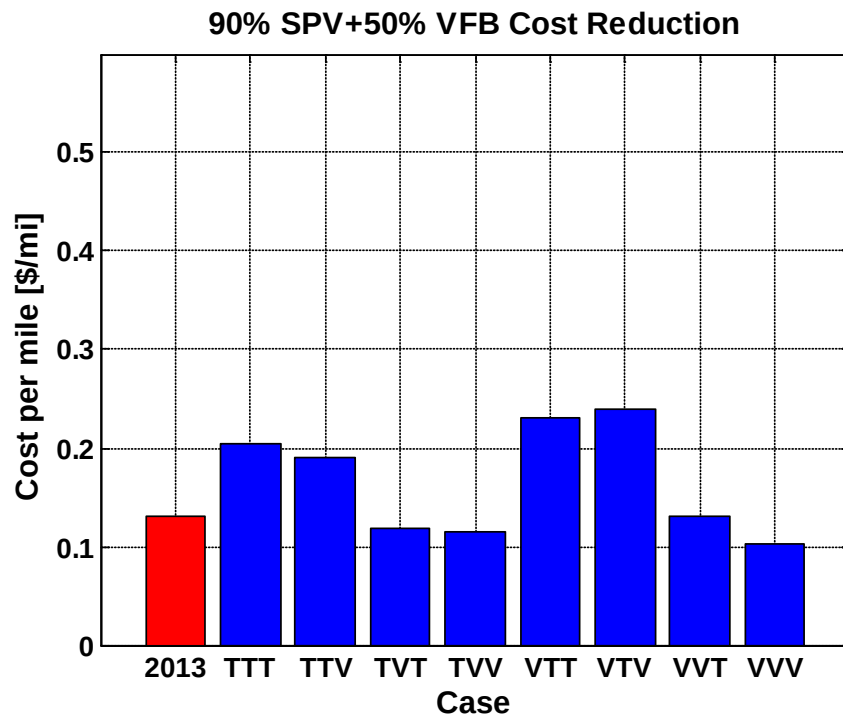


Figure 248 - Cost per Mile of Light-Duty Transportation for the 2050 Cases, using a 90% Solar PV and 50% Vanadium Flow Battery Capital Cost Reduction. Year 2013 Levels included for comparison

In these scenarios, certain 2050 cases actually exhibit lower costs per mile of transportation compared to current levels. For the 50% solar PV / 50% VFB cost reduction, the TVT, TVV, and VVV cases again exhibit the lowest cost per mile figures of 0.97x, 0.94x, and 1.06x of current levels. The lowest-cost FCV case is the TTV case, at 1.61x that of current levels. With a 90% solar PV / 50% VFB cost reduction scenario, the TVT, TVV, and TTV cases exhibit cost per mile figures of 0.90x, 0.87x, and 0.78x that of current levels. The reduced cost of electricity in the “Vxx” cases relative to the other two allows the VVV case to exhibit the lowest cost per mile figures. In this scenario, all of the cases which rely on BEVs have lower cost-per-mile figures compared to current levels. The lowest-cost FCV case is again the TTV case, which exhibits a cost per mile of 1.44x that of current levels.

Overall, when considering the transportation sector alone, BEVs tend to have an advantage over FCVs due to lower infrastructure costs and lower electric loads. This may be a selling point in the eyes of the consumer for this technology when viewing the transportation sector alone. This does not necessarily translate into BEV-reliant cases having lower holistic energy costs than FCV-reliant cases, as shown by the results of the cost of energy per capita. This result also shows the importance of considering holistic metrics when examining the economic impact of deploying sustainability-oriented technologies in co-dependent resource sectors. Viewing the performance of holistic combination of sectors can show very different results than that implied by viewing individual sectors in isolation.

