A TECHNO-ECONOMIC ANALYSIS TO DETERMINE THE LEVELIZED COST OF HYDROGEN GENERATION THROUGH ELECTROLYSIS FOR HUMBOLDT TRANSIT AUTHORITY, HUMBOLDT COUNTY, CALIFORNIA

By

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ABSTRACT

A TECHNO-ECONOMIC ANALYSIS TO DETERMINE THE LEVELIZED COST OF HYDROGEN GENERATION THROUGH ELECTROLYSIS FOR HUMBOLDT TRANSIT AUTHORITY, HUMBOLDT COUNTY, CALIFORNIA

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This thesis aims to investigate the techno-economic feasibility of on-site electrolysis-based hydrogen generation for the Humboldt Transit Authority (HTA), focusing on determining the levelized cost of hydrogen (LCOH) for various system configurations and utility rate schedules. The study recommends using a 2.5 MW electrolyzer with the B-20 (T) utility rate schedule along with an E-GT rate supplement provided by PG&E as the most cost-effective solution to meet HTA's projected hydrogen demand. This demand is currently based on the utilization of 11 H_2 fuel cell buses, which is further expected to grow to 21 buses, and estimated public use at a hydrogen fueling station. The LCOH for this configuration is $6.08 per kg of hydrogen over the electrolyzer's 15-year (discounted by 5%) lifetime. By switching to on-site hydrogen generation, HTA can save around $6 million over the next 15 years compared to purchasing hydrogen from a commercial source at $7 to $9 per kg. Installing and operating a 1MW solar PV and 500kW & 1MWh battery energy storage system, and B-20 & E-GT rate supplement will result in a LCOH of $6.61 per kg of hydrogen. However, if the capital cost of the solar and battery energy storage is incentivized

through state and federal incentives, the LCOH can be brought down to $5.73 per kg of hydrogen (with 100% capex incentives).

The cost of purchasing a new 2.5 MW electrolyzer is approximately $3.7 million. When using the B-20 rate structure to produce electrolytic hydrogen, it is recommended to oversize the electrolyzer to achieve a 75% utilization rate, as this results in the lowest levelized cost of hydrogen (LCOH). A utilization rate of 9% would have an LCOH of $18.89, and a utilization rate of 99% would have an LCOH of $7.09 (see Figure 33 in Section 4.3 for details). Oversizing the electrolyzer allows for the generation of hydrogen while avoiding the peak demand period of 4 pm to 9 pm, which typically incurs higher demand charges. By operating at a 75 % utilization rate, the electrolyzer can produce hydrogen more efficiently and at a lower cost ($6.42 per kg of hydrogen), resulting in a lower LCOH overall.

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CHAPTER 1. INTRODUCTION

The California Air Resource Board (CARB) has adopted the "Innovative Clean Transit" (ICT) regulation to fund clean initiatives, which will lead to widespread adoption of zero emissions bus fleets in California, including hydrogen buses. It was enacted in December 2018 to replace various transit agencies' existing internal combustion engine (ICE) fleets. The rule mandates that all public transportation agencies progressively migrate to a zero-emission bus fleet, encouraging them to deliver innovative first- and last-mile connectivity and greater mobility for transit users (CARB, 2022). Under ICT regulation, public transit agencies must switch to 100% zero-emission buses by 2040 (CARB, 2019a). While technologies like CNG, LNG, hybrid, and biodiesel can reduce tailpipe emissions, only electric and hydrogen fuel cell buses are considered true zero-tailpipe emission options.

Humboldt County and the cities of Arcata, Eureka, Fortuna, Rio Dell, and Trinidad formed HTA in 1975 as a joint powers authority (JPA). HTA is largely supported by tolls and Transportation development Act (TDA) monies provided by JPA members. HTA is headquartered in Eureka, the county seat, and is managed by a seven-member Board of Directors, with one representative from each of the five incorporated communities and two from the County of Humboldt (HTA, 2022a). HTA operates and maintains five transit systems (refer to section 2.1 for more details). HTA has a history of innovation in clean transit and is working towards compliance with this new regulation.

HTA has opted for hydrogen fuel cell buses, and this study will determine the most economically viable method for procuring hydrogen.

HTA currently operates 21 ICE buses (Singh, 2021). Under the CARB mandate, HTA will replace its current ICE fleet with zero-tailpipe emission vehicles such as battery electric buses (BEB) or fuel cell buses (FCEB). As per previous studies, the HTA requires an average of 600 kgs of hydrogen per day to operate these 21 transit buses if all were using hydrogen (Singh, 2021). If the hydrogen generating infrastructure is larger than needed to produce 600 kgs of hydrogen per day, the transit agency can take advantage of this excess capacity by generating hydrogen during times when electricity prices on the grid are low. Specifically, producing hydrogen during off-peak and super-off-peak hours may be a cost-effective strategy for meeting the agency's hydrogen requirements, if the savings from reduced operating costs are higher than the increased upfront cost to construct a higher capacity production facility. Such a method may reduce the cost of generated hydrogen while also reducing the payback period for the capital investment. Exploring the range of options and identifying a least-cost option for sizing and operation of the hydrogen production system is the focus of this work.

It is vital to conduct such an analysis right now, as HTA has been awarded a $38.7 million grant by California State Transportation Agency (CalSTA) for HTA to expand its transit services and introduce zero-emission fleets on California's North Coast (CalSTA, 2022). To achieve this goal, HTA has proposed to procure 11 FCEBs, install supportive hydrogen fueling infrastructure, and construct an intermodal transit and housing center (CalSTA, 2022). This study will help to determine under what conditions and arrangements adding new infrastructure for on-site hydrogen production are economically viable for HTA, compared to alternative sources of hydrogen.

The primary alternative to on-site hydrogen production for HTA is to procure liquid hydrogen from Air Products (HTA, 2022b). This hydrogen is manufactured using natural gas and a production technique known as Steam Methane Reforming (SMR). This method of hydrogen production is independent of the grid's emission intensity and location, as it requires minimal electricity. Moreover, SMR plants emit 8 to 12 kg of CO_2 for each kg of hydrogen produced as natural gas as a feedstock for producing hydrogen (Blank & Molly, 2020). The hydrogen industry has a practice of assigning "colors" to various hydrogen production pathways, and SMR hydrogen is known as "Gray" hydrogen due to the relatively high GHG emissions associated with this process compared to other options. More details about this process are discussed in section 2.7.1.

Electrolytic hydrogen generated using renewable energy, also known as "green" hydrogen, can provide a cleaner pathway for generating hydrogen. In this process, water is split into hydrogen and oxygen using electricity. When the electricity used comes from clean -renewable resources, the emissions associated with the generation of one kilogram of hydrogen become negligible (TERI, 2022). Section 2.7.2 provides further explanation of the electrolytic hydrogen generation process.

The cost of on-site hydrogen production depends strongly on the electricity costs. In this research, three electricity rate structures were analyzed for their impact on the production of hydrogen, namely B-20 (T), BEV-2, in combination with E-GT (to procure 100% renewable electricity from the grid), and real-time pricing (RTP) from Pacific Gas

& Electric Company (PG&E). At present, of the utility rate schedules mentioned above, only the B-20 and BEV structures are accessible to retail consumers, with the BEV rate structure exclusively designated for charging battery electric vehicles. Nonetheless, this analysis employs both rate structures to evaluate the effects of high demand charges (in B-20) and high energy charges (in BEV) on the levelized cost of hydrogen (LCOH). It should be noted that RTP is currently unavailable to retail consumers. However, RTP is incorporated in this study (with a hypothetical demand charge) to assess the potential impact of exposing hydrogen generation to RTP in the future. Furthermore, the study also examines the levelized cost of hydrogen (LCOH) when a battery and solar photovoltaic (PV) system are used to support the electric load required for hydrogen production, in addition to the utility rate schedules.

Currently, only 11 FCEBs are being procured by HTA so the daily hydrogen demand is lower than the 600 kg as claimed in previous studies. HTA had provided an 8-year hydrogen demand estimates (as shown in Table 1), and these demand estimates are being used in this study to calculate the levelized cost of hydrogen (Qiriazi, 2022). This analysis was based on the projected demand for hydrogen, which is currently limited to the operation of 11 fuel cell electric buses (FCEBs) and is expected to increase as more internal combustion engine (ICE) buses are replaced.

Table 1. Hydrogen Consumption Targets. Source: (Qiriazi, 2022)

Year	1 to 3	4 to 5	6 to 7	8 to 10	10 yrs. average
Daily Hydrogen consumption targets (kg)	295	378	628	737	511

Various sectors are responsible for GHG emissions, such as energy, transportation, industrial, etc. The total global GHG emissions from the energy sector alone in the year 2019 were 0.037 gigaton of CO_2 eq ($3.7 * 10^4$ $MtCO_2eq$), and the transportation sector was responsible for 0.03 gigaton of CO_2 eq ($3.4*10^4$ $MtCO_2eq$) of GHG emissions in the same year (IEA, 2021). According to an ongoing temperature investigation undertaken by NASA's Goddard Institute of Space Studies (GISS), the average global temperature on earth has risen by at least 1.1 degrees Celsius (1.9° Fahrenheit) since 1880. Most warming happened after 1975 at a pace of 0.15 to 0.20 degrees Celsius each decade (Hansen et al., 2010).

Global transportation demand supports burning petroleum-based fuels, particularly gasoline and diesel, which contribute to GHG emissions. Countries and organizations across the world are collaborating to reduce these emissions by setting highly ambitious and aggressive GHG reduction objectives. The United States has set an ambitious but attainable goal of reducing net GHG emissions by 50-52% below 2005 levels by 2030 (Figure 1) (USDoS, 2021). This is the critical decade for implementing a set of new policies to accelerate existing emissions reduction trends by rapidly expanding the deployment of new technologies such as electric vehicles and heat pumps and by building the infrastructure for critical systems such as our national power grid (TRS, 2022).

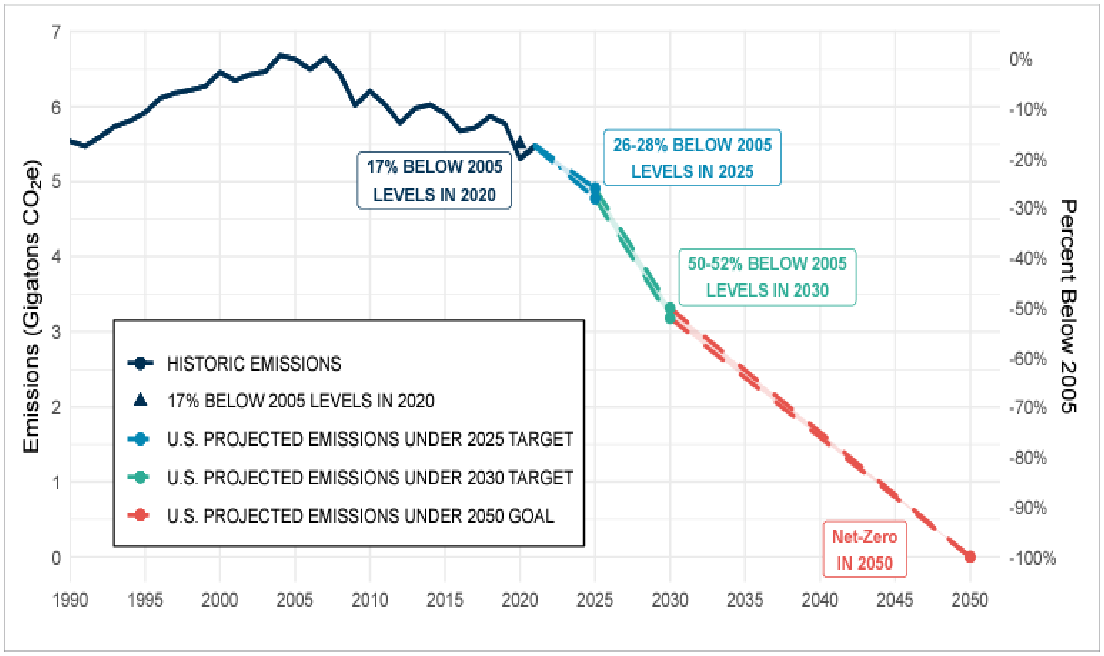

Figure 1. United States historic emissions and projected emissions under the 2050 goal for net-zero. Source: (USDoS, 2021)

The state of California, which alone accounted for about 14.8% of the USA's gross domestic production (GDP) in 2021 (Buchholz, 2022), is also implementing various policies to adhere to national and state goals. CARB has laid out ambitious plans to reduce the state's dependency on fossil fuels and achieve carbon neutrality by 2045 (CARB, 2022c). CARB envisions achieving this target through a historic shift away from fossil fuels in all sectors of the economy as well as a quick transition to renewable energy resources and zero-emission vehicles. According to this, by 2045 California will achieve the following targets (CARB, 2022c):

1. Cut GHG emissions by 85% (below 1990 levels).

2. Reduce smog forming air pollutants by 71%.
3. Reduce fossil fuel (liquid petroleum) demand by 94%.
4. Create 4 million new jobs.
5. Save California $200 billion in health-care expenses by 2045.

California’s transport sector is responsible for approximately 41% of its overall GHG in 2019 (Figure 2), nearly 80% of its nitrous oxide (N_2O) pollution, and 90% of its diesel particulate matter pollution (CARB, 2019) (CEC, 2022). To meet clean air requirements and combat climate change, the current fossil fuel dependent transportation sector must switch to low-carbon fuels and zero- or nearly-zero emission technologies. The California Energy Commission (CEC) invests about $100 million annually into California’s transportation sector towards ‘cleaning’ it and carrying out research related to the transportation trends (CEC, 2022).

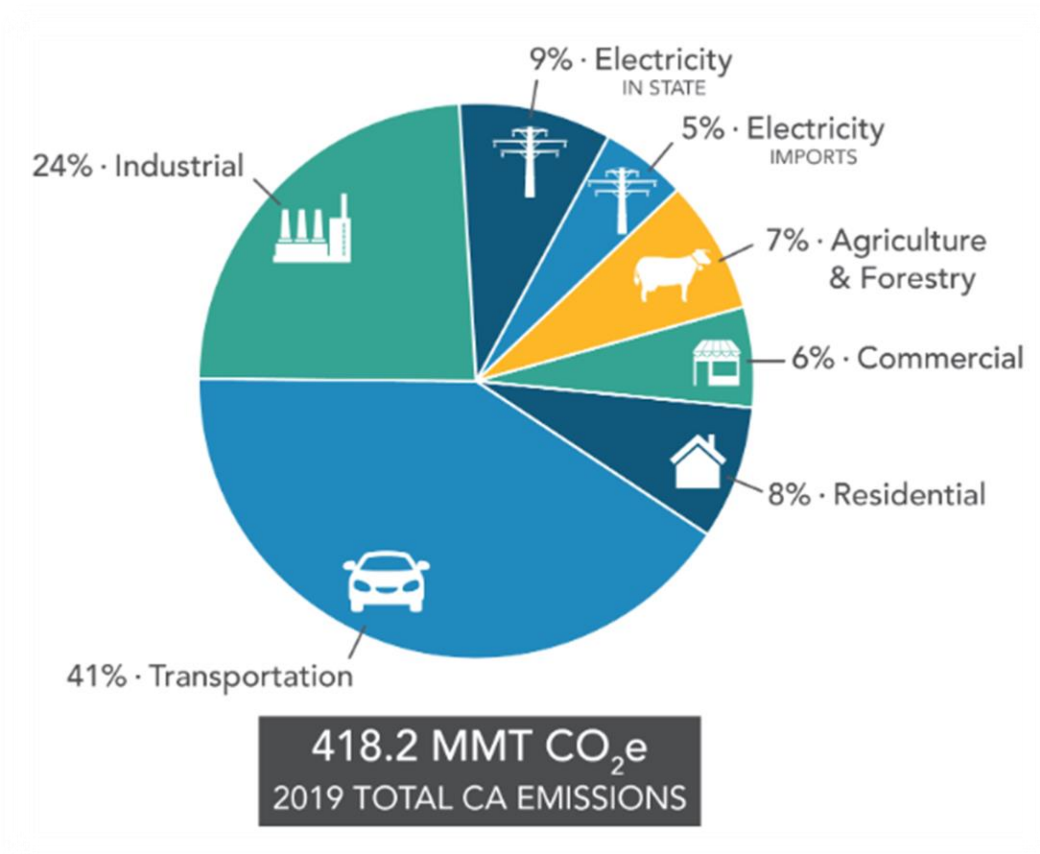

Figure 2. California's GHG emissions in 2019 broken up by economic sectors. Source: (CARB, 2019)

California has established several state and sector-wide regulations to contain emissions by adopting renewable and sustainable alternatives to all sectors, including the transportation sector. In attempts to reduce the GHG emissions from California's transport sector, CARB has initiated a one-of-a-kind regulation in the United States that sets the statewide goal for public transit agencies to gradually transition to 100% zero emission bus fleets by 2040 (CARB, 2018b). This initiative is called the Innovative Clean Transit (ICT) regulation.

The ICT was adopted in early December 2018 and requires all public transit agencies to transition to a 100% zero emission bus (ZEB) fleet. By the beginning of 2029, 100% of the new purchases by transit agencies must be ZEBs, with the goal of a complete transition by 2040 (CARB, 2019a). Adoption of this new regulation raises a lot of questions for the transit agencies, such as what kind of ZEBs would be more techno-economically feasible for them.

Various technologies, such as battery electric vehicles (BEV), mild-hybrid electric vehicles (MHEV), plug-in hybrid electric vehicles (PHEV), and fuel cell electric vehicles (FCEV), have been proposed as alternatives to the conventional internal combustion engine vehicle. However, due to the transportation sector's reliance on conventional fossil fuels, emissions from that sector have essentially remained unchanged. This suggests that if the energy needs of the transportation sector are satisfied by using electricity, the carbon emissions from the sector would likewise decrease over time as we observe a rise in the generation of more renewable electricity. Figure 3 illustrates how carbon emissions from the electricity generation sector have decreased over time as a result of technological advancements related to the production of electricity from conventional fossil fuels, such as natural gas and coal, and a greater uptake of renewable electricity generation sources, like solar photovoltaic (PV), and wind.

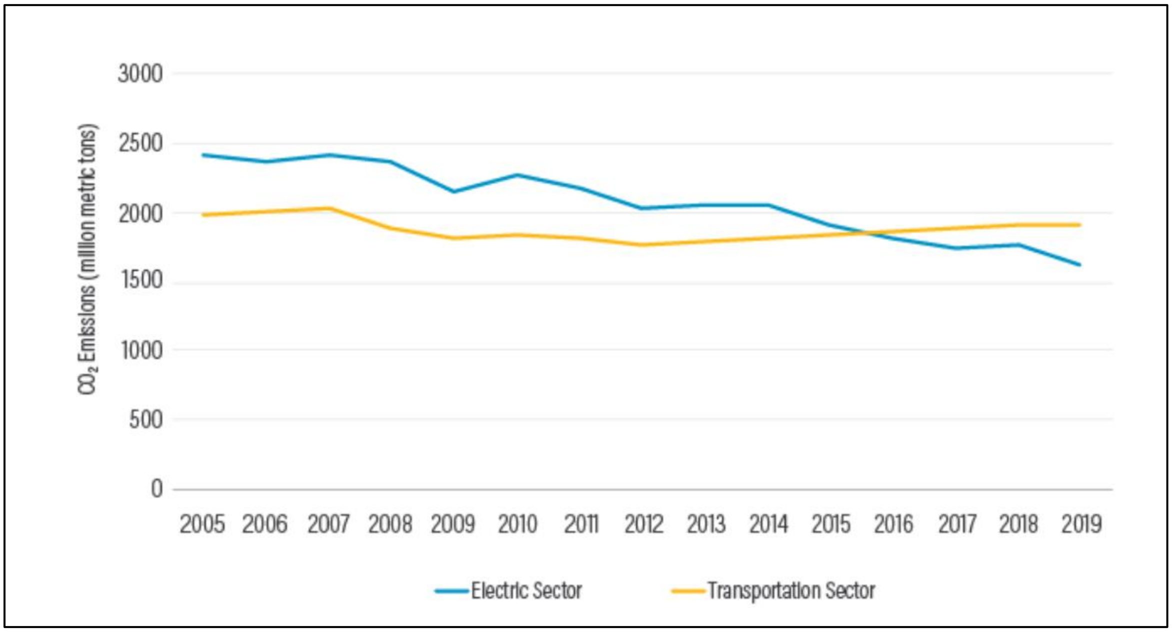

Figure 3. Transportation CO_2 emissions surpass electric CO_2 emissions in 2022. Source: (S., 2020)

As mentioned above, HTA has chosen to move ahead with FCEBs in order to comply with the ICT targets, as the HTA has been awarded a $38.75 million grant by the California State transportation agency under the Transit and Intercity Rail Capital Program (TIRCP) (HTA, 2022b). Under this grant, the HTA has proposed to procure 11 New Flyer fuel cell electric buses (as shown in Figure 4 below) and a hydrogen fueling station at HTA's Eureka, CA facility.

Figure 4: Testing of New Flyer bus in Humboldt County. Source: (HTA, 2022b)

HTA also has plans to include public dispensers for light duty and medium duty vehicles to help develop a hydrogen fueling network and supply chain on California's North Coast (HTA, 2022b). Currently, HTA has partnered with Air Products Inc., who will be responsible for the design and construction of the hydrogen fueling station, which will provide hydrogen for the operation of FCEBs (HTA, 2022b).

The objective of this study is to determine the technical and economic feasibility of on-site electrolytic hydrogen production. The study will also look for energy and policy pathways to reduce the levelized cost of electrolytic hydrogen, and the LCOH generated by three distinct energy pathways will be evaluated i.e.:

1. Electrolysis utilizing grid electricity supplied by PG&E at B-20 and BEV rate structure.
2. Electrolysis utilizing electricity from a mix of on-site solar PV, battery, and PG&E grid.

3. Electrolysis utilizing grid electricity supplied at RTP and supportive sensitivity analysis of LCOH for various demand charges.

This research will assist in determining the optimal method for procuring or generating hydrogen to fuel the planned fleet of FCEBs given both currently available and possible future electricity tariff structures. The study's model incorporates various parameters such as the optimal hourly hydrogen generation profile, the energy consumed for generating and storing hydrogen, the optimal solar PV and battery sizing to support hydrogen production, and other factors to compute and compare various cost parameters associated with hydrogen generation. Government credits, capital expenditures, infrastructure costs, and operation and maintenance (O&M) costs are all included.