7.1.3. Summary and Conclusions

This part of the study examined the advantages and disadvantages from technical and economic standpoints for simultaneously meeting the sustainability goals of reducing greenhouse gas emissions and securing the water supply in California, based on consumer-transparent or

consumer-visible evolution paradigms for the electricity, transportation, and water supply sectors. The primary findings are summarized as follows:

1. Using centralized generation requires less renewable capacity and energy storage to meet the 2050 greenhouse gas emissions reduction goal. This occurs due to the following reasons:

- a. Relying on centralized renewables allows the use of a more diverse portfolio of renewable resources which have higher capacity factors compared to distributed renewables. This allows more energy to be obtained for a given installed capacity level.
- b. Centralized renewables exhibit temporal profiles which are more complementary to each other, smoothing out the total renewable generation profile and allowing it to coincide more with the profile of the raw load demand. Therefore, the amount of energy that must be shifted to allow load and generation profiles to coincide is also reduced.
- c. Centralized balancing generation is more efficient than distributed balancing generation, and therefore can provide generation associated with grid reliability services while emitting less greenhouse gases.

2. The dispatchability of the electric load is important for allowing the system to avoid the need for excessive energy storage capacity.

- a. The use of hydrogen fuel cell vehicles imposes a larger load on the electric grid compared to battery electric vehicles. The increased dispatchability of this load due to its centralized nature and decoupling from consumer behavior, however,

allows it to perform a significant amount of the load-shifting functions needed to utilize renewable energy. This reduces the required capacity of energy storage which would otherwise be needed to perform these functions.

3. Aggressive renewable portfolio standard goals are required to meet the 2050

greenhouse gas emissions reduction goals. The carbon intensity of the electric grid is a critical determining factor being able to meet greenhouse gas emissions goals.

- a. The stationary electric load will increase along with the vehicle-miles-traveled demand of an increasingly electrified transportation sector. Additionally, many water supply stabilization measures rely on electric energy. These compounding trends cause the carbon intensity of the electric grid to be a central determinant of the system's ability to meet greenhouse gas emissions reduction goals.

4. The energy impact of securing the surface water reservoir levels is relatively small compared to that of meeting the stationary and transportation-related load demands.

- a. Even in the "xxT" cases which rely heavily on large capacities of desalination, the energy of the load imposed on the grid due to water supply measures is only about 7.3% of the total load demand. This occurs due to the offsets in the loads due to the conveyance of water in California.
- b. The "xxV" cases show are able to secure the surface water reservoir levels with essentially negligible impacts on the energy of the electric load demand.

- 5. The change in water consumption levels due to shifts in the electric grid resource mix is not trivial, but small compared to projected changes in the urban and agricultural consumption levels.**
- a. The “Vxx” cases rely on renewable resources with little to no water consumption to offset conventional power plant capacity.
 - b. The “Txx” cases rely mostly on low-water intensity renewable resources, with the exception of solar thermal power plants. The strong reliance on solar thermal power plants causes the water consumption to increase slightly.
- 6. The change in the in-operation water consumption due to shifts in the transportation mix is small due to reductions in the water consumption for producing gasoline.**
- a. In operation, electric vehicles only have water impacts through loads imposed on the grid.
 - b. Fuel cell vehicles have water impacts by requiring feedwater for electrolysis and steam methane reformation processes, but this is small relative to the water consumption for producing gasoline.
- 7. System or balance-of-plant costs must be considered to understand the cost impacts of meeting sustainability goals.**
- a. Reducing the cost of solar PV only shifted the dominant cost contributor to energy storage, which is significant in cases that require a high capacity.

8. Reliance on fuel cell vehicles with flexible electrolysis loads provides increased load dispatchability at the expense of an increased electric load energy compared to battery electric vehicles.

The economic value of this dispatchability depends on the levelized cost of electricity and energy storage costs.

- a. If electricity is very expensive relative to energy storage costs, the cost of meeting the increased load demand offsets the savings due to reducing energy storage costs.
- b. If electricity is not very expensive relative to energy storage costs, reducing energy storage costs more than compensates for the cost of meeting an increased load demand.
- c. Reliance on fuel cell vehicles causes consumers to pay less for electricity, but more for transportation compared to reliance on battery electric vehicles.

9. The economic motivation for relying on fuel cell vehicles depends heavily on the ability to dispatch the electrolysis load.

- a. The primary benefits of relying on fuel cell vehicles are based on its increased flexibility relative to that of the battery electric vehicle charging load.
- b. If the electrolysis load cannot be dispatched to be more flexible than the battery electric vehicle charging load, then battery electric vehicles have a clear advantage.

10. The cost of transportation fueling infrastructure is small compared to the costs associated with feedstocks used to produce transportation fuel.

- a. The transportation-related electricity cost far outweighed the cost of charging infrastructure or hydrogen supply infrastructure.
- b. Changes that affect the feedstock cost can more than compensate for differences in the cost of the fueling infrastructure alone.

11. Without significant reductions in the cost of distributed renewables and energy storage, utilizing a centralized electric generation paradigm allows more economical satisfaction of the sustainability goals when considering the holistic cost of energy.

- a. The lack of diversity in the available low-carbon portfolio for distributed generation forces a stronger reliance on fixed rooftop solar PV, giving rise to an extremely peak-dominated renewable generation profile, requiring a significant amount of energy storage to compensate.
- b. Reductions in both solar PV and energy storage costs are needed for a visible electricity sector paradigm to be on par with a transparent paradigm in terms of the holistic cost of energy.

Based on these findings, the following are the recommendations for the preferred paradigms for the evolution of the electricity, transportation, and water supply sectors:

- **Electricity: Consumer-Transparent is preferable.**
 - o Lower capital cost of renewables
 - o Diverse renewable mix allows more coincidence between generation and load profiles, reducing energy storage requirements
 - o Higher capacity factors reduce the required capacity to meet sustainability goals.

- o Centralized generation provides grid reliability services with lower greenhouse gas emissions.
- Transportation: **Depends on electrolysis load dispatchability.**
 - o If electrolysis load is more flexible than BEV charging load: **Consumer-Transparent (FCV) is preferable.**
 - o If electrolysis load is not more flexible than BEV charging load: **Consumer-Visible (BEV) is preferable.**
- Water Supply: **Consumer-Visible is preferable.**
 - o The low energy intensity and the offsets in the energy needed for the conveyance of water in California allows securing the water supply to have little to no impact on the ability to meet sustainability goals in the visible paradigm cases.

The best performing cases all-around are the **TTV and TVV** cases, from the perspectives of cost of energy per capita, renewable capacity, and required energy storage capacity based on this study. While some sensitivity to this result has been examined, there are also other factors which could change this recommendation. This will be discussed in the following section.

7.1.4. Additional Sensitivity Considerations and Recommendations

This analysis considered many interactions and factors that affect the performance of different pathways to meet emissions and water-related sustainability goals. There are many additional factors, however, that can affect the recommendation of this study by either strengthening the

case for the sector paradigm preferences or reversing them. Some of these factors are briefly discussed here.

The Cost of Water Supply Measures. In terms of costs, this study considered the holistic cost of energy per capita, which measured the economic impact of providing energy-related services such as electricity and transportation. While the operational impact of water supply measures on the combined system have been considered, especially with respect to energy, the cost of implementing the measures associated with the option portfolios which stabilized water reservoir levels were not assessed. The cost of providing water associated with these measures could influence the economic performance of the different cases. In this case, this refers to comparing the costs of a desalination heavy case (Transparent) versus a case with a more diverse water supply portfolio (Visible). Opportunities for future work include development of a method for determining the levelized cost of water for the considered water supply measures which is sensitive to the operational interactions of these measures with the other resource sectors. **This would allow the determination of a holistic cost of utility, which would more directly indicate the effect of deploying these portfolios to meet sustainability goals.**

Regional Water Availability for Solar Thermal Power Plants. This study considered the effect of shifts in the grid resource mix on water consumption and reservoir levels in the statewide scope. While the effect was relatively small compared to changes in urban and agricultural water demands and therefore on reservoir levels, this assumes that allocations from the Sacramento Delta that are freed up by implementing these measures are available to be used by all power plant types. Logistically, this may not be the case for solar thermal power plants in California, which are located in the southeastern desert of the state. Much of the water supply in

the region is sourced from groundwater, and surface water allocations are not extensively available to be conveyed to this region. Developing the overdraft of groundwater may occur which would cause an undesirable environmental impact. Lack of water availability in this region can limit the installation of these power plants and force reliance on either more tracking solar PV or distributed solar PV in the consumer-transparent electricity paradigm case. This can change its cost profile as well as its operational profile, affecting its performance **and potentially forcing a consumer-visible electricity paradigm preference.**