For the economic and environmental impact of the public transit network, the model compares the cost and GHG emissions of hydrogen obtained via Air Products with on-site hydrogen generation via electrolysis. In this study, existing models and tools such as the National Renewable Energy Laboratory’s (NREL) REopt tool, and CARB's Low Carbon Fuel Standard (LCFS) credit calculator were used to determine some of the technical and economic factors.

This thesis computes the levelized cost of on-site electrolytic hydrogen from 2023 to 2038 and compares procured hydrogen versus on-site hydrogen. Furthermore, this thesis discusses how various hydrogen pathways might assist in cutting GHG emissions from public transportation while meeting state and federal laws by 2040. The thesis is structured as follows.

The findings of the literature review are presented in Chapter 2, together with the background studies on GHG emissions from California's transportation sector, as well as the federal and state government plans and strategies to reduce these emissions. Chapter 2 also discusses the zero-emission technologies under consideration for this project, their implications, and the infrastructure required, such as hydrogen fueling stations.

Following the literature review, Chapter 3 explains the methods used to calculate the LCOH generation, including assumptions, data collection, and calculations. It also explains how the model determines the cost of technologies and infrastructure implementation.

Chapter 4 highlights the study's findings, which include a full analysis and model results. This chapter also goes over the specifics of the most cost-effective solution for HTA.

The results section is followed by Chapter 5, Discussion and Recommendations. This section describes the study's findings and how to interpret them. It also includes proposals for the HTA to reduce GHG emissions and become a net zero carbon transit agency.

CHAPTER 2. BACKGROUND AND LITERATURE REVIEW

Studies from the early 1860s have shown that some researchers and scientists had found evidence that change in atmospheric carbon dioxide levels could substantially impact global temperatures through the greenhouse gas effect (Shaftel, et al., 2022). The rising level of CO_2 emissions is shown in Figure 5. John Tyndall, a physicist, observed the Earth's inherent greenhouse effect and proposed that little changes in air composition may cause climatic variations (Holly Shaftel et al., 2022). In 1896, Swedish scientist Svante Arrhenius predicted in a seminar article that variations in atmospheric carbon dioxide levels might significantly influence surface temperature via the greenhouse effect(Arrhenius, 1896) (Shaftel, et al., 2022).

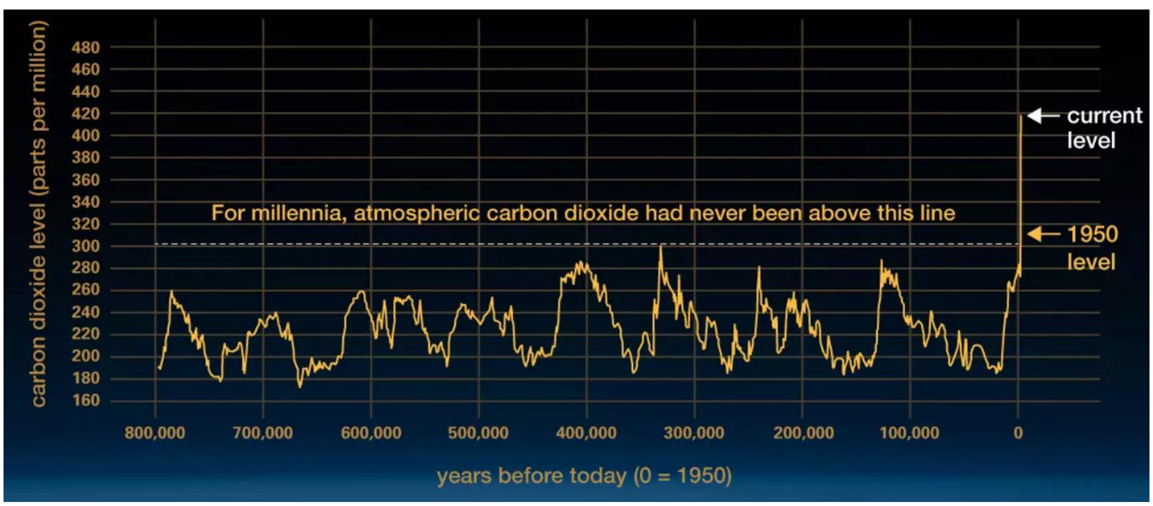

Figure 5. Atmospheric samples contained in ice cores and more recent direct measurements, provides evidence that atmospheric CO_2 has increased since the Industrial Revolution. Source: (Shaftel, et al., 2022)

The rise in greenhouse gases in the atmosphere is due to human activities over the last 150 years. In the United States, the burning of fossil fuels for electricity, heat, and transportation is the largest source for greenhouse gas emissions (EPA, 2022c). The global average temperature has risen by 0.14° Fahrenheit (0.08° Celsius) per decade. Furthermore, the rate of warming since the early 1980s is more than twice that: 0.32° F (0.18° C) per decade. As per National Oceanic and Atmospheric Administration's (NOAA) data, 2021 was the sixth warmest year yet recorded, as shown in Figure 6 (Lindsey & Dahlman, 2022) .

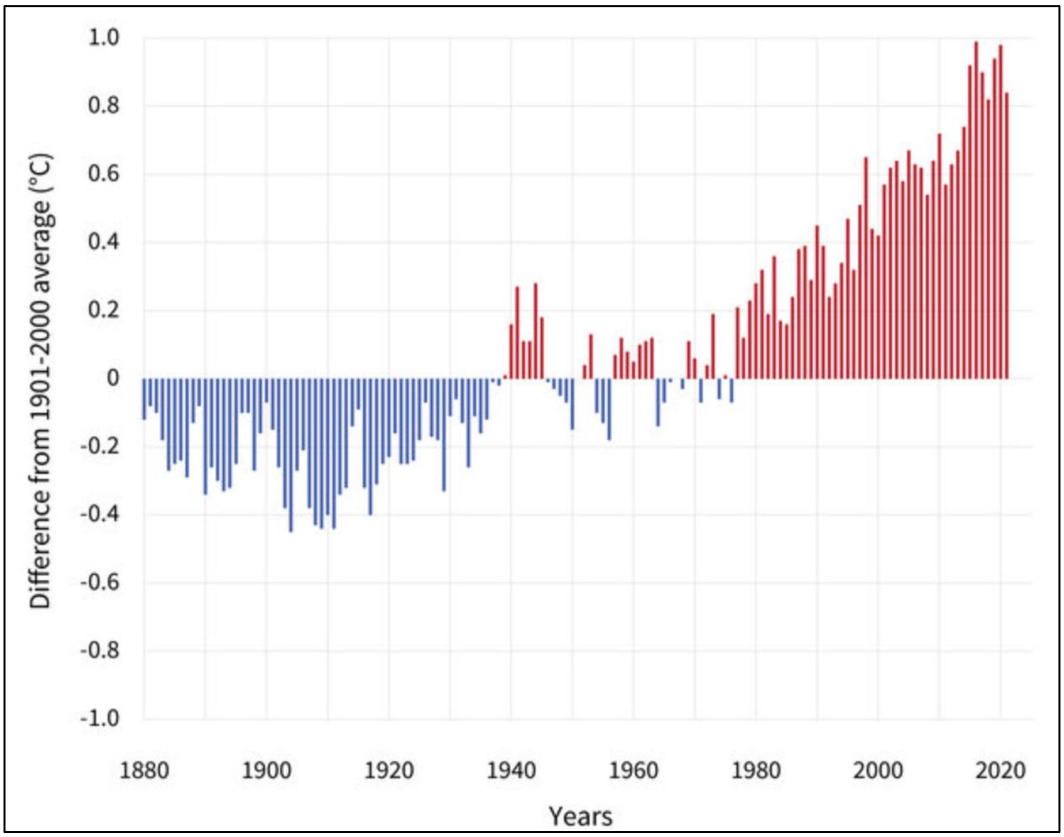

Figure 6. Deviation of global average surface temperature. Source: (Lindsey & Dahlman, 2022)

Greenhouse gases (GHG) primarily consist of carbon dioxide (CO_2), methane (CH_4), nitrous oxides (N_2O) and Fluorinated gases such as hydrofluorocarbons, perfluorocarbons, sulfur hexafluoride, and nitrogen trifluoride (EPA, 2022b). GHGs act like a blanket around the Earth, absorbing and slowing the rate of energy/heat escaping to space. This slow heating up of our planet due to the GHG gasses produced as a result of human activities cause anthropogenic climate change. The distinguishing factors between these gases are their "radiative efficiency" or ability to absorb energy and their "lifetime" or duration in the atmosphere (EPA, 2022a). To compare the global warming impact of different gases, the Global Warming Potential (GWP) was created. The GWP measures the amount of energy one ton of a gas can absorb over a specific time period in comparison to one ton of CO_2 emissions (EPA, 2022a). The GWP of GHG emissions is evaluated by the Intergovernmental Panel on Climate Change (IPCC) to reflect their climate impact compared to CO_2 emissions. This calculation is based on the infrared absorption intensity and atmospheric lifetime of each GHG. The GWPs are determined over a specific time duration and all the GWPs utilized for GHG inventory purposes are evaluated over a 100-year period (CARB, 2022a).Table 2 shows the GWP values of the major greenhouse gases.

Table 2. 100-yr GWPs from the IPCC second assessment report (SAR) and fourth assessment report (AR4). Source: (CARB, 2022a)

Gas Name	**Formula**	**Lifetime (years)**	**SAR GWP**	**AR4 GWP**	**Percent Change**
Carbon Dioxide	CO_2		1	1	
Methane	CH_4	12	21	25	19%
Nitrous Oxide	N_2O	114	310	298	-3.90%

As mentioned above these GHGs stay in the atmosphere for an extended period and mix globally in the atmosphere, making reduction of emissions a matter of global concern that must be tackled on a global front not just by specific countries. As previously mentioned, the rising levels of GHGs are fueled primarily by increasing human activities and economic growth. The per capital GHG emissions for 2018 are shown in Figure 7.

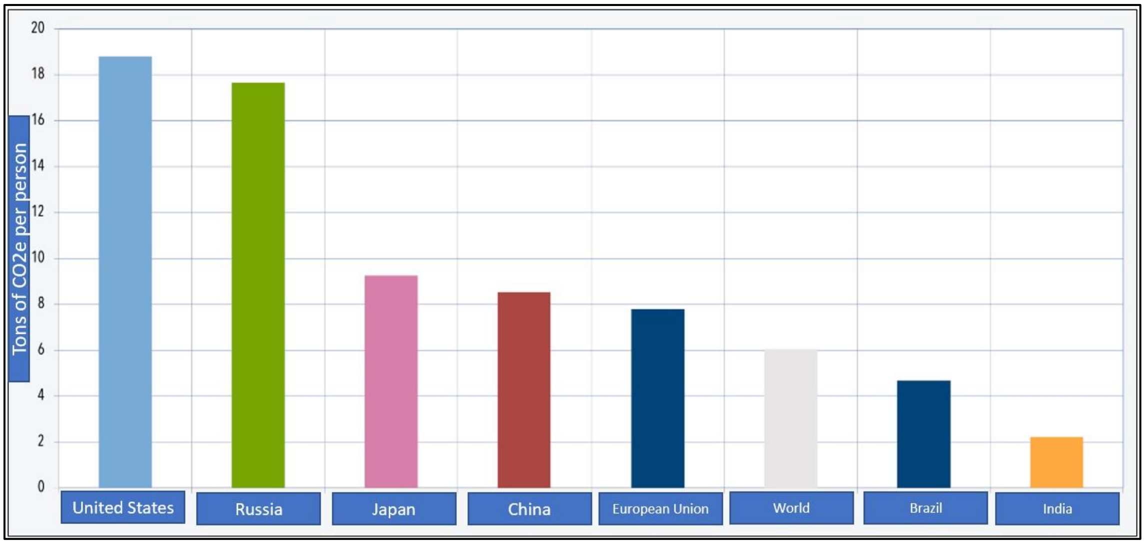

Figure 7. Per Capita Greenhouse Gas Emissions, 2018. Source: (C2ES, 2018)

According to the United States Environmental Protection Agency (EPA), the transportation sector is the largest sectoral source of anthropogenic greenhouse gas (GHG) emissions in the United States, overtaking the electricity generating sector in 2016 (Yale, 2017). In the year 2020, the transportation sector accounted for 27% (as shown in Figure 8 below) of total U.S. GHG emissions, according to the Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2020 (US EPA, 2022). Greenhouse gas (GHG) emissions from the transport sector have surpassed emissions from the electricity generation sector, as power plants have become more efficient and shifted towards natural gas and renewables sources. Decarbonizing the transport sector remains a challenge as it relies heavily on fossil fuels and continues to grow as a larger GHG contributor. Addressing this sector is crucial to mitigating GHG emissions as it continues to be a significant contributor to climate change.

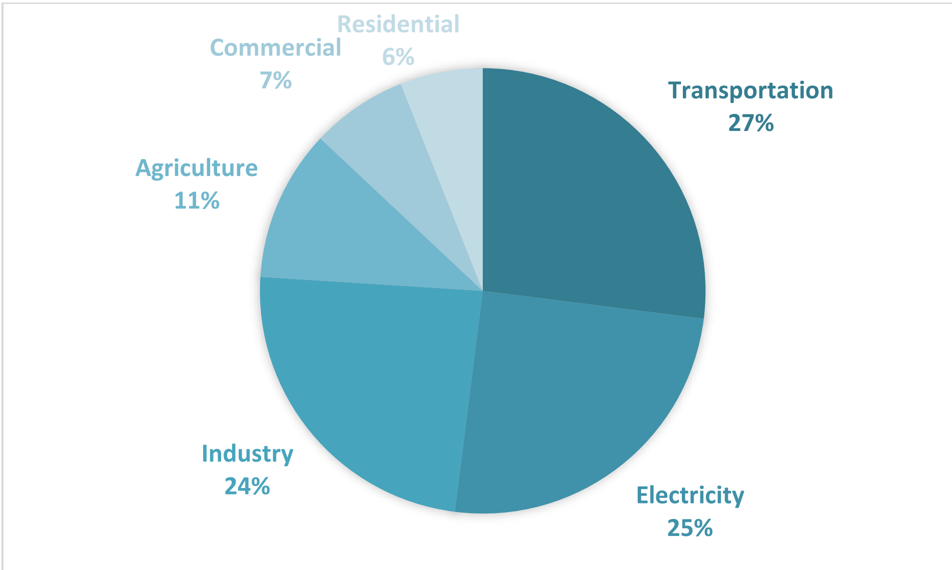

Figure 8. 2020 U.S. GHG Emissions by Sector. Source: (US EPA, 2022)

Despite being heavily impacted by the COVID-19 pandemic, the global transport sector accounted for 23% of GHG emissions in 2022 (IEA, 2022b). Global CO_2 emissions from the transportation industry increased by 8% to roughly 7.7 Gt CO_2 in 2021, as pandemic restrictions were relaxed and passenger and freight movements began to recover after a historic decrease in 2020 (IEA, 2022a).

The transportation sector has been heavily dependent on fossil fuel based energy sources: namely diesel, gasoline, and other petroleum products of its energy requirement. Rapidly increasing emissions from the transport sector and increasing demands of conventional fuel have motivated efforts to transition from conventional fossil fuel-dependent ICE vehicles to zero or near zero tail pipe emissions vehicles such as electric vehicles, fuel cell vehicles and hybrid vehicles. In the United States, federal and state government are leading aggressive efforts to reduce the country's GHG emissions. These state or federal emission reduction targets would be very difficult to achieve without reducing the emissions from the transport sector. To achieve climate goals, various policies and initiatives such as regulation on the sale of ZEV, subsidies on ZEV, Low Carbon Fuel Standards (LCFS) and other ZEVs infrastructure incentives are being implemented by federal and state government. In line with its climate change targets, on January 20, 2021 the US rejoined the Paris climate change agreement under the Biden Administration (Blinken, 2021). In addition to this, the Biden Administration has set a target of 50-52% reduction in GHG emissions from 2005 levels by 2030 (House, 2021).

As stated earlier, one of the policy tool available with federal and state government to reduce GHG emissions from the transportation sector is to mandate the sale of new ZEVs. As per data submitted to the Bureau of Transportation Statistics, the United States has more than 270 transit agencies operating on almost 10,000 routes providing public transportation services (BTS, 2022). As per the Center of Transportation and the Environment, the entire US transit fleet can transition to ZEVs by 2035 with an investment between $56 billion to $88 billion (CTE, 2021). According to recent Federal Transit Administration data, agencies operated 1,548 electric buses in 2021. This represents around 2.5 percent of the 61,893 buses on the road, which include commuter buses, bus rapid transit, and trolley buses (Ben Miller, 2022). Replacing conventional

ICE public transit buses with ZEV alternatives results in significant GHG savings. A conventional ICE bus produces approximately 0.39 pounds of CO_2 eq GHG emissions per passenger mile traveled, which can be reduced to zero by using ZEV alternatives (Congressional Budget Office, 2022).

2.1 Humboldt Transit Authority (HTA)

Humboldt County and the cities of Arcata, Eureka, Fortuna, Rio Dell, and Trinidad formed HTA in 1975 as a joint powers authority (JPA). HTA is largely supported by tolls and Transportation development Act (TDA) monies provided by JPA members. HTA is headquartered in Eureka, the county seat, and is managed by a seven-member Board of Directors, with one representative from each of the five incorporated communities and two from the County of Humboldt (HTA, 2022a). HTA operates and maintains five transit systems (as shown in Figure 9 below). In addition to that, HTA offers services in partnership with the Blue Lake Rancheria.

1. Redwood Transit System (RTS)
2. Willow Creek Transit Service
3. South Humboldt Transit Systems
4. Eureka Transit Service
5. Arcata & Mad River Transit System (AMRTS)

Figure 9. HTA routes map. Source: (HTA, 2022a)

As stated earlier, HTA has been awarded a $38.7 million grant by CARB under the TIRCP for purchasing 11 New Flyer FCEBs and setting up a light- and heavy-duty vehicle hydrogen fueling station. In addition to the existing six transit routes, HTA also plans on utilizing the TIRCP grant to start a new intercity transit service, the Redwood Coast Express (RCX) (as shown in Figure 10 below), that will be served by the New Flyer buses (HTA, 2022b). This service will connect local riders to Ukiah and points south, including the San Francisco Bay Area (HTA, 2022b).

Figure 10. Proposed route for the new Redwood Coast Express. Source: (HTA, 2022b)

As per an analysis conducted by Aditya S. Kushwah in 2021, HTA would require 600 kgs of daily H_2 along with other supporting infrastructure to replace its 21 existing ICE buses with FCEBs (Kushwah, 2021). However, since the study was conducted, HTA's hydrogen requirements have changed. Currently, HTA is procuring only 11 FCEBs, resulting in a daily hydrogen demand of approximately 295 kgs. This demand is expected to increase to 737 kgs daily over the next eight years as HTA transitions from ICE buses to FCEBs (Qiriazi, 2022). Hence for this thesis the levelized cost of hydrogen is calculated assuming daily hydrogen production of about 300 kg in the first year that expands to about to 750 kg over time, as shown in Table 3 below.

Table 3: Daily hydrogen consumption targets. Source: (Qiriazi, 2022)

Year	1 to 3	4 to 5	6 to 7	8 to 10
Daily Hydrogen consumption targets (kg)	295	378	628	737

2.2 US Policies and incentives to reduce GHG emissions from the public transit system

Decoupling the transport sector from fossil fuel based energy source could have an adverse impact on the economic growth of the country. However, if this transition is made in a well-executed and well-planned manner it could lead to environmentally sustainable economic growth and creation of new green jobs in the transportation sector. The execution of policies in the transportation sector is very important as the emissions from this sector have relatively remained consistent (except in 2020 due to COVID-19 pandemic) despite reduction in the electricity power generation sectors, as shown in Figure 11.

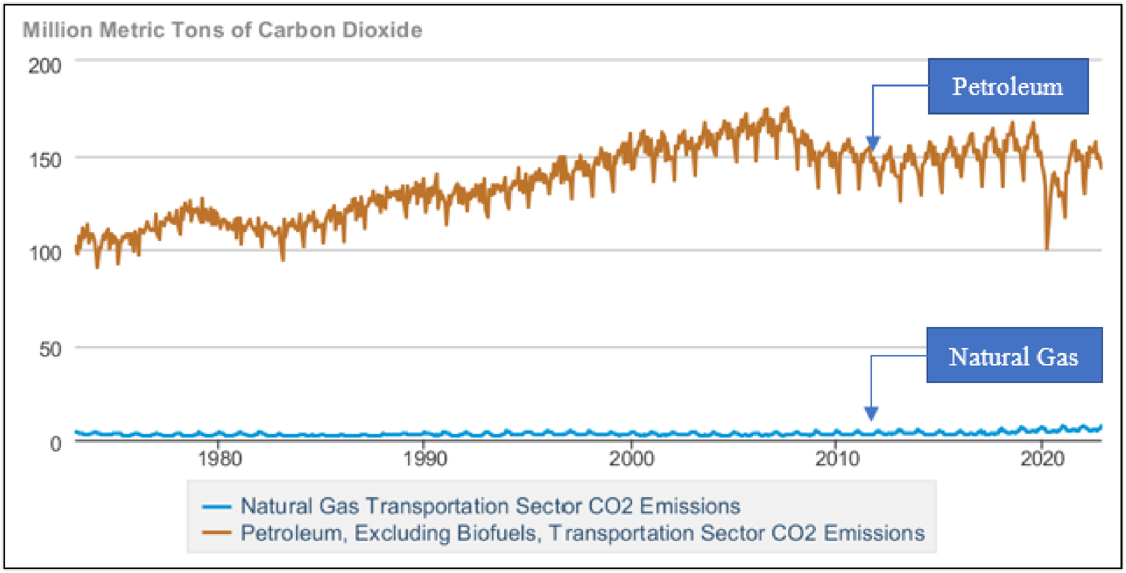

Figure 11. CO_2 emissions by the transportation sector, 1973–2021. Source: (EIA, 2022)

In 2020, 83% of the total emissions from the transport sector were due to road transport vehicles (as shown in Figure 12 below).

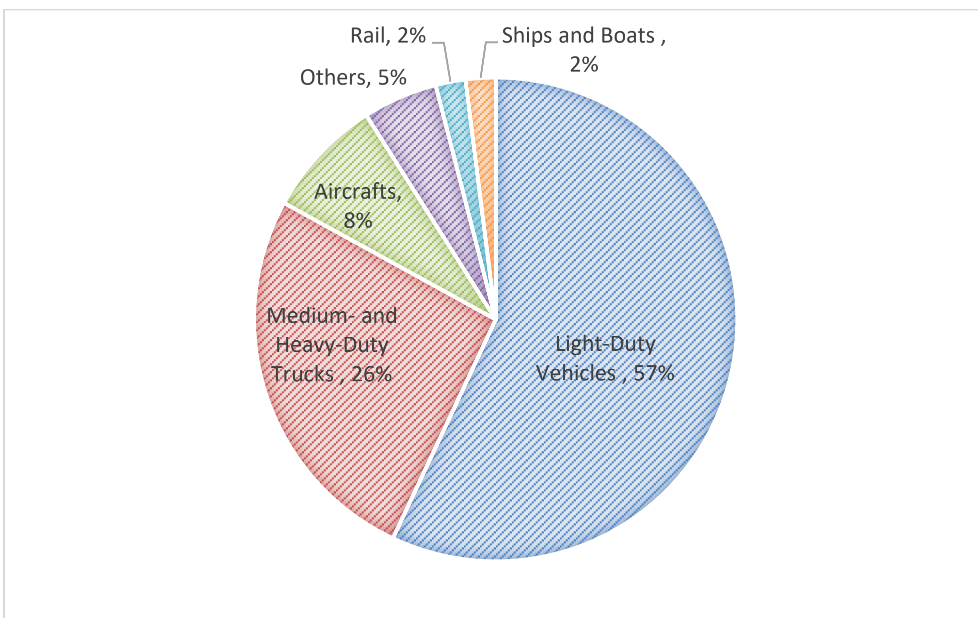

Figure 12. 2020 U.S. Transportation Sector GHG Emissions by Source. Source: (US EPA, 2022)

By 2035, all new automobiles and passenger trucks sold in California must be ZEVs, according to California Governor's Executive Order N-79-20. CARB is required in the order to develop and recommend ways to achieve 100% zero-emissions from medium and heavy-duty on-road vehicles in the state by 2045, where possible, and by 2035 for drayage trucks(CARB, 2022b). The roadmap developed by CARB can be divided into two sections incentives and regulations (CARB, 2022b).

1. Incentives: Incentives are crucial for advancing and widely deploying zero-emission technology while also offering immediate emission reductions to help us fulfill our air quality and climate goals. Some of the major incentives offered by CARB are stated below.
    a. Carl Moyer Program: The Carl Moyer Program promotes the use of clean technology in early fleet and equipment turnover by offering incentives to replace old cars and equipment with the cleanest possible.
    b. Community Air Protection Incentives for On-Road Heavy-Duty Vehicles: Local air districts direct funds through this incentive, focusing on modern technology where practicable, to enhance air quality in communities of concern.
    c. Low Carbon Transportation Program: This initiative focuses on promoting technologies through zero-emission demonstration projects and on-road zero-emission technology deployment.

d. Truck Loan Assistance Program: The program assists small-business fleet owners affected by CARB's In-Use Truck and Bus rule in obtaining finance to upgrade their fleets with newer, cleaner trucks.

2. Regulations: CARB works closely with stakeholders to ensure that regulations are both technically viable and cost-effective. These regulations may compel manufacturers to develop and market zero-emission technologies, as well as boost or hasten user acceptance of those technologies.

    a. Innovative Clean Transit: By 2040, all public transportation agencies must progressively transition to a 100% zero-emission bus fleet. By 2026, 50% of large transit agencies' new bus purchases and 25% of minor transit agencies' new bus purchases must be zero-emission buses. By 2029, all new buses purchased by big and small transit agencies must be zero-emission buses.

    b. Zero Emission Airport Shuttle: By the end of 2027, an airport shuttle fleet must contain 33% zero-emission shuttles. By the end of 2035, all of the company's shuttles must be zero-emission.

    c. Zero Emission Powertrain Certification: This regulation established a heavy-duty zero-emission powertrain standard and certification process, which will aid in reducing variability in the quality and reliability of heavy-duty electric and fuel cell vehicles, ensuring information about these vehicles and their powertrains is effectively and consistently communicated to purchasers, and accelerating progress toward greater vehicle reparability.

d. Advanced Clean Trucks: This regulation will hasten the transfer of zero-emission medium and heavy-duty vehicles from Class 2b to Class 8. From 2024 through 2035, manufacturers who certify Class 2b-8 chassis or entire vehicles with combustion engines would be compelled to offer zero-emission trucks as a growing percentage of their annual California sales. Zero-emission truck/chassis sales would need to account for 55% of Class 2b – 3 truck sales, 75% of Class 4 – 8 straight truck sales, and 40% of truck tractor sales by 2035.

In the following section this thesis discusses the various policies and initiatives adopted by CARB to reduce GHG emissions from heavy-duty public transit fleets in California. The upcoming sections discuss in detail about the ICT program, Low Carbon Fuel Standards (LCFS) and one of the more recent of policy initiatives the Inflation Reduction Act (IRA). All of these policies are aimed at promoting faster adoption of zero emission buses and incentives transportation technologies with zero tailpipe emissions or near zero emissions.

2.3 Innovative Clean Transit Program

The ICT regulation, which went into effect in December 2018, compels all public transportation providers to progressively shift to a ZEB fleet. Beginning in 2029, all new transportation agency acquisitions must be ZEBs, with an aim of complete transformation by 2040. It is applicable to all transit agencies that own, operate, or lease buses with GVWRs more than 14,000 lbs. including standard, articulated, over the road, double decker, and cutaway buses (CARB, 2019b). The purchase schedule for new ZEB is shown in Table 4 below. Transit agencies have different targets depending upon the size of the fleet they operate. Large transit agencies operate at least 100 buses in an urbanized area with a population of 200,000 or more, or more than 65 buses in annual maximum service in the South Coast or San Joaquin Valley Air Basins. Small transit agencies are those that do not meet these criteria. Note that the number of demand response buses is not included in the count of annual maximum service buses (CARB, 2019b). As per this classification, HTA is classified as a small transit agency.

Table 4. ZEB Purchase Schedule (ZEB Percentage of Total New Bus Purchases). Source: (CARB, 2019b)

Year	Large Transit	Small Transit
2023	25%	-
2024	25%	-
2025	25%	-
2026	50%	25%
2027	50%	25%
2028	50%	25%
2029	100%	100%

The ICT regulation has the following components:

1. Each transportation agency must submit a ZEB Rollout Plan, which must be authorized by its Board, outlining how it intends to achieve a full transition to zero-emission technology by 2040. Large transit

agencies must submit their Rollout Plans by July 1, 2020, and minor transit agencies must submit their plans by July 1, 2023.

2. ZEB purchases with numerous exclusions and compliance options to give transportation agencies with protection and flexibility.
3. Purchase of low-Nox engines unless transit vehicles are deployed from Nox-free zones.
4. Large transit agencies can use renewable diesel or renewable natural gas.
5. Reporting and record keeping requirements.

The full implementation of the ICT regulation today is estimated to cut GHG emissions by 19 million metric tons between 2020 and 2050, which is the equivalent of removing 4 million automobiles off the road. It would also cut hazardous tailpipe emissions (nitrogen oxides and particulate matter) by about 7,000 tons and 40 tons, respectively, over the same 30-year period (CARB, 2018b). The ICT regulation is also supported by the other policies such as LCFS credits which help support this transition by generation revenue to offset the high upfront cost for ZEB and their supporting infrastructure.

2.4 Low Carbon Fuel Standards (LCFS)

California enacted the LCFS regulation in 2009, with the goal of reducing the carbon intensity (CI) of transportation fuel consumed in California by at least 10% by 2020 compared to a 2010 baseline (CARB, n.d.). The Board authorized revisions in 2011 to clarify, simplify, and improve key elements of the regulation. The Board also adopted the clean fuel standard (CFS) in 2015 to remedy procedural concerns, and it went into effect on January 1, 2016. The Board authorized regulatory adjustments in 2018, including tightening and smoothing the CI standards through 2030 to align with California's 2030 GHG goal set through SB32 (CARB, n.d.).

The LCFS is intended to lower the carbon intensity of California's transportation fuel pool while boosting the availability of low-carbon and renewable alternatives, thereby reducing petroleum reliance and improving air quality. The CI of gasoline, diesel fuel, and their respective alternatives is stated in the LCFS standards. The concept is founded on the idea that each fuel emits "life cycle" GHG emissions such as CO_2, CH_4, N_2O, and other GHG contributors. The GHG emissions related to the manufacture, transportation, and consumption of a certain fuel are examined in this life cycle evaluation. The life cycle evaluation covers direct emissions from fuel production, transportation, and consumption, as well as major indirect effects on GHG emissions, such as changes in land usage for certain biofuels (CARB, n.d.). There are three basic requirements of LCFS:

1. Setting annual CI standards for each fuel. Benchmarking for gasoline, diesel, and the fuels that replace them.
2. CI is the measure of GHG emissions associated with fuel i.e., measured in grams of carbon dioxide equivalent per megajoule (gCO_2e/MJ) in association with the production, distribution, and consumption of the fuel.
3. CI is based on the complete life cycle analysis.

Public transit agencies such as the HTA can greatly benefit from the LCFS policy as they generate revenue for each mile travelled by ZEVs. HTA has shown interest in replacing its current fleet of ICE buses with FCEBs. Hence this thesis also looks at maximizing the LCFS credit generation pathways for HTA in addition to the fuel independence through electrolytic hydrogen generation.

2.5 Inflation Reduction Act (IRA)

In mid-2022, the US house of representatives approved a ten-year tax credit worth up to $3 per kilogram of "clean hydrogen" under the Biden administration's Inflation Reduction Act (IRA) (Mills, 2022) (Collins, 2021). Electrolytic hydrogen generated using renewable electricity, also known as green hydrogen, is claimed to cost $2.50-6/kg, whereas hydrogen generated using natural gas, also known as grey hydrogen, costs $1-2/kg, depending on natural gas prices (Peterson et al., 2020) (IEA, 2019). As a result, a $3/kg subsidy on green H_2 may significantly disrupt the US hydrogen market, by reducing the cost of green hydrogen and make it a more cost effective alternative to grey hydrogen. According to the House version of the bill, only hydrogen with lifetime GHG emissions of less than 0.45kg CO_2e per kg of H_2 will be eligible for the full $3 credit, which is expected to begin next year.

Hydrogen generated with higher emissions would only be eligible for smaller percentage of the clean hydrogen production tax credit rates, as follows (Collins, 2021):

1. 0.45 – 1.5 kg of CO_2e per kg of H_2 = 33.4% of the full tax credit ($1/kg of hydrogen)

2. 1.5 – 2.5 kg of CO_2 = 25% ($0.75/kg)
3. 2.5-4 kg of CO_2 = 20% ($0.60/kg)
4. 4-6 kg of CO_2 = 15% ($0.45/Kg)

It is important to note that hydrogen produced using the natural gas and conventional SMR generates about 8 to 12 kg of CO_2 emissions for every kilogram of hydrogen generated and hence will not qualify under IRA for credits (Blank & Molly, 2020).

2.6 Zero Emission Technologies for Public Transit Agencies

As mentioned above, under the ICT regulation, all public transit agencies must transition to 100% zero-emission bus fleets by the year 2040. Various technologies are available in the market which can be used to reduce tailpipe emissions compared to conventional fossil fuel dependent ICE buses, such as buses operated using compressed natural gas (CNG), liquid natural gas (LNG), hybrid, biodiesel, etc. However, these technologies can only reduce tailpipe emissions but cannot be classified as Zero Emission Vehicles. Two technologies, BEBs and FCEBs do not directly consume fossil fuel and are considered as zero- or near zero tailpipe emissions buses by the federal and state regulatory agencies. This makes these two technologies most favorable for transit agencies as they transition from ICE buses to ZEVs. The HTA has chosen FCEBs for transitioning to ZEV buses. This study will help HTA to determine which pathway of procuring hydrogen is more economically viable, i.e., procuring hydrogen from Air Products or on-site electrolytic hydrogen generation.

Even though, FCEBs have zero tailpipe emissions there are some indirect emissions associated with the generation of hydrogen depending upon the generation methodology and fuel source used to generated hydrogen, such as SMR or electrolysis with grid electricity and emissions associated with bus manufacturing. The emissions associated with hydrogen production can be reduced by generating hydrogen through electrolysis using renewable energy. Although HTA is currently a customer of Redwood Coast Energy Authority (RCEA), this study assumes that HTA will chooses to procure 100% renewable electricity from PG&E, the regional utility, as the PG&E rates are lower than RCEA equivalent rates (B-20-T) (RCEA, 2022). The following sections describe the technologies and require infrastructure for generation on-site hydrogen and operating FCEBs.

2.6.1 Fuel Cell Electric Buses

FCEBs are recognized as zero emission vehicles by both federal and state governments. These buses do not emit any GHG tailpipe emissions like conventional ICE buses. On-board stored hydrogen is fed into an onboard fuel cell “stack” that converts the chemical energy of the fuel into electrical energy rather than burning it. The electric motors of the vehicle (illustrated in Figure 13 below) are powered by this electricity. The automobile produces no tailpipe emissions, with only clean water vapor being emitted.

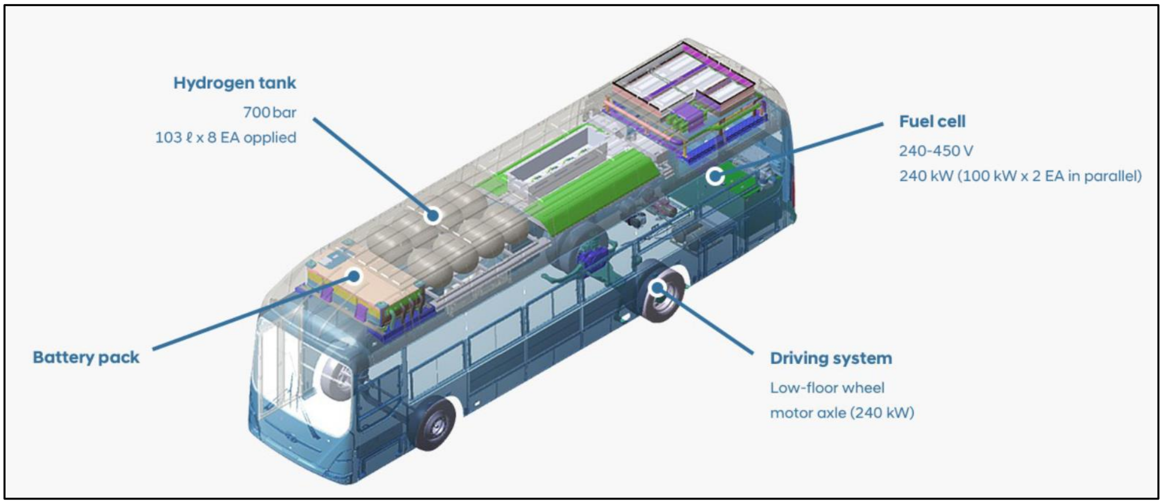

Figure 13. FCEB component layout. Source: (Hyundai, n.d.)

FCEBs have two major advantages over battery electric buses (BEBs). Firstly FCEBs have range equivalent to conventional ICE buses and secondly, offer faster refueling times (around 10 to 15 mins) (NanoSUN, 2023) compared to BEBs (2 to 3 hours with fast chargers) (Proterra, 2020).

Fuel cells generate electricity by an electrochemical process and generate water vapors as a by-product, as shown in Figure 14 below. An anode, a cathode, and an electrolyte membrane make up a fuel cell. A typical fuel cell functions by transferring hydrogen through the anode and oxygen via the cathode. A catalyst at the anode site separates hydrogen molecules into electrons and protons (H^+). The protons are driven through the porous electrolyte membrane, while the electrons are propelled through a circuit, resulting in an electric current and surplus heat. Protons, electrons, and oxygen mix at the cathode to form water molecules (H_2O). Fuel cells work silently and with excellent dependability because there are no moving components (FCHEA, n.d.).

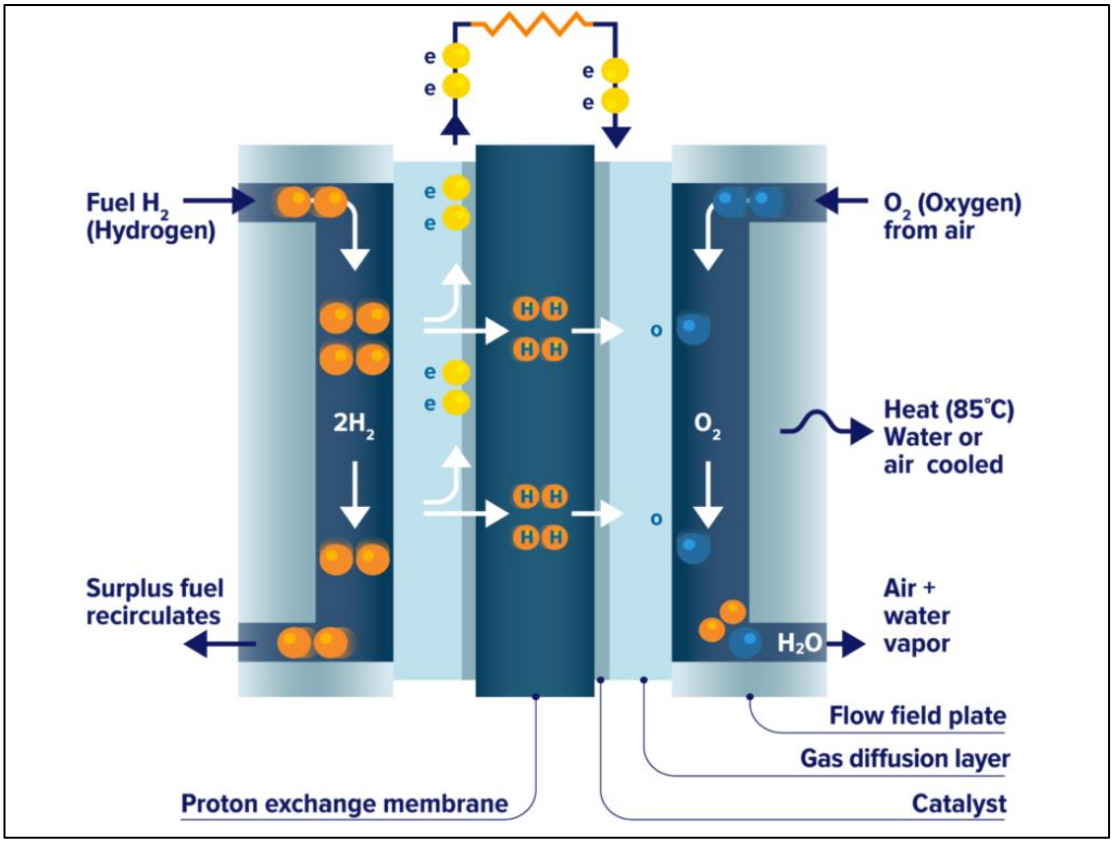

Figure 14. Schematic diagram of a fuel cell. Source : (CHFCA, 2016)

As mentioned earlier FCEBs have on board hydrogen storage tanks, in which hydrogen is compressed and stored to offer higher energy density and longer range. Also having on board hydrogen storage reduces the need for a larger battery pack and these battery backs are charged via electricity generated from fuel cells. However, despite their various advantages, FCEBs have a large upfront capital cost, and the hydrogen generating and refueling infrastructure also require significant capital investments.

2.7 Hydrogen Generation

Hydrogen has the potential to transform the US transportation sector. At room temperature, hydrogen is an odorless, colorless gas that typically exists in compounds with other elements such as oxygen (e.g., water). The energy in 1 kilogram of hydrogen (about 120 megajoules) gas is equivalent to the energy in 1 gallon of gasoline (about 121.3 megajoules) once it has been recovered and may be used as an energy carrier (like electricity) (EERE, n.d.-a). A variety of energy sources, including biomass, nuclear power, fossil fuels, and renewable energy sources, can be used to make hydrogen (Marchant, 2021). Various procedures can be used to accomplish this. Based on the hydrogen generation process and its carbon footprint, hydrogen can be classified into seven categories:

1. **Grey Hydrogen:** It is the most common form of hydrogen available currently and is generated through steam reforming from natural gas or methane. All the carbon emissions generated during this process are released into the atmosphere.
2. **Brown Hydrogen:** It is generated through gasification, where carbonous materials such as coal are converted into gas by heating. Such a process generates a large amount of carbon emissions (Enquiries, 2022).
3. **Yellow Hydrogen:** It is a fairly recent term referring to hydrogen created especially by electrolysis utilizing solar energy (Enquiries, 2022).

4. **Blue Hydrogen:** It is also generated using steam reformation, a procedure that employs steam to separate hydrogen molecules from natural gas, produces blue hydrogen. However, the majority of the carbon emissions from this process are sequestered or used for other purposes (Enquiries, 2022).
5. **Turquoise Hydrogen:** It is made through a method known as methane pyrolysis, which involves heating fossil fuels (such as methane) to such high temperatures that the fuel decomposes into hydrogen and solid carbon without releasing any carbon emissions (Enquiries, 2022).
6. **Pink Hydrogen:** It is also often known as purple hydrogen or red hydrogen, is produced by electrolysis. However, rather than being fueled by renewable energy, it is powered by nuclear energy (Enquiries, 2022).
7. **Green Hydrogen:** It is defined as hydrogen produced by separating water molecules in to hydrogen and oxygen through a process called electrolysis using renewable electricity (Chugh & Taibi, 2021)

SMR is also known as grey hydrogen, is the most common method of hydrogen generation today, due to the low capital investment in equipment, cheaper fuel cost (natural gas) and low energy requirements of hydrogen extraction. It is estimated that around 96% of the hydrogen consumed globally comes from traditional fossil fuels, which are classified as follows: 30% from naphtha reforming, 48% from natural gas steam reforming, and 18% from coal gasification (da Silva Veras et al., 2017). The next sections talk about the two most prominent methods of generating hydrogen, i.e., SMR and electrolysis.

2.7.1 Steam Methane Reforming (SMR)

The majority of hydrogen produced in the United States today is produced using SMR, a mature production process that uses high-temperature steam (700°C-1,000°C) to produce hydrogen from a methane source, such as natural gas. Methane reacts with steam under 3-25 bar pressure (1 bar = 14.5 psi) in the presence of a catalyst to produce hydrogen, carbon monoxide, and a small amount of carbon dioxide in steam-methane reforming (EERE, 2022). Steam reforming is endothermic, which means that heat must be supplied to the process for the reaction to take place (as shown in Equation 1 and Equation 2).