Social Resistance to Transmission Corridor Construction. One of the major motivations for shifting towards a distributed generation paradigm is the difficulty of siting, permitting, and constructing additional transmission lines. Most of the centralized wind and solar resources are located in the southeastern desert regions of the state, where transmission infrastructure is less dense. Therefore, additional transmission lines will be needed to connect these resources to the electric grid so they can be utilized to serve load. Historically, however, there has been significant difficulty with securing the right-of-way for additional transmission corridors due to social resistance. Many residents do not want high voltage transmission lines running through or near their towns. The legal battles regarding these situations can force transmission lines to take roundabout paths, significantly delay utilization of available renewable resources, or prohibit these lines from being installed altogether. This can also cause costs to escalate. While transmission costs were taken into account in this study, these costs were assumed to be under standard conditions. If social resistance to transmission corridor construction becomes a prohibitive obstacle, utilizing centralized resources may be difficult or altogether not possible. **This could reverse the electricity paradigm preference from consumer-transparent to consumer-visible.**

The Cost of Alternative Fuel Vehicles. This analysis takes into account all of the cost components associated with providing the energy needed to fuel transportation needs. The cost that the consumer will actually pay to meet their transportation needs, however, is also heavily dependent on the cost of the vehicles themselves. This analysis does not take into account the cost of the actual fuel cell vehicles or battery electric vehicles. This comparison is currently difficult to determine for future years, since it will depend on the costs to produce these vehicles, which are proprietary and known only by the automobile manufacturers. This cost is important nonetheless. If FCVs are significantly more expensive than BEVs, then the penetration of FCVs into the market will be limited and BEVs will be preferred. The reverse occurs for the opposite scenario. Once vehicles of both types have been released on the market, it may be possible to obtain a more accurate picture of the economic performance of scenarios that rely on one vehicle type or another.

Distribution of Investment in Transportation Infrastructure. This analysis treats the FCV and BEV fueling infrastructure and feedstock costs as if these infrastructures have already reached their designated market penetration. In reaching that market penetration from current times, however, FCVs and BEVs have inverse issues when it comes to an implementation and growth standpoint. BEVs are easier to initiate deployment, since it requires low up-front investment due to infrastructure requirements being an upgrade of already existing infrastructure, but may be more costly in the long term due to the lack of dispatchability causing increases in feedstock costs. FCVs on the other hand, may be cheaper in the long term due to the benefits of electric load dispatchability, but requires significant up-front investment due to the need to construct new infrastructure. If this initial investment hurdle is unable to be overcome due to its magnitude or risks, however, then FCVs will not reach the point where the hydrogen

infrastructure can be built-out to provide the benefits of dispatchability. **This would force a consumer-visible paradigm reliant on BEVs for the transportation sector.**

Operational Scheduling of Transportation-Related Electric Loads into the Grid. In the consumer-visible transportation paradigm reliant on BEVs, it is assumed that consumers are willing to schedule their vehicle to provide services to the electric grid ahead of time, and that these schedules are adhered to 100% of the time. In practice, this may not be feasible in the following ways:

- Consumers may not be able to commit their vehicles for grid-use ahead of time.
- Consumers may not be able to adhere to their proposed schedule.
- Consumers may not be willing to allow grid-control of a resource that they own.

In the event of the first two occurrences, this would diminish the extent to which BEV charging dispatch can aid grid operations such as utilizing curtailed renewable generation or smoothing the net load profile. Due to the manner in which the electricity markets operate, most resources are scheduled in the day-ahead market. If electric vehicles are only able to commit services on short-notice in the real-time market, it won't affect the dispatch and scheduling of other resources and their impact will be reduced. Additionally, if there is uncertainty the amount of services that can be counted on by these vehicles, grid operators may plan for minimal impact out of reliability concerns and the full potential benefit of utilizing these vehicles will not be realized. In the event of the third occurrence, the electric vehicle charging load will be static and unable to provide any intentional benefit to managing the grid, which may be detrimental to case performance in the context of utilizing high capacities of variable renewables. If the realizable portion of the potential of BEV services to the grid is diminished to too much of an extent due to

these factors, then BEVs may not make as much of a real-world impact as FCVs, whose loads are easy to schedule and plan on ahead of time in the real system. **This would cause a preference for the consumer-transparent (FCV) transportation paradigm.** Future studies need to characterize the effect of scheduling and grid management requirements on the realizable potential of BEV and FCV services to the grid.