Equation 1. SMR reaction

$$CH_4 + H_2O\ (+heat) = CO + 3H_2$$

Equation 2. Water-gas shift reaction

$$CO + H_2O = C0_2 + H_2\ (+small\ amount\ of\ heat)$$

Conventional hydrogen production via steam methane reforming (SMR) is energy intensive, produces CO_2, and emits pollutants into the atmosphere. As a result, the environmental impacts of SMR hydrogen production must be quantified alongside the use-phase of FCEVs. About 8 to 12 kilograms (kg) of CO_2 are produced per kilogram (kg) of hydrogen produced (Blank & Molly, 2020). One kilogram of hydrogen is equivalent to one gallon of gasoline, which emits 9.1 kg of CO_2 when burned (EERE, n.d.-a).

SMR is the most economical pathway for generating hydrogen. However, GHG emissions from hydrogen synthesis by SMR utilizing natural gas are significant. CO_2 is the most abundant component of total emissions, accounting for 99% (by weight) of total emissions. CO_2 contributes 89.3% of the system's global warming potential (GWP), which is defined as the sum of CO_2, CH_4, and N_2O emissions expressed as CO_2-equivalent over a 100-year time period. Methane is responsible for 10.6% of the GWP (Spath & Mann, 2000). Figure 15 shows the amount of GHG emissions from this process, excluding CO_2.

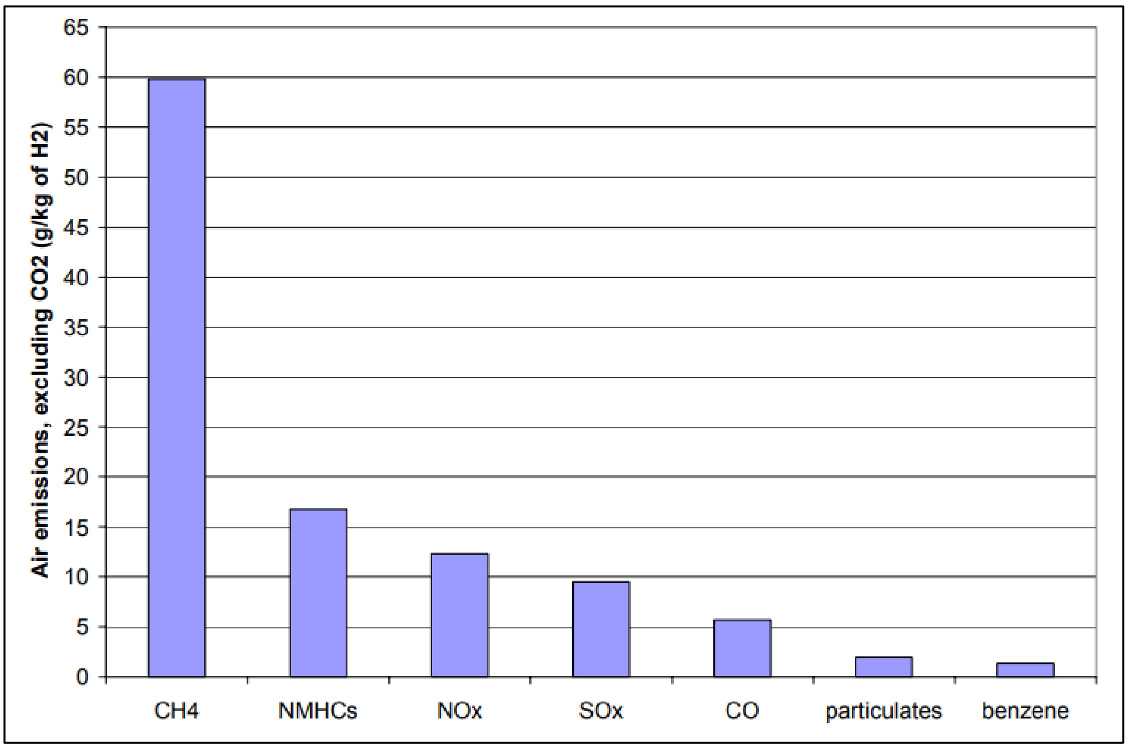

Figure 15. SMR GHG emissions excluding CO_2. Source: (Spath & Mann, 2000)

2.7.2 Electrolyzer

Electrolysis has proven to be a more environmentally friendly method for generating hydrogen. The process of splitting water into hydrogen and oxygen using electricity is known as electrolysis. This reaction takes place in a device known as an electrolyzer (as shown in Figure 16 below). Electrolyzers can range in size from small, appliance-sized equipment suitable for small-scale distributed hydrogen production to large-scale, central production facilities that could be directly linked to renewable or other non-greenhouse-gas-emitting forms of electricity generation.

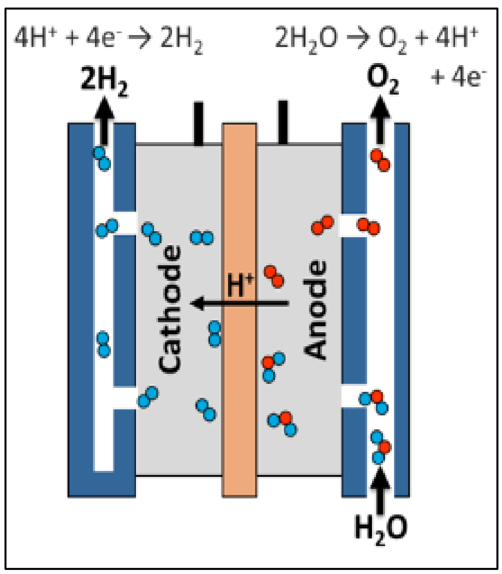

Figure 16. Schematic diagram of the electrolysis process. Source: (EERE, 2022)

If the electricity utilized in the electrolytic process comes from renewable sources, such as solar or wind, the hydrogen produced is known as green-hydrogen and has no GHG emissions other than the emissions associated with the manufacturing of the electrolyzer. This is a more environmentally friendly alternative than SMR. However, because this is a novel technology, it has a greater overall cost.

Different electrolyzers work in different ways, owing to the various electrolyte materials used and the ionic species they conduct (EERE, 2020). The three most used electrolyzers today are:

1. Polymer Electrolyte Membrane (PEM) Electrolyzers: PEM electrolyzers (shown in Figure 17 below) employ a proton exchange membrane in conjunction with a solid polymer electrolyte. Water splits into hydrogen and oxygen when current is delivered to the fuel cell stack, and the hydrogen protons flow through the membrane to generate H_2 gas on the cathode side (Cummins INC., 2020). These type of electrolyzers have an efficiency between 74% to 87% (Hamdan et al., 2013)

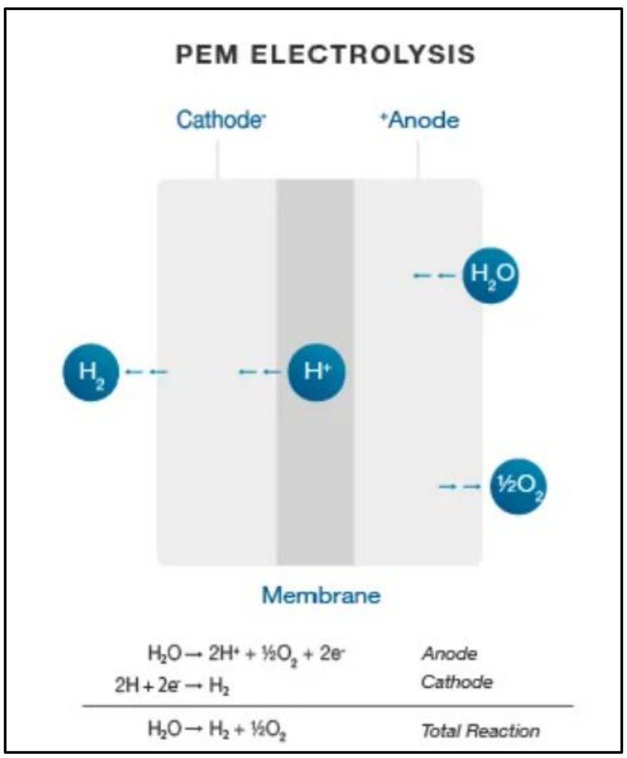

Figure 17. PEM electrolyzer diagram. Source: (Cummins INC., 2020)

2. Alkaline Electrolyzers: A liquid electrolyte solution, such as potassium hydroxide (KOH) or sodium hydroxide (NAOH), and water are used in an alkaline electrolyzer (shown in Figure 18 below). The hydrogen is created in a "cell" made up of an anode, a cathode, and a membrane. The cells are generally connected in a "cell stack," which generates more hydrogen and oxygen as the number of cells grows. When current is given to the cell stack, hydroxide ions (OH-) flow through the electrolyte from the cathode to the anode of each cell, generating hydrogen gas bubbles on the cathode side and oxygen gas at the anode, as seen above (Cummins Inc., 2020). The efficiency of an alkaline electrolyzer varies between 65% to 67% (Knop, 2022).

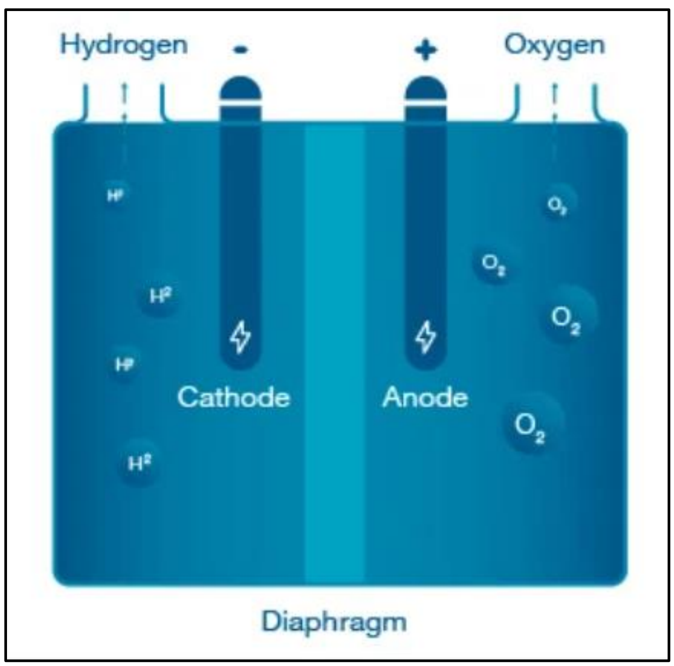

Figure 18. Alkaline Electrolyzer diagram. Source: (Cummins INC., 2020)

3. Solid Oxide Electrolyzers (SOEC): The electrolyte is made of solid ceramic material. At the cathode, electrons from the external circuit interact with water to generate hydrogen gas and negatively charged ions. The oxygen then travels through the slid ceramic membrane and interacts with the anode to produce oxygen gas and electrons for the external circuit. SOECs (shown in Figure 19 below) operate at substantially greater temperatures (over 500 degrees Celsius) than alkaline and PEM electrolyzers (up to 80 degrees Celsius) and have the potential to be much more efficient than PEM and alkaline electrolyzers (Cummins INC., 2020). A SOEC electrolyzer can produce hydrogen at 90% efficiency (Fuel Cell Energy, 2023).

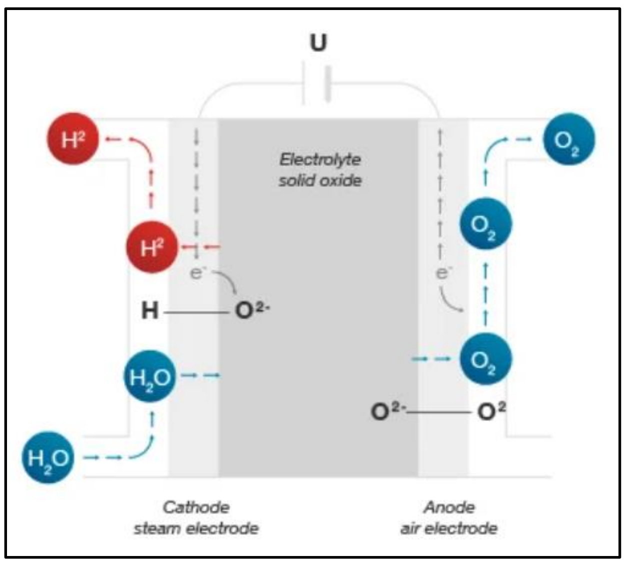

Figure 19. Solid-oxide electrolyzer diagram. Source: (Cummins INC., 2020)

Once the hydrogen is generated by the electrolyzer it is collected at the cathode outlet, concentrated, and cleaned of impurities before being stored in high pressure hydrogen storage tanks. As hydrogen is gaseous at atmospheric pressure and would take up a lot of space if stored as such, therefore hydrogen is compressed and refrigerated to increase its energy density and is stored as liquid hydrogen. The process of generating and storing hydrogen is shown in Figure 20.

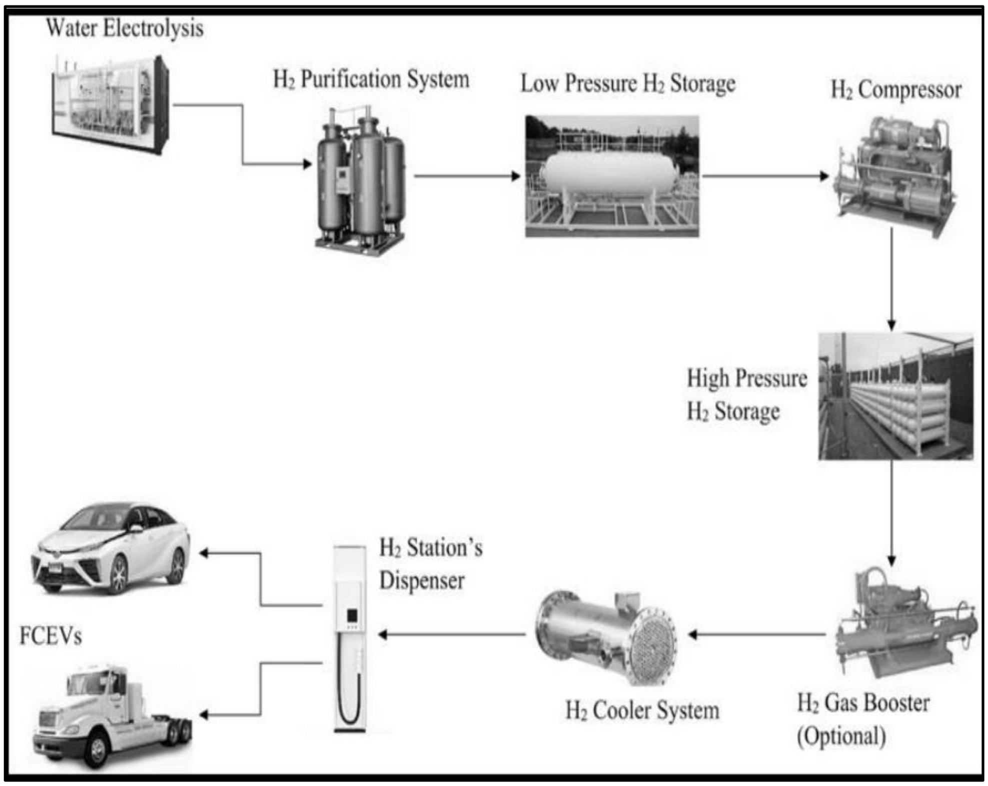

Figure 20. Electrolytic hydrogen generation and storage. Source: (D. Apostolou & G. Xydis, 2019)

2.7.3 Hydrogen Refueling Station

Hydrogen refueling stations (HRS) consist of hydrogen dispensers and other equipment to ensure the safety and quick refueling of FCEV. A typical HRS is made up of hydrogen storage tanks, hydrogen gas compressors, a pre-cooling system, and a hydrogen dispenser that dispenses hydrogen at pressures of 350 bar, 700 bar, or dual pressure dispensing depending on the kind of vehicle being refueled. A conventional hydrogen automobile will take three minutes to refill, whereas a bus will take seven minutes (Haskel, 2022). Currently there are 105 HRS in California, as shown in Figure 21 (California Energy Commission, 2023) .

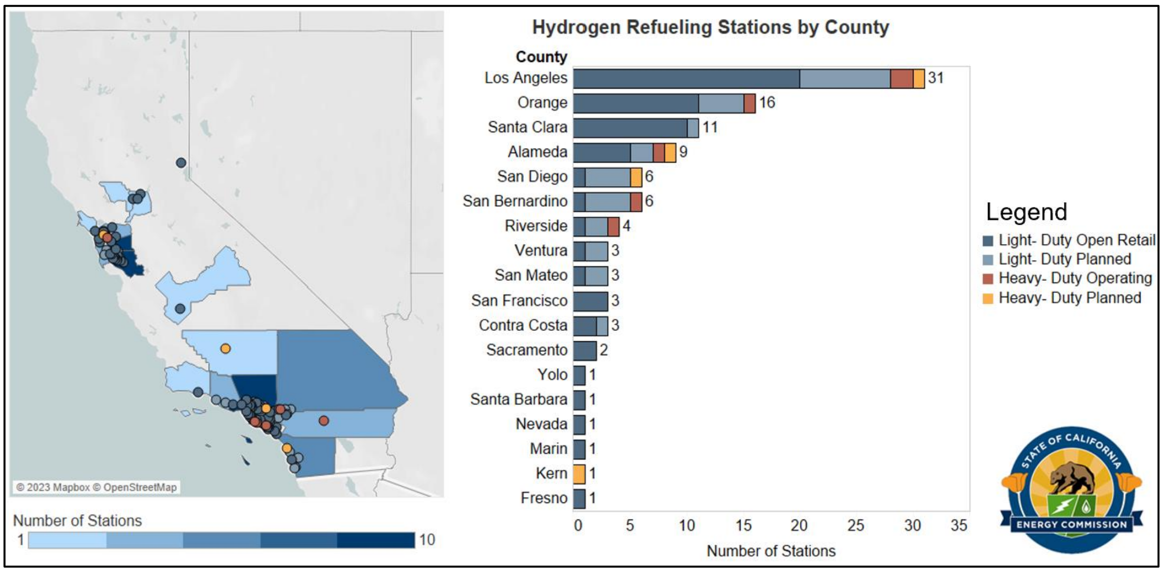

Figure 21. Hydrogen Refueling Stations in California. The bar chart reads left to right: Light-Duty Open Retail, Light-Duty Planned, Heavy-Duty Operating, and Heavy-Duty Planned. Source: (California Energy Commission, 2023)

As stated earlier, hydrogen production can be carried out either on-site or off-site, depending on the daily demand. In the case of off-site production, hydrogen is transported to the desired location would also require the use of carbon-free fuels in the vehicles or pipelines involved. For onsite production, hydrogen can be generated onsite through electrolyzer and then be stored for use at desired time. A hydrogen refueling station requires the following components shown in Figure 22 (Apostolou & Xydis, 2019) :

1. Production unit (On-site electrolyzer/off-site production)

2. Purification unit: To meet the required standards for fuel cell supply, hydrogen must undergo purification to achieve a purity level of above 99.97%.
3. A low-pressure hydrogen storage tank is necessary to facilitate storage.
4. A high-pressure compressor unit is required to elevate the pressure from 350 to 700 bar to enable storage in high-pressure storage tanks located inside the station's main hydrogen storage tanks.
5. High-pressure storage tanks are necessary to store compressed hydrogen gas.
6. A hydrogen compressor is necessary to achieve the pressure required to deliver hydrogen to the storage system of the bus.
7. A refrigeration unit is required to maintain the hydrogen temperature at -40°C to ensure safety.
8. The mechanical and electric equipment required includes piping, control panels, high-voltage connections, sensors, and safety valves.
9. A dispenser unit is required to refill empty vehicles with hydrogen.

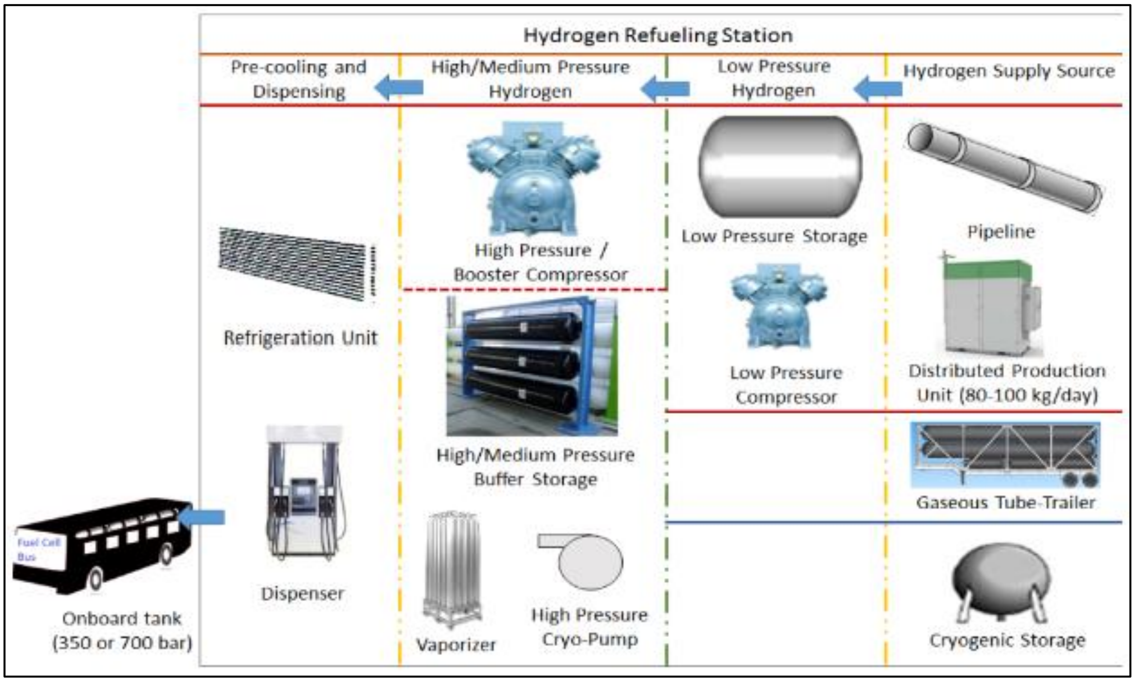

Figure 22: Hydrogen refueling station layout. Source: (Argonne National Lab., 2017)

The LCOH is a widely used metric for comparing the costs of different hydrogen production methods. It takes into account all of the costs associated with producing hydrogen over the lifetime of the system, including capital expenditures, operational expenditures, and maintenance costs, and divides these costs by the amount of hydrogen produced.

In this study, the LCOH has been calculated by considering only the extra equipment required for on-site electrolytic hydrogen production. This means that the capital expenditure costs of an electrolyzer, as well as solar PV and battery systems, have been factored in when determining the LCOH. This approach has been taken because on-site electrolytic hydrogen production requires additional equipment that is not needed if HTA procures commercially available hydrogen from other sources.

CHAPTER 3. METHODS

This chapter describes the methodology, assumptions and scenarios used to calculate the LCOH production to fuel the upcoming FCEB fleet of HTA. As mentioned earlier, this thesis calculates the LCOH for generating 300 kg to 750 kg of hydrogen daily over the timeline of 8 years (as shown in Table 1) with a range of possible scenarios. This model also has a provision to choose the utility rate structure for generating on-site electrolytic hydrogen, as described later in this section, and to provide results that are further used to make a recommendation regarding which system sizing is the most cost-effective solution for HTA. All calculations were performed in a spreadsheet model. The various scenarios evaluated using this model are shown in Table 5 below.

This study calculates the LCOH based on the amount of daily hydrogen required, as mentioned earlier, and the utility rate structure chosen to procure electricity from the grid. Three rate structures have been considered, each of which enables HTA to procure 100% renewable electricity from the PG&E grid. Procuring 100% renewable electricity from the grid allows HTA to maximize the LCFS credit generation and secure the maximum subsidy, i.e., \$3 per kg of hydrogen, under the IRA legislation signed into law by President Biden as mentioned earlier.

3.1 Introduction to the model

The primary goal of this thesis is to determine the Levelized Cost of Hydrogen (LCOH) and to characterize the necessary apparatus, system dimensioning, capital expenditure, operational expenses, and other pertinent operational factors for producing on-site green hydrogen. This analysis will culminate in recommendations on whether it is more economical for the HTA to acquire hydrogen from a commercial supplier, in this case Air Products, or to establish an in-house hydrogen generation facility. The general framework of the model for calculating LCOH using the B-20 + E-GT & BEV + E-GT utility rate structure is shown in Figure 23.

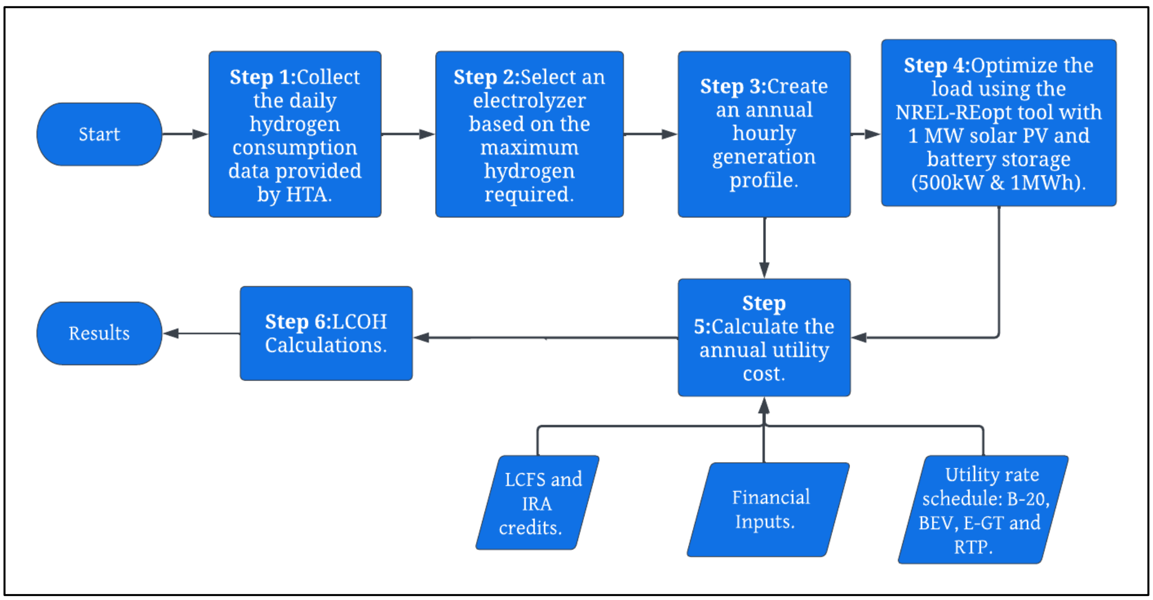

Figure 23. General Framework for the model for B-20 and BEV utility Rate structures

The thesis model takes a different approach for calculating LCOH when electricity is procured at RTP. The study examines the potential impact of RTP on LCOH if changes are made to policies to allow retail consumers to purchase electricity at RTP, with a focus on the generation of green hydrogen. For this study, a baseline monthly demand charge of $25 per monthly peak load (kW) is assumed to assess the impact of demand charges. This demand charge has been assumed as similar demand charges are applicable in B-20 commercial utility rate structure. Furthermore, a supporting sensitivity analysis has been conducted to assess the impact of varying RTP demand charges on LCOH. While it's technically possible to make a policy change to expose hydrogen production to RTP without demand charges, it's not a common practice among utilities. Additionally, a sensitivity analysis is performed to evaluate the impact of different demand charges on the LCOH and determine at what demand charge the LCOH becomes competitive with hydrogen generated through SMR. Furthermore, no solar PV and battery system is considered for the scenario when RTP is used, as no ToU exists in RTP, and hydrogen is only generated in the hours when electricity prices are at the lowest and this analysis would be beyond the scope of this thesis as REopt tool does not allow do compute solar PV and battery sizing without a utility rate structure.

The primary input for this study is the daily demand for hydrogen in kilograms during the expected 15-year lifespan of the electrolyzer. This data is used to determine which electrolyzer to use, with NEL providing two options: the MC 250 and the MC 500. NEL is a Norwegian-based company that specializes in the production, storage, and distribution of hydrogen fuel. The company has a global presence and is a leading provider of complete hydrogen solutions for various industries, including transportation, energy, and industrial applications. The electrolyzer is chosen based on the daily hydrogen requirement, with the MC 250 able to generate 531 kilograms of hydrogen per day, or roughly 22 kilograms per hour, and the MC 500 able to produce 1062 kilograms of hydrogen per day or approximately 44 kilograms per hour. Since the hydrogen demand of the HTA is expected to exceed the production capacity of the MC 250 after five years, the study assumes that the MC 500 is the better option from the start. Additionally, the study examines the possibility of oversizing the electrolyzer to generate the necessary daily hydrogen while avoiding peak utility hours, which have higher demand charges, to decrease the levelized cost of hydrogen. Therefore, based on these factors, the MC 500 is the ideal candidate for this analysis.

It is also important to note that LCFS credits are earned as revenue based on energy delivered as ($/kg) of hydrogen fuel for FCEBs. The LCFS credits are calculated based on CARB’s 2022 calculator. To compute the cost of establishing an on-site hydrogen production facility, a database was constructed to aid the model (CARB, 2023b). This database was populated with information from diverse sources, which was then utilized to generate multiple inputs such information related to electrolyzers, rate structure, common financial inputs, etc. In Section 3.2, a thorough analysis of these inputs is presented.

It's worth mentioning that this model can provide results by altering the database, such as such as choosing different types of electrolyzers, hourly hydrogen production, utility rates, and sizing of solar panels and batteries. To find the best and most cost-effective option for HTA, various combinations of these options were analyzed and the combination yielding the least LCOH is presented in the results section. Also, it's important to remember that the LCOH calculated by the model only includes costs associated with hydrogen production, not storage or refueling. These latter costs would be the same whether HTA produces the hydrogen on-site or buys it from Air Products.

3.2 Model parameters and Data sources

This section describes the database developed to support the model, the application of database in the model calculations to determine the associated cost, and the methods used to calculate LCOH. The database created for the model includes information related to daily hydrogen requirements, technical and economical specifications for electrolyzers and hourly hydrogen production and load profiles, along with data gathered from the REopt tool, NREL reports, and other literature related to hydrogen generating infrastructure. The model works on user-provided inputs that include some metrics that are in common and others that are technology specific. This section describes the common and technology-specific datasets separately in the following subsections.

3.2.1 Daily Hydrogen Consumption

As indicated earlier, the model necessitates certain user-specified inputs to function effectively. One of the primary inputs required by the model is the daily hydrogen consumption target over the electrolyzer's lifespan. To obtain this crucial data, a database was created based on the hydrogen consumption targets provided by HTA for the subsequent 8 years. This database will serve as a fundamental component of the model. Refer to Table 1 for the daily hydrogen consumption targets for each year.

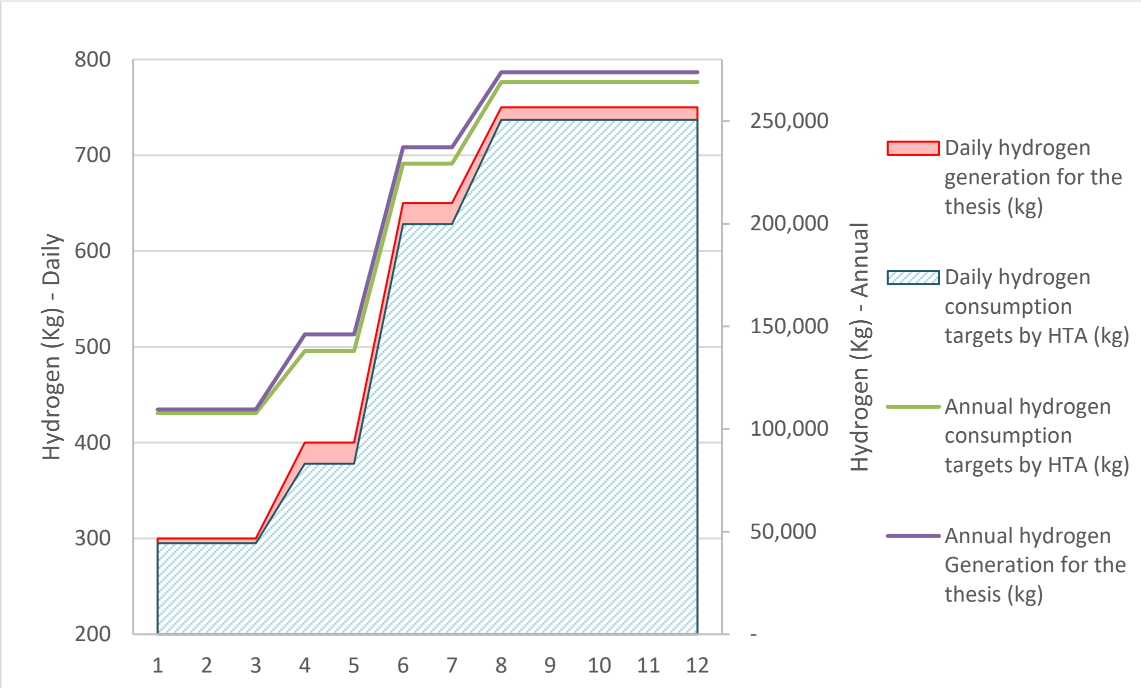

Figure 24. Hydrogen targets vs generation

To simplify the analysis, the daily intake of hydrogen in this study has been approximated to the nearest 50 kg threshold. For instance, during the initial triennial period, the aimed intake amounts to 295 kg while the production target is 300 kg, as shown in Figure 24. This approach is adopted to simplify the model and to take into account any losses that could transpire throughout the production process.

3.2.2 Utility Rate Structure

As indicated in section 2.7.2, electrolysis is a highly energy-intensive process that necessitates a significant amount of electricity for hydrogen production. For an electrolyzer system with an efficiency of 78%, the generation of one kilogram of hydrogen via electrolysis requires roughly 50 kWh of electricity (Ivy, 2004). Hence this thesis analyzes various rate structures to assess their impact on the LCOH. The utility rate structures used for this study are as follows:

1. B-20 (T): If a client's peak demand surpassed 999 kW for at least three consecutive months in the previous 12 months, the consumer is qualified for service under schedule B-20. (Kenney, 2021). Details regarding the rate structure are provided in Appendix A.
2. BEV-2: Business Electric Vehicle (BEV) is an optional schedule that applies to business EV charging, in which non-EV commercial consumption and EV charging usage are metered separately. The BEV rate is divided into two unique rate options: BEV-1 and BEV-2. Customers with electric power use of 100 kW or less are eligible for the BEV-1 tariff option. Customers with kW use of 100 kW or more are eligible for the BEV-2 (Allen, 2020). Details regarding the rate structure are provided in Appendix A.
3. Real Time Electricity pricing: RTP is the price charged to customers that closely match either the underlying wholesale electricity market or the utility's cost of production (EERE, n.d.-b). The real time pricing changes every hour, and the future projections for RTP have been obtained from California Public Utilities Commission's (CPUC) "Avoided Cost Calculator" model (CPUC, 2022). Retail consumers cannot avail RTP, but RTP with a hypothetical demand charge of $25 for monthly peak load (kW/peak monthly load) has been used to calculate the LCOH as a hypothetical exercise to assess the impact of exposing hydrogen generation to RTP.

Additionally, the Electric Green Tariff (E-GT) rate supplement is also used along with the B-20 and BEV-2 rate structure. E-GT is one of two optional rate supplements given by the Green Tariff Shared Renewables (GTSR) scheme to customers otherwise applicable rate schedules. The Green Tariff option allows customers to purchase renewable power in amounts ranging from 50% to 100% of their total electric use (Kenney, 2020). Using B-20 and BEV rate structure along with E-GT ensures that all the electricity being consumed from the grid for hydrogen generation is renewable energy and that hydrogen generated has minimum carbon emissions associated with it.

Table 5. Scenarios evaluated in this thesis.

Daily Hydrogen Requirement
Year 1 to 3: 300 kg daily Year 4 to 5: 400 kg daily Year 6 to 7: 650 kg daily Year 8 onwards: 750 kg daily
Scenario 1: Business as usual (BAU)
LCOH with B-20 (T) + E-GT utility rate structure
LCOH with BEV-2 (T) + E-GT utility rate structure
LCOH with real time electricity pricing
Scenario 2: With assistance from Solar PV & Battery
LCOH with B 20 (T) + E-GT utility rate structure
LCOH with BEV-2 (T) + E-GT utility rate structure

3.2.3 Electrolyzer Cost

According to the daily hydrogen requirement, two PEM electrolyzers, produced by NEL hydrogen, have been chosen for evaluation of hydrogen generation in this model. As described in earlier sections, PEM electrolyzers present higher efficiency in comparison to alkaline electrolyzers and are less expensive than SOEC electrolyzers. The electrolyzers used for the analysis are:

1. MC 500: A 2.5 MW electrolyzer with daily (24 hrs.) hydrogen production capacity of 1062 kg.
2. MC 250: A 1.25 MW electrolyzer with daily (24 hrs.) hydrogen production capacity of 531 kg.

The specification for both the electrolyzers are provided in

Table 6 below. The M-class on-site hydrogen generator is fully automated, utilizing a modular containerized configuration for simplified installation and integration. It features tri-mode operations, allowing for versatile functionality (NEL, 2020):

1. Command-following mode allows operation based on available input power.
2. Load following mode automatically adjusts output to match demand.
3. Tank filling mode operates with power-conservation mode during standby.

Table 6. Nel Electrolyzers Specification. Source (NEL, 2020) & (Weaver, 2022)

Model	MC250	MC500
Class	1.25 MW	2.5 MW
Cost	$2.9 Million	$ 3.7 Million
Type	PEM	PEM
Average Power consumption at stack per volume of H_2 gas produced	4.5 kWh/Nm^3	4.5 kWh/Nm^3
Hourly hydrogen generation capacity by mass (kg/hr)	22.125	44.25
Maintenance Cost	2% of CapEx	2% of CapEx
Installation Cost	$100,000	$100,000

As previously mentioned, the MC500 has been chosen for analysis in this thesis for two reasons. Firstly, it can generate the necessary amount of daily hydrogen. Secondly, it has been oversized to avoid generating hydrogen during peak demand hours, which helps to keep the levelized cost of hydrogen low.

3.2.4 Hourly Hydrogen Generation Profiles

Hourly hydrogen generation profiles were established, taking into account the daily hydrogen production targets, utility rate structure, and the chosen electrolyzer. Different ToU hours in the utility rate structure were given a score ranging from 1 to 3 based on the demand charges, as shown in Table 7, Table 9 and Table 9.

Table 7. ToU periods for B20 utility rate structure for summer season (June-September). Source: (Kenney, 2021)

ToU	Time	Score
Peak:	4:00 to 9:00 pm	1
Partial-Peak:	2:00 pm to 4:00 pm AND 9:00 pm to 11:0 pm	2
Off-Peak:	All other hours	3

Table 8:ToU periods for B20 utility rate structure for winter season (October-May). Source: (Kenney, 2021)

ToU	Time	Score
Peak:	4:00 to 9:00 pm	1
Super Off-Peak:	9:00 am to 2:00 pm	3
Off-Peak:	All other hours	2

Table 9. ToU periods for BEV-2 utility rate structure for the whole year. Source: (Allen, 2020)

ToU	Time	Score
Peak:	4:00 pm to 9:00 pm	1
Off-Peak:	9:00 pm to 9:00 am And 2:00 pm to 4:00 pm	2
Super Off-Peak:	9:00 am to 2:00 pm	3

In the time intervals assigned a score of 3, the highest hourly hydrogen output is achieved, while the remaining hydrogen is generated during time intervals with a score of 2. To minimize the costs associated with high demand and energy charges, every effort is made to avoid hydrogen generation during time intervals assigned a score of 1. For detailed hourly hydrogen generation profiles see Appendix B.

RTP is an energy pricing technique in which the price of power adjusts according to the grid's actual demand and supply situations. Electricity costs are normally greatest during the afternoon and early evening hours, when energy consumption is at its peak, under California's RTP system. Rates might be two to three times higher during these peak hours than during off-peak hours.

Hourly RTP projections for the NP-15 CAISO node were collected from the avoided cost calculator (ACC) for the next 15 years (CPUC, 2022). The model provided hourly pricing for each year (from 2024 to 2039). Figure 25 shows RTP for the years 2024 to 2028.

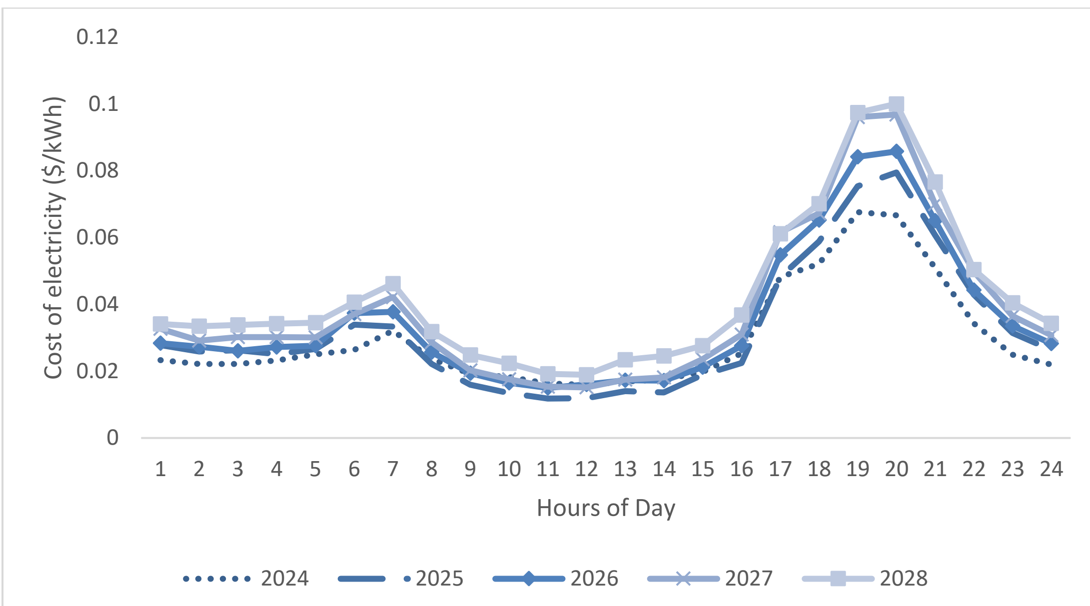

Figure 25: Hourly RTP for NP-15 electricity price node. Source: (CPUC, 2022)

To establish an hourly hydrogen generation profile for the RTP scenario, the hourly averages for each year's RTP were computed annually. These calculations enabled the identification of the hours when prices are at their lowest and highest points throughout the day. During the periods when the RTP values are at their lowest, hydrogen generation is maximized to produce the necessary quantity of hydrogen. Conversely, when the RTP values are highest, hydrogen generation is limited to meet the daily hydrogen requirements and minimize costs. Pricing for node NP-15 was selected as it covers the north California area as shown in Figure 26. More details are provided in Appendix B.

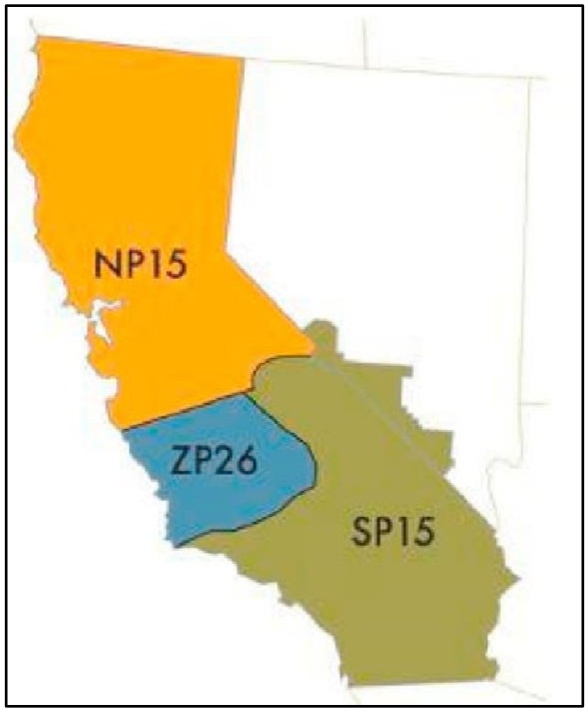

Figure 26. CASIO price zone map. Source: (Westgaard et al., 2021)

3.2.5 Low carbon Fuel Standards (LCFS)

California's LCFS creates an additional revenue stream for the producers of low-carbon fuels. In this study, the calculation of LCFS credits for FCEBs is based on the year 2023. Nevertheless, it is important to note that LCFS credit values are subject to potential changes over time. Information regarding LCFS credits used for this study are listed in Table 10. These inputs were generated using the LCFS 2022 credit calculator designed by CARB (CARB, 2023a).

Table 10. LCFS credits for FCEB from 2023 – 2038. Source: (CARB, 2023b)

Year (2023 - 2038)	Credit	Score	Fuel Switch	Energy Economy Ratio	Credit Price ($/metric ton of CO_2e)
FCEBs	1.38 $/kg H_2	LCFS credit calculator	Diesel to Hydrogen	1.20	63

Additionally, as the LCFS credit prices can change over time, a sensitivity analysis has been done to assess the impact of LCFS credit prices ranging from $63 to $200 per metric ton of CO_2e on the LCOH.