Overall, there are many considerations that may affect what will be the preferred evolution of major resource sectors for simultaneously meeting holistic sustainability goals. Future studies may be able to address some of these issues, and update these results to provide a more accurate picture of the best path forward. These are promising subjects for future research.

Chapter 8: Summary of Conclusions

This dissertation utilized a number of different individual analyses to carry out its main task of advising the deployment of sustainability-oriented technology and management options in the combined electricity, transportation, and water supply sector. For reference, a summary of the conclusions for each of the individual analyses is stated here. The details of each conclusion can be found in the conclusions section of the respective study.

8.1. Individual Resource Sector – Electricity

8.1.1. Renewable Resources

1. Significant benefits for grid performance can be obtained by diversifying the renewable portfolio.
2. Additional measures must be taken to avoid the onset of renewable curtailment.
3. Regional resources give rise to better grid performance compared to locally-sited resources.
4. Balancing generators will need increased dynamic capabilities to accommodate renewable generation behavior.

8.1.2. Energy Storage

1. Energy storage can improve system performance in many aspects, but certain benefits require overcoming of the energy penalty for using the system to be realized.
2. Selection of the power and energy storage capacity of the system is important.
3. The cost-competitiveness of energy storage is a tradeoff between the economic benefit of improving system performance and the capital, operation and maintenance costs, and the costs associated with the energy storage penalty.

4. The incremental benefits of implementing energy storage can start to diminish as the system size increases.

8.1.3. Demand Response

1. The preferred strategy for using demand response will change with renewable penetration and depends on which performance aspect is desired to be improved.
2. Different operating strategies should be employed for DR as the renewable penetration changes to maximize economic value.

8.2. Individual Resource Sector – Water Supply

1. Under baseline conditions, many of the available options are able to stabilize or nearly stabilize surface reservoir levels in isolation.
2. Under climate change augment conditions, including changes in inflow and increases in demand, a portfolio approach of measures will be required to stabilize surface reservoir levels.
3. Deploying both water reuse along with conservation is not additive in terms of stabilizing reservoir levels, since conservation may reduce the potential capacity for water reuse.
4. The steady-state nature of desalination plants allows a large potential for reducing groundwater demand.
5. Coordinated management practices and policies are required to most effectively stabilize the water supply.
6. Finding points of leverage in the system are important for maximizing the effectiveness of deploying a given option.

8.3. Paired Resource Sectors – Electricity and Transportation

8.3.1. Plug-in Hybrid Electric Vehicles and Renewable Resources

1. The integration of PHEVs with smart charging can increase the utilization of installed renewable resources, but only under certain conditions.
2. The electrification of the light-duty transportation sector through the use of PHEVs can contribute to reductions in combined sector fuel usage and GHG emissions, but the extent of these benefits depends on the progress of the grid towards reaching renewable energy procurement goals.
3. In the holistic scope, environmental benefits due to the use of PHEVs are maximized when synergies between the deployment of these vehicles and that of renewable power generation are considered.
4. The integration of PHEVs with smart charging can counteract many of the operational problems that variable renewable power has on the electric grid, but becomes limited in its ability to do so at high renewable penetration levels due to load size and flexibility constraints.
5. The design and operational benefits of PHEVs provide cost savings for the electricity sector, but these savings will need to be weighed against the cost of installing the infrastructure necessary to provide such benefits.
6. The use of smart charging is important for providing benefits for the design and operation of load-balancing resources on the electric grid.