3.2.6 Other key model parameters

This section contains information about the basic financial and technical parameters regarding the factors and technologies used to support this study, as shown in Table 11 below.

Table 11. Common input and assumptions used in the model.

Description	Units	Qty	Source
Capex cost of Solar and Battery	$/kW-DC	$1,970	(Ramasamy et al., 2021)
Solar O&M cost	($/kW-DC per year)	$ 17	(NREL, 2023)
Inflation Reduction Act incentive	$/kg of hydrogen	$ 3	(Collins, 2021)
Discount Rate	(%)	5%	
Labor cost for system operations	% of electrolyzer capex	2%	

3.2.7 NREL-REopt analysis

Renewable Energy Integration and Optimization (REopt) is a software application developed by NREL with the aim of supporting energy systems design and operation in both commercial and residential buildings. The tool assesses the economic and technical feasibility of diverse renewable energy and energy storage technologies, and subsequently determines the optimal system configuration that minimizes costs while meeting pre-established performance objectives. Furthermore, REopt offers guidance on incentivization and financial strategies that can help project implementation. Notably, the study examines various scenarios that identify pathways for hydrogen production, specifically by assessing the effectiveness of solar photovoltaic (PV) systems and batteries in reducing grid electricity loads. Through the utilization of REopt, an analysis of the baseline hourly annual load is conducted. Subsequently, the tool optimizes the load using solar PV and batteries and based on utility rate structure's ToU profile, thus providing an optimal annual hourly load profile. The REopt software generates an hourly load profile for the grid after integrating a 1 MW solar PV array, and a 500 kW-1 MWh battery backup system. This hourly load profile is then used to calculate the annual utility cost that HTA has to bear for operating the electrolyzer. Compared to the base case, the integration of solar PV and a battery system reduces the load on the grid, resulting in lower annual utility costs for HTA. Figure 27 shows the steps involved in REopt analysis.

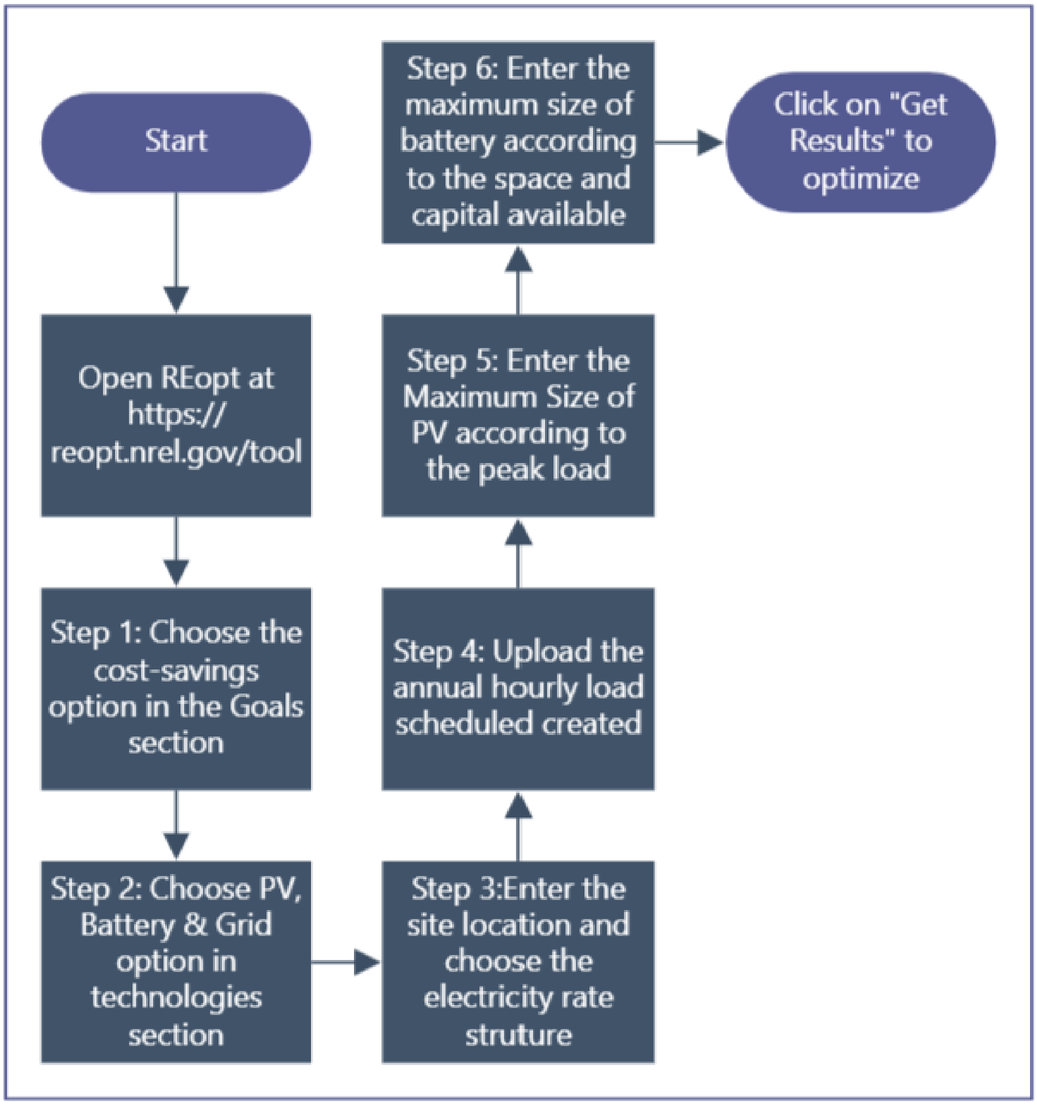

Figure 27. Steps for REopt analysis. Source: (NREL, 2023)

3.3 Economic Analysis

Based on the common inputs and data from database as mentioned above, the model calculates the LCOH. During the initial triennial period, a daily production rate of

300 kgs of hydrogen is targeted, which increases to 400 kgs for the subsequent biennial period. For the two-year period encompassing the sixth and seventh years, the daily hydrogen generation target is 650 kgs, which then increases to 750 kgs from the eighth year onward.

The model possesses the capability to compute the LCOH for a range of permutations, such as diverse combinations of solar PV and battery sizing, hourly hydrogen production profiles, utility rate structures, various incentives, equipment capital, maintenance and operation cost, and, labor cost. The detailed calculations are discussed in the following section. As stated above, the objective of the model is to identify the most cost-effective combinations of all feasible technologies and economic alternatives.

3.3.1 Annual Utility Cost Calculation

(A) For utility rate structure: First, the yearly utility expenditure is determined by utilizing the designated utility rate structure. The utility cost comprises three major components, the demand cost, energy cost, and meter cost, which are estimated through Equation 3, Equation 4 and Equation 5 respectively. The monthly and annual energy cost is calculated using Equation 6 and Equation 7 respectively.

Equation 3. ToU demand cost

$$\begin{aligned} ToU\ Demand\ Cost\ (\$) \\ &= 15\ min.peak\ load\ (kW)\ in\ ToU \\ &* demand\ charge\ in\ that\ ToU\ (\frac{\$}{kW}) \end{aligned}$$

Equation 4. ToU energy cost

$$\boldsymbol{ToU\ Energy\ Cost}\ (\$) = \boldsymbol{Total\ energy\ comsumed\ (kWh)\ in\ ToU} * \boldsymbol{energy\ charge}\ (\frac{\$}{\boldsymbol{kWh}})\ \boldsymbol{in\ that\ ToU}$$

Equation 5. Meter cost

$$Meter\ Cost\ (\$) = Number\ of\ days\ in\ the\ month * customer\ charge\ (\frac{\$}{day})$$

Equation 6. Monthly utility cost

$$Monthly\ utility\ cost\ (\$) = All\ ToU\ demand\ cost(\$) + All\ ToU\ energy\ cost(\$) + Meter\ cost(\$)$$

Equation 7. Annual energy cost

$$Annual\ energy\ cost\ (\$) = \sum_{Jan}^{Dec} Monthly\ utility\ cost$$

By applying the previously described equations and methodology, the utility cost is evaluated for all the specified daily hydrogen production targets for B-20 and BEV utility rate structures.

<u>(B) For Real Time Pricing (RTP):</u> The study aims to analyze the potential influence of RTP on LCOH in the context of green hydrogen generation. The findings of this analysis will facilitate the evaluation of LCOH if utility policies are amended to authorize retail consumers to obtain electricity based on RTP for hydrogen generation purposes. Two components make up the annual electricity cost for RTP:

1. Energy Cost: The energy charges are calculated by multiplying the hourly energy load (kWh) as discussed in section 3.2.4 with the hourly RTP energy cost obtained from the ACC model ($/kWh). This calculation provides the cost of the electricity needed to produce the hydrogen during each hour of the day, as shown in Equation 8.

Equation 8. RTP Energy Cost

$$Energy\ Cost\ (\$) = Hourly\ energy\ load\ (kWh) * hourly\ RTP\ enrgy\ cost\ \left(\frac{\$}{kWh}\right)$$

2. Demand charges: As mentioned above in section 3.2.2, the model assumes a baseline monthly demand charge of $25 on the peak load ($/peak kW), even though no demand charges are associated with RTP of electricity. Additionally, a sensitivity analysis has been performed to evaluate the effect of different demand charges on the LCOH. The demand charge is calculated using Equation 9 and the sensitivity analysis is further discussed in Chapter 4.

Equation 9. RTP Demand Charge

$$Demand\ Charge\ (\$) = Monthly\ peak\ load\ (kW) * \$25(\frac{\$}{monthly\ peak\ kW})$$

The annual energy charge is the sum of all the monthly RTP energy cost and monthly RTP demand charges, as shown in Equation 10 and Equation 11.

Equation 10. Monthly RTP utility charges

$$Monthly\ Utility\ cost\ (\$) = RTP\ energy\ cost + RTP\ demand\ charges$$

Equation 11. Annual RTP utility charges

$$Annual\ energy\ cost\ (\$) = \sum_{Jan}^{Dec} Monthly\ utility\ cost$$

3.3.2 Equipment Maintenance Cost

To maintain a PEM electrolyzer, it is important to ensure that the water used is of high purity, the membrane is periodically cleaned, the electrodes are inspected and cleaned, and the system is periodically purged with gas. Water management, stack maintenance, and safety devices should also be monitored and checked regularly. The specific requirements may vary depending on the manufacturer and model, so it is important to follow the manufacturer's instructions and maintenance schedule to keep the PEM electrolyzer operating safely and efficiently. Maintenance cost per year for the electrolyzer is considered to be 2% of the capex cost (as shown in Equation 12) (Weaver, 2022).

Equation 12. Electrolyzer Annual Maintenance Cost

$$Electrolyzer\ annual\ maintenace\ cost\ (\$/year) = 2\% * Capex\ cost\ of\ electrolyzer\ (\$)$$

Solar PV systems also necessitate maintenance, as the panels require regular cleaning to prevent the settling of dust particles, which can cause a decrease in panel efficiency. A maintenance cost $17 per kW-DC per year is considered for the model (NREL, 2023). Equation 13 is used to calculate the annual maintenance cost.

Equation 13. Solar PV Annual Maintenance Cost

$$Solar\ PV\ system\ annual\ maintence\ cost\ (\$/year)$$
$$= \frac{\$17}{(kW - DC)} * Solar\ PV\ DC\ name\ plate\ capacity\ (kW - DC)$$

3.3.3 Labor Cost

HTA would need to employ skilled personnel to supervise and monitor the electrolyzer system. The labor cost is estimated at 2% of the electrolyzer capital expenditure (capex) (Steward, 2009). Equation 14 is used to calculate the labor cost.

Equation 14. Labor Cost

$$Labor\ Cost\ \left(\frac{\$}{year}\right) = 2\% *\ Electrolyzer\ Capex(\$)$$

3.3.4 LCFS credit calculator

As previously mentioned, the LCFS is a regulatory mechanism designed to encourage the adoption of low carbon-emitting fuels and associated technologies in the transportation sector. The policy is consistent with the state's objectives to decrease carbon intensity. As part of ZEV technology, hydrogen fuel cell buses are eligible for LCFS credits, which are based on the number of miles driven by the FCEBs. Revenue generated from the sale of credits can be utilized to offset expenses associated with the deployment and operation of the buses. The LCFS credit calculator provided by the CARB is utilized to compute the LCFS credit (CARB, 2023b). The following assumptions are considered while operating the calculator.

- Vehicle Fuel EER[1] = 1.9[2] (Hydrogen used in a Heavy-Duty Fuel Cell Vehicle)
- Carbon Intensity = 10.51 g CO_2e/MJ 100% renewable electricity (solar PV) (CARB, 2023b) & 164.46 g CO_2e/MJ for electricity from grid in case of RTP (Englander, 2022)
- Credit price per metric ton of CO_2e: $63 (Smith, 2020) (NESTE, 2017)
- Switching fuel: Diesel to Hydrogen

The CARB calculator is used to calculate the per-mile credit, which is $1.20/kg of hydrogen consumed or $0.04/kg of hydrogen for real time pricing electricity. The LCFS credit for hydrogen produced through RTP is low because the CI score for grid electricity is higher, 164.46 g CO_2e/MJ compared to 100% renewable electricity. This factor is used to determine the annual LCFS revenue (as per Equation 15) that FCEBs will generate after their commencement annually.

Equation 15. Annual LCFS revenue

$$Annual\ LCFS\ reveneue(\$) = LCFS\ credit\ \ (\$/kg) * Annual\ hydrogen\ generated\ (kg)$$

When hydrogen is produced using all renewable electricity, a $1.20 LCFS credit per kilogram of hydrogen is applied. On the other hand, when hydrogen is generated

[1] The Energy Economy Ratio (EER) refers to the distance that can be traveled by a vehicle using alternative fuel, divided by the distance that can be traveled by an internal combustion engine vehicle while consuming the same amount of energy (CARB, 2023a).

[2] The fuel economy of different cars varies. The EER rewards efficient cars for conventional fuel displacement caused by the use of clean vehicles (CARB, 2023a).

using Real-Time Pricing (RTP) and electricity from California's grid, a $0.04 LCFS credit per kilogram of hydrogen is used.

3.3.5 Inflation Reduction Act Tax Credit

As part of the Inflation Reduction Act (IRA), Section 13204 has introduced a new tax credit for the production of qualified clean hydrogen over a period of ten years. To qualify for the credit, the hydrogen must be produced through a process that results in a low lifecycle greenhouse gas emissions rate, specifically not greater than 4 kilograms of CO_2e per kilogram of hydrogen (Rep. Yarmuth, 2022). This definition of "qualified clean hydrogen" sets a clear standard for producers to strive towards and incentivizes the development of sustainable and environmentally friendly hydrogen production processes. By providing a tax credit for the production of qualified clean hydrogen, the IRA supports the growth of the hydrogen economy and helps to promote a more sustainable future for the energy sector.

As the hydrogen being produced in this study is electrolytic hydrogen, using 100% renewable energy in the case of B-20 and BEV rate structures, this qualifies for a $3 per kg tax credit for the first 10 years of operations. The annual hydrogen tax credit is calculated based on Equation 16

Equation 16. IRA tax credit

$$IRA\ tax\ credit\ (\$) = \$3(\frac{\$}{kg}) *\ Annual\ hydrogen\ generated\ (kg)$$

3.3.6 Total Annual Expense

In order to determine the total annual expense associated with hydrogen production, the model takes into account all of the expenses incurred during a given year, subtracting any revenue or credits generated as a result of these activities. The model employs a year-zero approach, which represents the initial construction period during which no hydrogen production occurs. During this year, the expenses associated with the construction phase are considered as costs and are presented in Table 12.

Table 12. Year zero expense

Components	Remarks
Electrolyzer Capex	Always
Solar & Battery Capex	Only in solar pathways
Infrastructure Setup Cost	Always

For all the other years the annual expense is calculated using Equation 17. By factoring in all of the relevant expenses and revenue streams over time, the model provides a comprehensive view of the economic viability of hydrogen production and can be used to inform investment decisions.

Equation 17. Annual Expense

$$
\begin{aligned}
&\mathit{Annual\ expense}(\$)\\
&\quad = \mathit{Annual\ energy\ cost}(\$)(\text{Equation } \mathbf{7})\\
&\quad + \mathit{Electrolyzer\ maintence\ cost}(\$)\ (\text{Equation } \mathbf{12})\\
&\quad + \mathit{Labour\ Cost}\ (\$)(\text{Equation } \mathbf{14})\\
&\quad - \mathit{Annual\ LCFS\ reveue}(\$)\ (\text{Equation } \mathbf{15})\\
&\quad - \mathit{IRA\ tax\ credit}\ (\$)(\text{Equation } \mathbf{16})
\end{aligned}
$$

After calculating the annual cash flow for each year from year zero to year fifteen, the next step is to determine the net present value (NPV) of the total cash flow. In this analysis, a discount rate of 5% was applied to the cash flows in order to account for the time value of money and to adjust for inflation over the period of analysis using Equation 18. By discounting the future cash flows back to their present-day value, the NPV provides a more accurate assessment of the economic viability of the hydrogen production project, accounting for the costs and benefits of the investment over time. The NPV is a widely used financial metric that can be used to compare different investment opportunities and inform decision-making in a variety of industries, including the energy sector.

Equation 18. NPV of expense

$$
\begin{aligned}
&\mathit{NPV\ of\ expense}\ (\$)\\
&\quad = \mathit{overallcost\ in\ year}\ 0\ (\$)\\
&\quad + \mathit{NPV}(5\%, \mathit{yearly\ cash\ flow}\ (\mathit{from\ year}\ 1\ \mathit{to\ year}\ 15)(\$))
\end{aligned}
$$

The next step is to discount the hydrogen produced in fifteen years. Discounting physical quantities that will be produced over a few years can help to ensure that the costs and benefits of the project are properly accounted for. For example, if a company plans to invest in a manufacturing facility that will produce a certain amount of product over the next five years, the future value of those products should be discounted to reflect the time value of money. This can help the company make more informed decisions about the investment and avoid potential losses or missed opportunities. The hydrogen produced is also discounted using a 5% discount rate, as shown in Equation 19.

Equation 19. Discounted hydrogen for year zero

$$NPV\ hydrogen\ (kgs) =$$

$$NPV\ (5\%, Annual\ hydrogen\ generated\ (from\ year\ 1\ to\ tear\ 15)(kg))$$

The final step in this analysis is to calculate the LCOH, which is a commonly used metric for assessing the cost-effectiveness of hydrogen production projects. The LCOH is calculated by dividing the total expense, as determined by the NPV of all costs and revenues associated with the project, by the total amount of hydrogen produced over the same period, also in NPV as shown in Equation 20.

Equation 20. LCOH ($/kg)

$$LCOH\ (\frac{\$}{\text{kg}}) = \frac{NPV\ of\ expense\ (\$)\ (\text{Equation } \mathbf{18})}{NPV\ of\ hydrogen\ (\$)(\text{Equation } \mathbf{19})}$$

By factoring in all relevant costs and revenues over the lifetime of the project, the LCOH provides a comprehensive measure of the cost-effectiveness of the hydrogen production process and can be used to compare different production methods and inform investment decisions in the energy sector. Ultimately, the LCOH is a crucial metric for ensuring the economic viability of hydrogen production and promoting sustainable energy practices in the future.

CHAPTER 4. RESULTS

This chapter provides a summary of the results of the study, including an analysis of the cost components associated with the LCOH. The outcomes of the model for both the scenarios are discussed in this section, allowing for a determination of the most cost-effective alternative for generating on-site electrolytic green hydrogen for HTA. The following subsections describe the LCOH that can be achieved using different electricity rate structures.

4.1 Scenario 1: Business as usual (BAU)

In Scenario 1, onsite electrolytic green hydrogen is generated using a NEL MC500 electrolyzer and grid-supplied electricity, with no additional solar PV or battery system to support the hydrogen generation. All the utility rate structures used in Scenario 1 are shown in Table 13.

Table 13. Scenario 1: BAU

Rate Structure	Percentage of renewable energy	Remarks
B-20 (T) + E-GT	100%	With E-GT a customer can procure 100% renewable electricity.
BEV -2 (T) + E-GT	100%	With E-GT a customer can procure 100% renewable electricity.
RTP (NP-15)	33.60%	Same percentage of renewables as the California grid in 2021 (Commission, 2021).

The outcomes obtained from the model evince that the B-20 (T) rate, in combination with the E-GT rate supplement, is the lowest cost choice for producing onsite electrolytic green hydrogen, as compared to the other two utility rate structures. However the difference between the LCOH obtained using B-20 (with E-GT) and RTP is only $0.01 per kg of hydrogen, which is within the noise in the modeling approach (i.e. the two results are essentially identical). The levelized cost of electrolytic hydrogen results are shown in Table 14 below.

Table 14. LCOH for Scenario 1.

Rate structure	Levelized cost of Hydrogen ($/kg)
B-20	$ 6.08
BEV	$ 7.79
RTP	$ 6.09

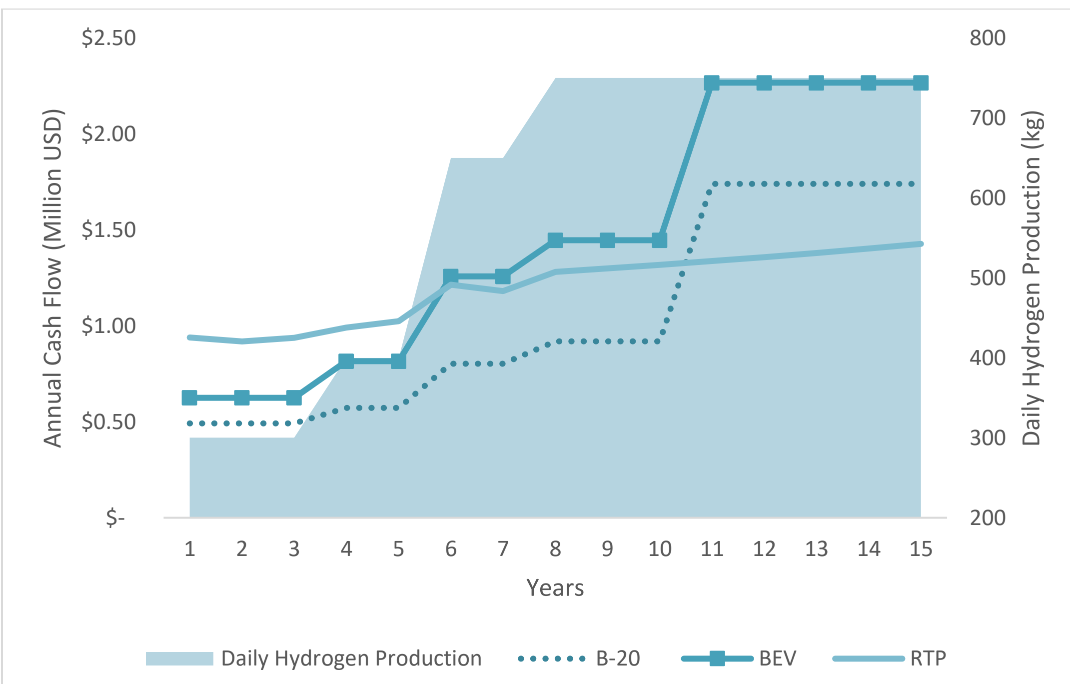

Figure 28. Scenario 1: Annual operating cost

It is noteworthy that, after ten years, when no more IRA credits can be generated, the annual operating expenses of an electrolyzer using a B-20 rate schedule become more expensive than using RTP as shown in Figure 28 above. Therefore, it is recommended that HTA consider shifting from the B-20 rate structure to RTP if possible after ten years. This may reduce the LCOH further. By 2034, it is also anticipated that California's electricity grid will be much cleaner, as the state aims to generate 100% of its electricity from renewable sources by 2045 (CLI, 2018).