8.3.2. Battery Electric Vehicles, Fuel Cell Vehicles and Renewable Resources

1. The GHG reduction potential of BEVs and FCVs are similar under careful infrastructure planning. This occurs since the increased dispatchability of the hydrogen electrolysis load

compared to the BEV charging load allows the system to more effectively match generation and load profiles, making use of renewable generation that would otherwise be curtailed, offsetting the increased energy demand if the electrolysis fraction is sized appropriately.

2. FCV deployment exhibits slightly increased costs of energy per capita compared to BEVs under careful infrastructure planning. The increased dispatchability of the hydrogen electrolysis load has economic value in reducing curtailed energy and smoothing the operation of balancing generators. These effects do not completely offset the increased infrastructure costs of FCVs compared to BEVs, but they still significantly reduce the cost of energy per capita gap between the two technologies in the integrated system.

8.4. Paired Resource Sectors – Electricity and Water Supply

1. Greenhouse gas emissions increase due to reduced hydropower generation under climate change augmented conditions.
2. Emissions effects due to systematic impacts of implementing options must be taken into account.
3. Reservoir levels may be secured with beneficial or neutral effects on greenhouse gas emissions if the portfolio of water supply stabilizing options is chosen carefully.
4. Stabilizing surface reservoir levels can either be detrimental or beneficial for progress towards satisfying renewable portfolio standard goals, depending on portfolio composition.

8.5. Combined Trisector System – Electricity, Transportation, and Water Supply.

1. Using centralized generation requires less renewable capacity and energy storage to meet the 2050 greenhouse gas emissions reduction goal.
2. The dispatchability of the electric load is important for allowing the system to avoid the need for excessive energy storage capacity.
3. Aggressive renewable portfolio standard goals are required to meet the 2050 greenhouse gas emissions reduction goals. The carbon intensity of the electric grid is a critical determining factor being able to meet greenhouse gas emissions goals.
4. The energy impact of securing the surface water reservoir levels is relatively small compared to that of meeting the stationary and transportation-related load demands.
5. The change in water consumption levels due to shifts in the electric grid resource mix is not trivial, but small compared to projected changes in the urban and agricultural consumption levels.
6. The change in the in-operation water consumption due to shifts in the transportation mix is small due to reductions in the water consumption for producing gasoline.
7. System or balance-of-plant costs must be considered to understand the cost impacts of meeting sustainability goals.
8. Reliance on fuel cell vehicles with flexible electrolysis loads provides increased load dispatchability at the expense of an increased electric load energy compared to battery electric vehicles. The economic value of this dispatchability depends on the levelized cost of electricity and energy storage costs.
9. The economic motivation for relying on fuel cell vehicles depends heavily on the ability to dispatch the electrolysis load.

10. The cost of transportation fueling infrastructure is small compared to the costs associated with feedstocks used to produce transportation fuel.
11. Without significant reductions in the cost of distributed renewables and energy storage, utilizing a centralized electric generation paradigm allows more economical satisfaction of the sustainability goals when considering the holistic cost of energy.

Chapter 9: Overall Recommendations and Future Work

The overall analysis of this dissertation focused on characterizing the technical and economic performance of different technology and management options in different resource sectors with respect towards satisfying sustainability goals. These technologies were examined in the contexts of individual resource sectors and for the combined electricity-water, electricity-transportation, and electricity-transportation-water supply system, dynamically taking into account their impacts on co-dependent infrastructures and their interactions with other options. While this analysis has considered and taken into account many aspects that have not been included to the same level of detail in previous analyses, there are also many other aspects which were not considered here but are nonetheless very important for conducting a comprehensive holistic sustainability analysis. Inclusion of some of these aspects is topics for future work, and the topics themselves are outlined in brief as follows:

- **Incorporating dynamic modeling of the transmission and distribution systems.** The model in this analysis did not model specific aspects of the power delivery system in any of the cases considered. Important aspects regarding the implementation of the considered technologies include but are not limited to power flow patterns on the transmission system, transmission line capacities, and management of power flow between and within microgrids. Future analyses need to incorporate this level of detail to further assess the performance of the different individual options and option portfolios.
- **Incorporating load / generation forecasting.** The data used in the model for this analysis assumed that electric grid operators have a very accurate forecast of renewable generation and load demand over the planning horizon. In practice, this may not be the case, as forecasts often have errors and therefore affect the dispatch of available

resources. Future analyses may need to incorporate real-time forecasting models to drive the dispatch of available resources and determine the sensitivity of technology performance to the forecasting error.

- **Considering the cost of water stabilization measures.** The economic studies conducted in this dissertation considered the costs of electricity and transportation fuel to form a holistic cost of energy per capita. Water supply measures, however, may impact the economic viability of different scenarios for meeting the sustainability goals. Future analyses should develop and incorporate a generalized cost of water supply module which can calculate the cost of water due to shifts in the water supply portfolio to obtain a more complete picture of the economic impact of meeting sustainability goals.
- **Characterizing the life-cycle sustainability performance of different options.** The UCI-STREET model in its current form focuses primarily on in-operation sensitivities to technology and management option deployment in different resource sectors, with only some consideration of upstream impacts primarily for emissions purposes. To conduct a more complete picture of the sustainability performance of different options, however, life cycle performance must be considered. This includes evaluating the pre-operation and disposal phases of technology deployment in addition to the in-operation phases. Metrics to consider involve raw materials supply requirements, emissions and energy use due to extraction, transport, manufacturing, and safe disposal processes. The addition of this dimension of analysis can shed further insight into the synergies and interferences between different option deployment portfolios and can be used to further refine preferred deployment paradigms for satisfying sustainability goals.

- **Inclusion of groundwater reservoirs in the water supply infrastructure model.** The ability of different options to secure the water supply was measured by the ability to maintain surface reservoir levels. The implications for displacement of groundwater demand was examined, however, modeling of groundwater availability in different regions was not examined explicitly. In many regions of the state, groundwater is an important resource for water supply and is used heavily during drought periods in arid regions. Characterizing and including groundwater reservoirs in each region will help to give a more comprehensive picture of the effectiveness and scale of water supply stabilization measures needed to secure the water supply.
- **Characterizing the true flexibility of distribution-side energy resources.** Some of the technologies deployed in the analyses presented here are resources which will be installed and likely operated on the distribution system. This analysis assumed that these resources would be controlled by utilities or balancing authorities, and were amenable to responding to the needs of the bulk electric grid. In practice, this may not be the case, especially if these resources are installed by communities to meet community needs. Development and inclusion of a dynamic microgrid model into the larger electric grid model would provide insight into how to manage distributed energy resources and the degree of grid-responsive flexibility that is required to maximize sustainability benefits.
- **Characterizing the air quality impacts of different options.** The analyses in this dissertation focused strongly on greenhouse gas emissions, securing the energy supply, and securing the water supply. Reducing air pollution, as outlined in the introduction to this dissertation, is an important sustainability goal. Characterizing the air pollution impacts of implementing different technologies includes not just determining criteria

pollutant emissions, but dynamic linkage with detailed, spatially resolved air quality models and indicators for human health. This provides an additional criterion by which to evaluate the performance of different option portfolios.

- **Addition of the food/agriculture resource sector into the modeling platform.** This dissertation simultaneously considered three co-dependent resource sectors as the system for meeting sustainability goals: electricity, transportation, and water supply. Sustainability of the food/agriculture sector, however, is also an important issue since the provision of food is required for societal function. Adding a detailed characterization of the food/agriculture resource sector and emerging options into the combined modeling platform could further empower the model's capabilities for advising the deployment of options to meet sustainability goals.
- **Adding consideration of the heavy-duty transportation needs.** This dissertation focuses exclusively on the light-duty transportation sector, which is responsible for most of the transportation-related emissions and has the most diverse set of technology options. The heavy-duty transportation sector, however, still comprises a significant portion of total emissions, especially criteria pollutant emissions. This sector also has a different set of technology options available for use. Adding consideration of heavy-duty transportation can serve to provide a more complete picture of transportation-related sustainability.

These elements do not encompass all of the potential additions that can be implemented to create a more complete platform for holistic sustainability analyses, however, they represent a strong foundation for the development of this concept to provide more sound advice for the deployment

of options to meet sustainability goals for the combined system of all resource sectors that are key for societal function.

Chapter 10: References

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