A sensitivity analysis was done to examine the cost implications associated with various demand charge levels in the context of the RTP scenario. Since RTP is a speculative future rate, the structure of demand charges and energy charges is unknown and subject to the rate-setting policy process. The analysis demonstrates as expected that the levelized cost of hydrogen (LCOH) is directly affected by the demand charge, with higher demand charges leading to higher LCOH values as shown in Figure 29.

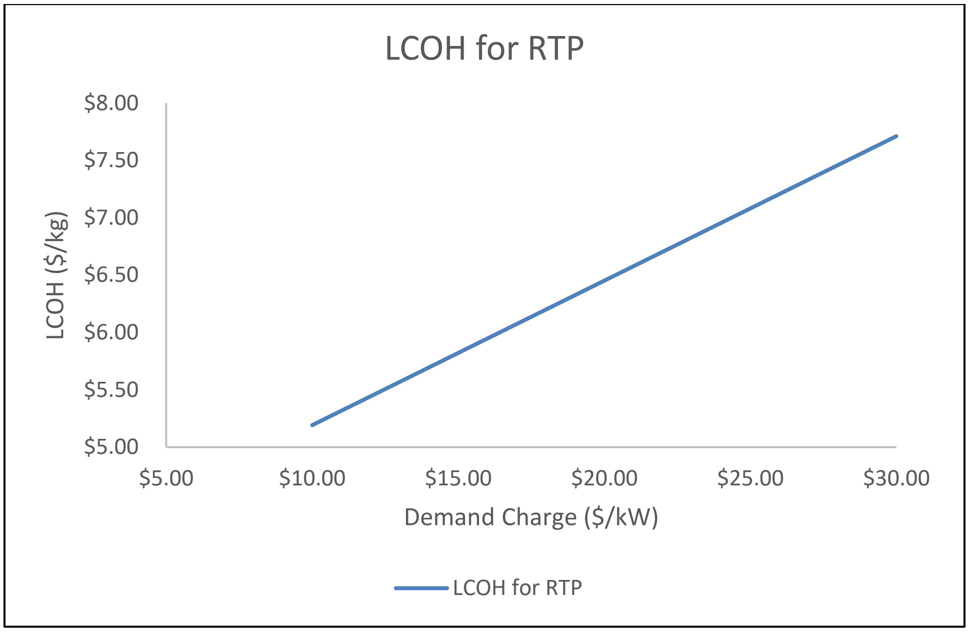

Figure 29. Sensitivity analysis for LCOH for RTP

As part of the analysis of the impact of RTP on LCOH, a retail adder of $0.075 per kWh was employed in the context of a sensitivity analysis. This was a crucial factor, as the retail adder represents the fees charged by the utility provider for the upkeep, maintenance, and operation of the existing utility infrastructure per unit of electricity consumed. The retail adder was calculated as the difference between the annual hourly average energy price of the B-20 rate structure and the hourly average RTP over the next 15 years of the NP-15 hub. With the inclusion of a retail adder of $0.075 per kWh of energy consumed, the LCOH generated using RTP increased from $6.09 per kg of hydrogen to $9.79 per kg of hydrogen.

4.2 Scenario 2: Including onsite Solar PV & Battery

In this scenario, the hydrogen is generated onsite using the same two utility rate structures and E-GT rate supplement, along with a grid-intertied 1000 kW-DC solar PV array and a 500 kW / 1000 kWh battery system. Due to the system being installed behind the meter, the solar PV is limited to 1000 kW in accordance with California's net metering regulations. The first two rate structures stated in Table 13 are used for calculating LCOH in Scenario 2. As stated above, this scenario only has two utility rate schedules i.e., B-20 and BEV.

The analysis shows that, when incorporating onsite solar generation and battery storage, B-20(T) is still the better option for HTA to generate onsite electrolytic hydrogen. However, adding the solar array and battery does not further bring down the levelized cost of hydrogen, as shown in Table 15.

Table 15. LCOH for Scenario 2, which includes 1 MW of solar generation and 500 kW / 1000 kWh of battery storage.

Rate structure	Levelized cost of Hydrogen ($/kg)
B-20 + E-GT	$6.61
BEV + E-GT	$7.84

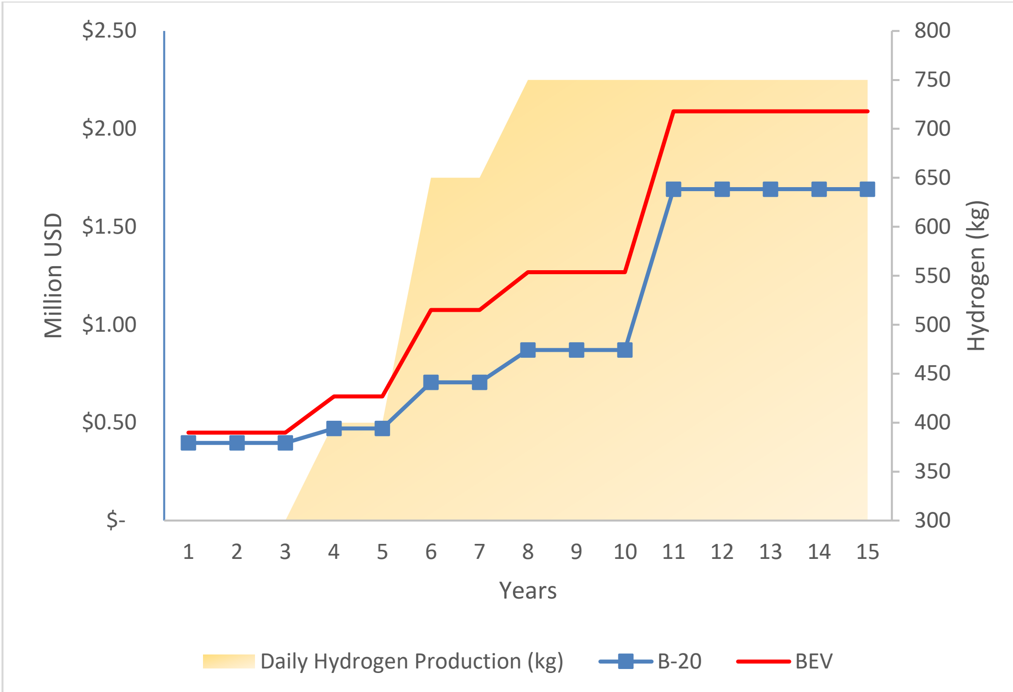

Figure 30. Scenario 2: Annual operating cost

Figure 30 shows the annual operation cost for the generating electrolytic hydrogen. Scenario 2 also follows a similar pattern to Scenario 1, with operational costs increasing as the daily hydrogen demand increases.

<u>4.2.1 Incentives for Solar PV and battery storage.</u>

As indicated by the findings presented in section 4.2, the initial capital investment required for the installation of a solar photovoltaic (PV) and battery storage system raises the LCOH. However, IRA incentives can be used to reduce the upfront cost. Before the enactment of the IRA, entities that installed solar generation facilities could claim an Investment Tax Credit (ITC), provided that they had tax liability that enabled them to claim the credit. The ITC is a federal tax credit designed to encourage the installation of solar energy systems by reducing the federal income tax liability for a percentage of the cost of the solar system installed during the tax year (McGuireWoods, 2023).

The IRA extends the existing energy investment tax credit (ITC) for applicable energy projects. The Clean Electricity ITC maintains a 30% credit for solar PV energy generation projects constructed before the end of 2033. It also creates a 30% credit for energy storage technology and microgrid controllers. This credit will gradually reduce to 22.5% in 2034 and 15% in 2035 as shown in Figure 31 (EERE, 2023).

			Start of Construction						
			2006 to 2019	2020 to 2021	2022	2023 to 2033	The later of 2034 (or two years after applicable year[a])	The later of 2035 (or three years after applicable year[a])	The later of 2036 (or four years after applicable year[a])
ITC	Full rate (if project meets labor requirements[b])	Base Credit	30%	26%	30%	30%	22.5%	15%	0%
		Domestic Content Bonus				10%	7.5%	5%	0%
		Energy Community Bonus				10%	7.5%	5%	0%
	Base rate (if project does not meet labor requirements[b])	Base Credit	30%	26%	6%	6%	4.5%	3%	0%
		Domestic Content Bonus				2%	1.5%	1%	0%
		Energy Community Bonus				2%	1.5%	1%	0%
	Low-income bonus (1.8 GW/yr cap)	<5 MW projects in LMI communities or Indian land				10%	10%	10%	10%
		Qualified low-income residential building project / Qualified low-income economic benefit project				20%	20%	20%	20%

Figure 31: Summary of Investment Tax credit (ITC) values over time.
Source: (EERE, 2023)

Furthermore, the Clean Electricity ITC provides a 10% bonus for meeting domestic manufacturing requirements and a 10% bonus for projects located in low-income communities as defined by the New Markets Tax Credit. As the proposed HTA hydrogen refueling site is located in Eureka, and the system sizing recommended is less than equal to 1MW, HTA can avail the 30% base credit, a10% bonus credit if the components used are manufactured with in the United States, and an additional 10% as the proposed project is less than 5 MW and in a low-income community. Hence a sensitivity analysis was conducted to assess the LCOH if some or all of these tax credits can be availed by HTA. Table 16 shows what the LCOH would be if the solar PV and battery energy storage system used with the conventional utility rate structures was incentivized using the ITC. The ITC of 50% can bring down the LCOH to \$6.17 per kg, which is still higher than the LCOH achieved in Scenario 1.

Table 16: LCOH when the solar PV and battery energy storage system is incentivized.

Incentives (% of solar PV & battery capex)	B-20	BEV
0%	\$ 6.61	\$ 7.84
15%	\$ 6.48	\$ 7.71
22.5%	\$ 6.41	\$ 7.64
30%	\$ 6.34	\$ 7.58
40%	\$ 6.26	\$ 7.49
50%	\$ 6.17	\$ 7.40
75%	\$ 5.95	\$ 7.18
100%	\$ 5.73	\$ 6.96

However, HTA can apply for other state funding and incentive opportunities and grants to further reduce the upfront cost associated with solar PV and battery energy storage systems. Some of such incentive and grants available are:

1. Self-Generation Incentive Program (SGIP): The CPUC's SGIP incentivizes the deployment of distributed energy resources, offering rebates for qualifying systems, including battery storge systems, installed on the customer's side of the

utility meter (CPUC, 2021b). HTA can qualify for both the Equity and Equity Resiliency program under SGIP, which offer rebates covering approximately 85% to 100% of the cost of an average energy storage system (CPUC, 2021a).

2. Low Carbon Transit Operation Program (LCTOP): The LCTOP provides capital and operating assistance to transit agencies prioritizing disadvantaged communities, aiming to improve mobility and reduce greenhouse gas emissions (DoT, 2023). Transit agencies are awarded funds based on a noncompetitive, formula-based list prepared by the State Controller's Office.
3. Clean Mobility Options Voucher Pilot Program (CMOVPP): CMOVPP is a statewide funding program that supports zero-emission car-sharing, ridesharing, bike-sharing, and transit services for low-income and disadvantaged communities. The program provides up to $1 million in voucher funds per project to cover the costs of vehicles, infrastructure, planning, outreach, and operations for up to three years (CMO, 2022).

If HTA can avail such incentives and grants, they can achieve a LCOH of as low as $5.03 per kg of hydrogen, which would offer significant savings compared to commercially procured hydrogen at $7 to $9 per kg, as shown in Figure 32 below.

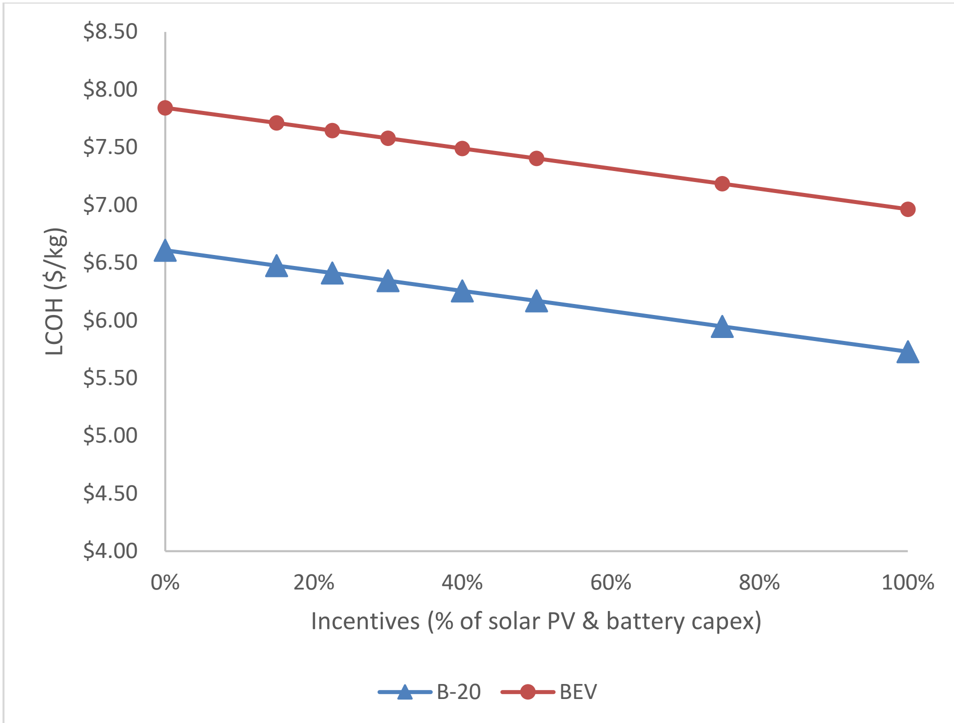

Figure 32: LCOH when the solar PV and battery energy storage system is incentivized.

4.3 Electrolyzer utilization rate

The findings of the aforementioned analysis indicate that the lowest LCOH is achieved when HTA utilizes a NEL MC500 electrolyzer and the B-20 + E-GT utility rate schedule, without incorporating solar PV and battery technologies. However, the model was also employed to assess the optimal oversizing of the electrolyzer, which can lead to a reduction in LCOH by avoiding peak hours. To conduct this analysis, the same model was utilized, and the aforementioned steps were repeated for both the MC250 and MC500 electrolyzers for daily hydrogen production ranging from 100 kg to 1050 kg over a 15-year period using B-20 + E-GT rate schedules. The key difference in this analysis was that the LCOH for 22 distinct daily hydrogen production targets were simulated for the MC500 electrolyzer, while only 9 distinct daily hydrogen production targets ranging from 100 kg to 500 kg per day were simulated for the MC250 electrolyzer.

Based on the results presented in Figure 33, the most cost-effective method for producing hydrogen through electrolysis is to utilize the electrolyzer at a rate of 75%. In other words, optimizing the utilization rate of the electrolyzers to 75% provides the best economical solution for avoiding peak demand hours and reducing annual utility costs. However, if the utilization rate exceeds 75%, it may be beneficial to consider acquiring an additional electrolyzer instead of running the same at a higher utilization rate.

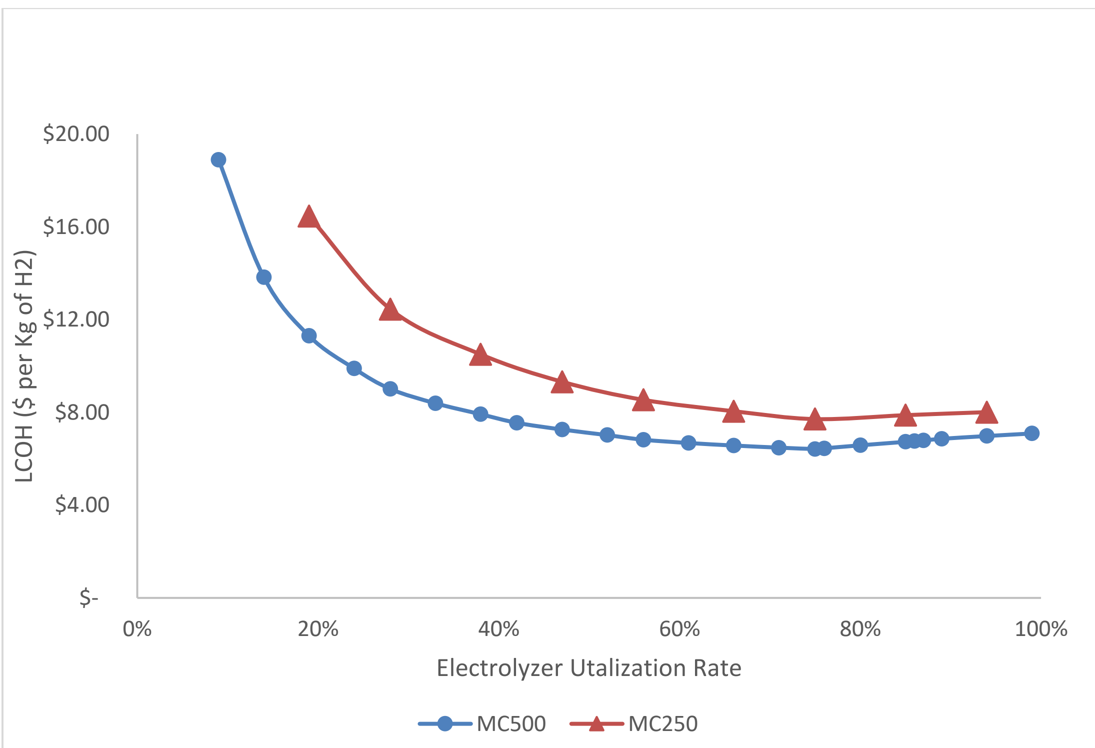

Figure 33: Electrolyzer utilization rate vs the LCOH

Additionally, the demand charge per kg of hydrogen generated follows a similar pattern as the LCOH when compared to the electrolyzer utilization rate. Figure 34 shows that the demand charge continues to reduce as the utilization rate increases. However, as soon as the electrolyzer utilization is greater than 75%, the demand charges per kg of hydrogen increase. This is because hydrogen has to be generated during peak hours which have higher demand charges. On the other hand, the energy charges consistently rise as the electrolyzer utilization rate increases. This is because more energy is required to generate more hydrogen.

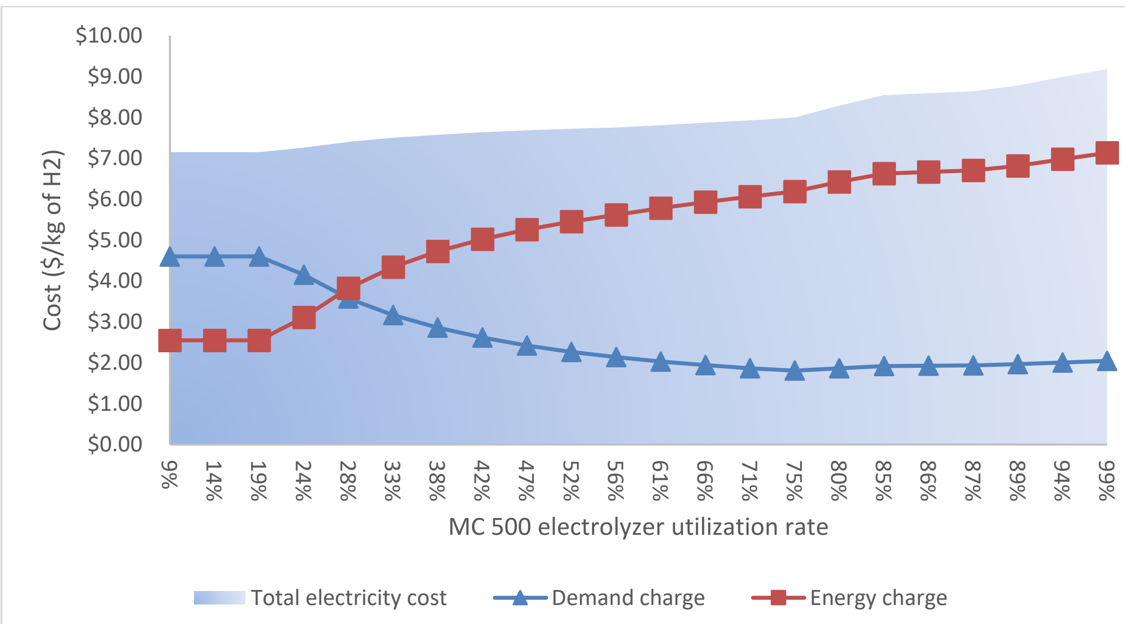

Figure 34: Annual utility cost vs electrolyzer utilization rate

4.4 Sensitivity Analysis and Uncertainty

As previously mentioned, the value of LCFS credits is subject to fluctuation over time. Thus, a sensitivity analysis was carried out to investigate the potential impact of varying LCFS credit prices on the LCOH. This sensitivity analysis evaluated the influence of LCFS credits ranging from \$63 to \$200 per metric ton of CO_2e on the LCOH, as shown in Figure 35 below. The findings of the sensitivity analysis indicate that as the value of LCFS credits increases, the LCOH decreases significantly. However, in the case of the RTP, the LCOH remains relatively unchanged as the Carbon Intensity (CI) score for California's grid is currently high. Nevertheless, as more renewable electricity generation sources are integrated into the grid, the CI score for RTP will decrease, resulting in a reduction in the LCOH for RTP.

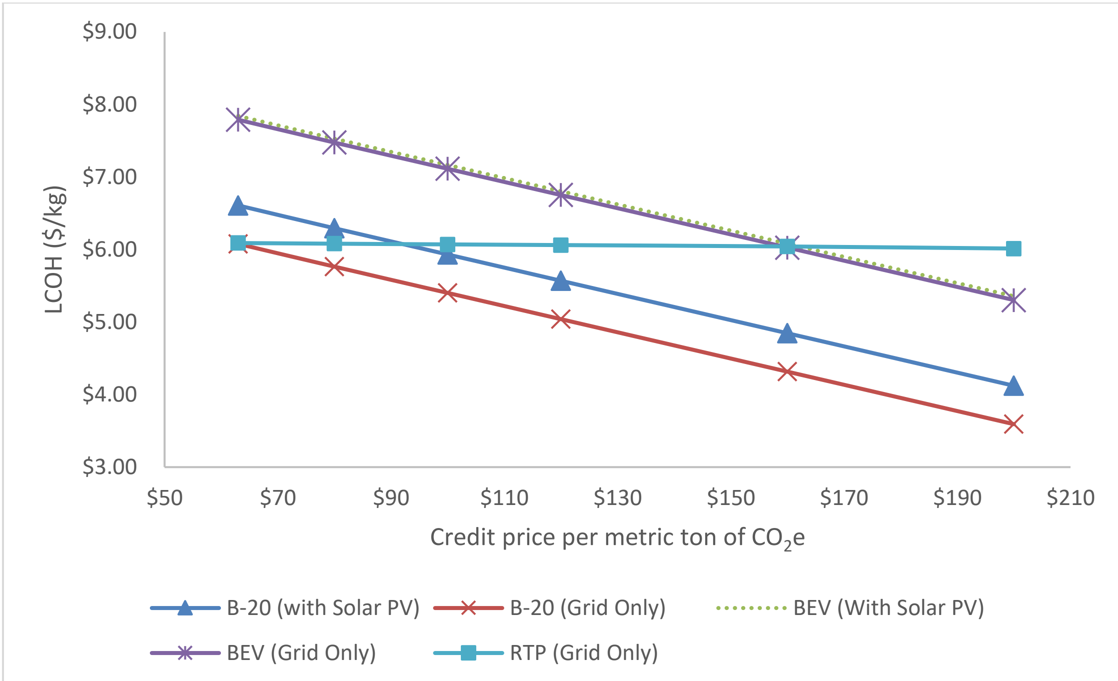

Figure 35: Sensitivity analysis for LCFS credit value Vs LCOH

As discussed in section 3.3.4, The LCFS credit generated through RTP is currently low, with only about $0.04 per kg of hydrogen, due to the carbon intensity (CI) value of California's grid standing at 164.46 gCO_2/MJ. However, as California's grid increases the fraction of energy generated from renewable energy sources, its CI value is expected to decrease, resulting in higher LCFS credits generated in the future. Therefore, to assess the impact of a cleaner grid, a projected CI value for 2031 was used as an average CI for the 15-year life of the electrolyzer, assuming that the electrolyzer installed in a project that begins construction in 2024 would reach its mid-life in 2031.

As per the California Transportation Supply (CATS) model, the average estimated CI value of California's grid in year 2031 is expected to be 71.3 gCO_2/MJ (CARB, 2023c). Using the LCFS credit calculator and a CI value of 71.3 gCO_2/MJ and keeping all the previous assumptions stated in section 3.3.4, HTA would generate $0.74 LCFS credits per kg of hydrogen. This would bring down the LCOH for the RTP case to $5.42 per kg of hydrogen. If the value of the credit per metric ton of CO_2e increases from the present value of $63 to $200, the LCOH significantly decreases to $3.89 per kg of hydrogen for the RTP case (as shown in Figure 36) without the assumed retail adder of $0.075 per unit of energy consumed (kWh).

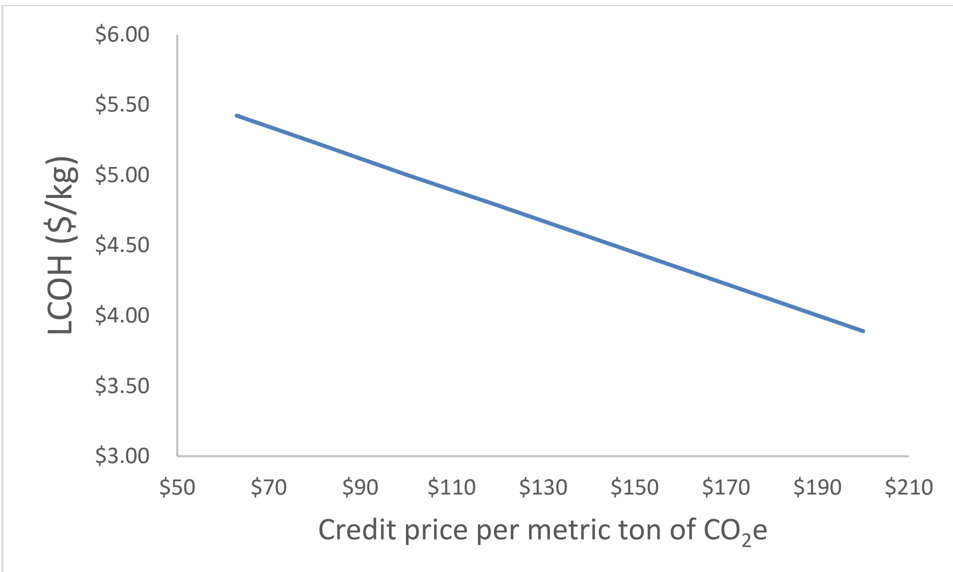

Figure 36: LCOH vs. LCFS credit value analysis for RTP when considering CI of California grid for 2031.

Another important factor to consider while interpreting the results is that the LCOH is heavily dependent on the discount factor used for the study. The discount rate is an economic concept used to calculate the present value of a future stream of income or costs. It is the rate at which future income or costs are discounted to their present value. The discount rate reflects the time value of money, which means that money available today is worth more than the same amount of money in the future due to the opportunity cost of not having it available for investment or consumption. The choice of discount rate can have significant implications for economic decision-making, particularly in long-term investments, as a higher discount rate results in a lower present value and vice versa. Different discount rates may be used for different types of projects, depending on factors such as risk, time horizon, and social preferences. Therefore, the choice of discount rate is an important consideration in economic analysis and policymaking. California regulatory agencies, such as CARB use a variety of discount rates depending on the specific analysis and purpose. For example, CARB's Scoping Plan, which outlines the state's strategy for reducing GHG emissions, uses a range of discount rates from 1.5% to 3%, while its analysis of the costs and benefits of the Cap-and-Trade program uses a discount rate of 3% (CARB, 2017) (CARB, 2018a).

Although a 5% discount rate was used in this study, a sensitivity analysis was conducted to evaluate the impact of discount rates on the levelized cost of hydrogen (LCOH). Figure 37 below, shows the results of this analysis, which varied the discount rate from 3% to 7%. The analysis demonstrates that at lower discount rates, the on-site electrolytic hydrogen is more cost-effective than at higher discount rates. However, regardless of the discount rate, Scenario 1 with the B-20 utility rate structure consistently emerges as the most economically viable option for HTA. By considering a range of potential discount rates, this analysis provides greater insight into the long-term financial viability of on-site hydrogen generation for HTA and highlights the importance of carefully evaluating the costs and benefits of different scenarios in order to make informed decisions about energy infrastructure investments.

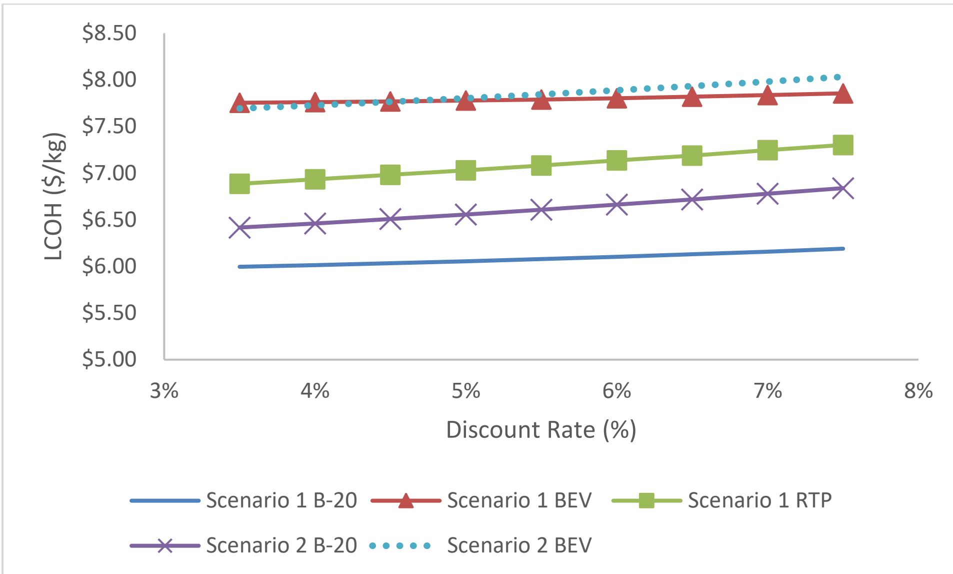

Figure 37. Discount rate sensitivity analysis for LCOH of green hydrogen. Compared to this, HTA will be procuring hydrogen from Air Products between $7 to $9 per kgs.

CHAPTER 5. DISCUSSION & RECOMMENDATIONS

From Section 4.1 and 4.2 it is clear that generating onsite hydrogen with utility rate schedule B-20 (T) in combination with E-GT rate supplement is the most cost effective method for HTA presently. Additionally, using solar PV and battery system does reduce the operating cost, but the level of these savings offered by a 1000 kW-DC solar PV, 500 kW-1000 kWh battery system is not balanced by a high upfront capital cost, resulting in an overall increase of the LCOH of this system. In other words, the reduction in the operating costs is not sufficient to the cost savings offered are shown in Table 17 below.

Table 17. Utility cost savings with solar PV & battery system

Daily Hydrogen Production (kg)	Electrolyzer Utilization rate	Utility Cost Savings with Solar	
		B-20	BEV
300	28%	14%	21%
400	38%	12%	16%
650	61%	7%	9%
750	71%	3%	8%

It is clear from the analysis that the savings offered by the solar PV and battery system decrease as the electrolyzer utilization rate increases. This is due to the fact that as the demand for hydrogen increases, more hydrogen needs to be produced during non-solar hours, resulting in decreased energy savings. Additionally, solar PV and battery systems can offer utility cost savings when used in conjunction with the grid, but given the assumptions considered for this study, the initial high capital cost of installing such a system cannot be offset over the 15-year lifespan of the electrolyzer.

Based on the assumptions and parameters of this study, generating onsite green electrolytic hydrogen is a more cost effective pathway for HTA than ongoing procurement of SMR hydrogen from off-site. As with the recommended system sizing stated in Table 18 below, the LCOH is $6.08 and as per information provided by HTA, they are currently procuring liquid hydrogen from a commercial supplier at $7 to $9 per kg.

Table 18. Recommended system sizing.

System Sizing	Recommendation
Electrolyzer	MC500
Utility Rate Schedule	B-20 (T) + E-GT
LCOH ($/Kg)	$ 6.08

Based on an average cost of $8 per kg for hydrogen purchased from a commercial supplier, Air Products, HTA could potentially save approximately $6 million over the 15 year period (as shown in Figure 38 below) by generating hydrogen on-site at a cost of $6.08 per kg, as estimated in this study. This cost savings, combined with the fact that the on-site hydrogen is "green" and therefore emits significantly less greenhouse gas (GHG) emissions than the "grey" hydrogen supplied by Air Products, represents a compelling economic and environmental case for HTA to pursue on-site hydrogen generation. By reducing their reliance on fossil fuels and embracing clean energy sources, HTA can not only save money, but also contribute to a more sustainable and environmentally responsible energy landscape.

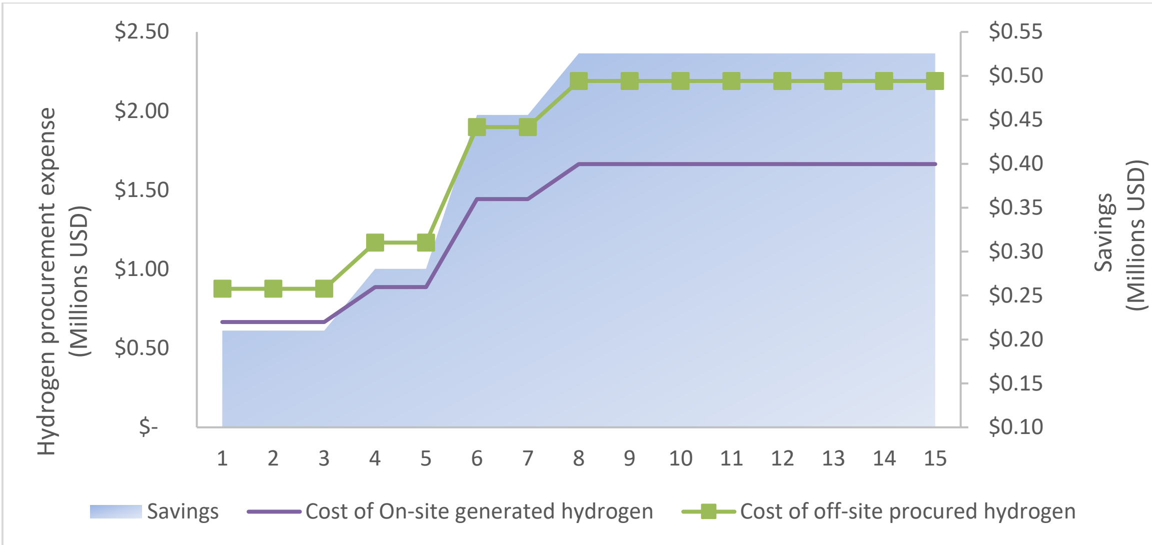

Figure 38. Cost savings

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APPENDICES

Appendix A: Electric Rate Structure

This thesis aims to determine the levelized cost of hydrogen (LCOH) for on-site electrolytic hydrogen generation in the Eureka, California region. To perform the analysis, the study considers the utility rate structures offered by Pacific Gas and Electric (PG&E), the primary electricity provider in the area. In addition, the thesis incorporates the real-time pricing data from CAISO's NP-15 hubs to calculate the LCOH. Specifically, the study uses three PG&E rate structures to perform the analysis, with the ultimate goal of estimating the cost of producing hydrogen through electrolysis. The three utility rate structures used in this analysis are:

<u>Electric Green Tariff (E-GT):</u> PG&E's Electric Green Tariff (E-GT) is a program that allows customers to choose to purchase 100% renewable energy for their home or business. Under this program, customers pay a premium for the renewable energy they consume, which is added to their monthly energy bill. To enroll in E-GT, customers must have an active PG&E electric account, meet the program's minimum participation requirements, and agree to a minimum 12-month contract period. Additionally, customers must ensure that they have a compatible electric meter installed at their location. Customers who enroll in E-GT will continue to receive their electricity from PG&E's distribution system, but the electricity they consume will be sourced entirely from renewable energy facilities. The premium customers pay for E-GT is used to support the development and maintenance of renewable energy projects, such as solar, wind, and

geothermal facilities. By enrolling in E-GT, customers can reduce their carbon footprint, support the development of renewable energy, and demonstrate their commitment to sustainability (Kenney, 2020). In this study the E-GT tariff has been used along with the PG&E's conventional B-20 & BEV rate schedules with the aim of generating maximum LCFS & IRA credits. The premium paid on the B-20 & BEV to use 100% renewable energy is shown in *Figure A **1***.

Customer Class	Solar Charge	Generation Credit	Program Charge**	PCIA	Total
Schedule E-20 T / B-20 T					
-- 2015 Vintage	$0.09034 (I)	($0.12849) (R)	$0.05608 (I)	$0.00053 (R)	$0.01846 (I)
-- 2016 Vintage	$0.09034 (I)	($0.12849) (R)	$0.05608 (I)	$0.00050 (R)	$0.01843 (I)
-- 2017 Vintage	$0.09034 (I)	($0.12849) (R)	$0.05608 (I)	$0.00026 (R)	$0.01819 (I)
-- 2018 Vintage	$0.09034 (I)	($0.12849) (R)	$0.05608 (I)	$0.00021 (R)	$0.01814 (I)
-- 2019 Vintage	$0.09034 (I)	($0.12849) (R)	$0.05608 (I)	$0.00005 (R)	$0.01798 (I)
-- 2020 Vintage	$0.09034 (I)	($0.12849) (R)	$0.05608 (I)	($0.00135) (R)	$0.01658 (I)
-- 2021 Vintage	$0.09034 (I)	($0.12849) (R)	$0.05608 (I)	($0.00322) (R)	$0.01471 (R)
-- 2022 Vintage	$0.09034 (I)	($0.12849) (R)	$0.05608 (I)	$0.01065 (R)	$0.02858 (I)
-- 2023 Vintage	$0.09034 (N)	($0.12849) (N)	$0.05608 (N)	$0.01065 (N)	$0.02858 (N)
Schedule BEV-2					
-- 2019 Vintage	$0.09034 (I)	($0.14774) (R)	$0.06135 (R)	$0.00005 (R)	$0.00400 (R)
-- 2020 Vintage	$0.09034 (I)	($0.14774) (R)	$0.06135 (R)	($0.00157) (R)	$0.00238 (R)
-- 2021 Vintage	$0.09034 (I)	($0.14774) (R)	$0.06135 (R)	($0.00375) (R)	$0.00020 (R)
-- 2022 Vintage	$0.09034 (I)	($0.14774) (R)	$0.06135 (R)	$0.01239 (R)	$0.01634 (I)
-- 2023 Vintage	$0.09034 (N)	($0.14774) (N)	$0.06135 (N)	$0.01239 (N)	$0.01634 (N)

Figure A 1: E-Gt rate supplement. Source: (Kenney, 2020)

<u>B-20 (T):</u> To be considered eligible for service under Schedule B-20, a customer must have a maximum demand that has surpassed 999 kilowatts for at least three consecutive months within the past 12-month period (Kenney, 2021). As HTA maximum demand would exceed the 999 kW limit in all the cases, HTA is eligible to avail this rate schedule. This rate schedule is used along with E-GT to generate onsite hydrogen. The energy and demand charges for B-20 rate schedule along with ToU periods are shown in Figure A 2.

	Secondary Voltage	Primary Voltage	Transmission Voltage
Total Customer Charge Rates			
Customer Charge Mandatory B-20 ($ per meter per day)	$56.65864 (R)	$57.92346 (R)	$157.68814 (R)
Total Demand Rates ($ per kW)			
Maximum Peak Demand Summer	$32.34 (I)	$34.89 (I)	$23.52 (I)
Maximum Part-Peak Demand Summer	$6.41 (I)	$6.59 (I)	$5.61 (I)
Maximum Demand Summer	$29.15 (I)	$26.56 (I)	$17.28 (I)
Maximum Peak Demand Winter	$2.57 (I)	$2.59 (I)	$3.14 (I)
Maximum Demand Winter	$29.15 (I)	$26.56 (I)	$17.28 (I)
Total Energy Rates ($ per kWh)			
Peak Summer	$0.20305 (I)	$0.19869 (I)	$0.17303 (I)
Part-Peak Summer	$0.16468 (I)	$0.15743 (I)	$0.14710 (I)
Off-Peak Summer	$0.13438 (I)	$0.12866 (I)	$0.11817 (I)
Peak Winter	$0.18019 (I)	$0.17243 (I)	$0.16607 (I)
Off-Peak Winter	$0.13414 (I)	$0.12873 (I)	$0.11374 (I)
Super Off-Peak Winter	$0.07245 (R)	$0.06674 (R)	$0.06148 (R)
Power Factor Adjustment Rate ($/kWh/%)	$0.00005	$0.00005	$0.00005

DEFINITION OF TIME PERIODS: Times of the year and times of the day are defined as follows:

SUMMER - Service from June 1 through September 30:

Peak:	4:00 p.m. to 9:00 p.m.	Every day, including weekends and holidays
Partial-peak:	2:00 p.m. to 4:00 pm AND 9:00 p.m. to 11:00 p.m.	Every day, including weekends and holidays
Off-peak:	All other Hours.	

WINTER - Service from October 1 through May 31:

Peak:	4:00 p.m. to 9:00 p.m.	Every day, including weekends and holidays
Super Off-Peak	9:00 a.m. to 2:00 p.m.	Every day in March, April and May, including weekends and holidays
Off-peak:	All other Hours.	

Figure A 2: B-20 rate schedule. Source: (Kenney, 2021)

Business Electric Vehicles (BEV-2): BEV is a schedule that can be selected for commercial EV charging purposes where the usage of non-EV commercial and EV charging is metered separately. There are two distinct rate options available under BEV:

BEV-1 and BEV-2. Customers with kW usage at or below 100 kW are eligible for the BEV-1 rate option, while those with kW usage at or above 100 kW can opt for the BEV-2 rate option (Allen, 2020). This study aims to analyze the LCOH using the BEV-2 utility rate schedule. Compared to the B-20 schedule, BEV-2 has lower demand charges but higher energy charges. This makes it an interesting alternative for comparison. Through this comparison, we aim to gain a better understanding of the impact of demand and energy charges on the LCOH. Cost and ToU information regarding BEV-2 can be found in Figure A 3.

	BEV-1		BEV-2-S (Secondary)		BEV-2-P (Primary / Transmission)	
Total Energy Rates ($ per kWh)						
Peak	$0.38204	(I)	$0.39601	(I)	$0.38713	(I)
Off-Peak	$0.19003	(I)	$0.18278	(I)	$0.17825	(I)
Super Off-Peak	$0.16337	(I)	$0.15951	(I)	$0.15559	(I)
Block Size (kW)	10		50		50	
Subscription Charge (per block)	$12.41		$95.56		$85.98	
Subscription Charge ($ per kW)*	$1.24		$1.91		$1.72	
Overage Fee ($ per kW)	$2.48		$3.82		$3.44	

1. TIME PERIODS: Times of the year and times of the day are defined as follows:

TOU Period	Times	Days
Peak	4:00 p.m. to 9:00 p.m.	Every day including weekends and holidays, all year
Off-Peak	9:00 p.m. to 9:00 a.m. and 2:00 p.m. to 4:00 p.m.	Every day including weekends and holidays, all year.
Super Off-Peak	9:00 a.m. to 2:00 p.m.	Every day including weekends and holidays, all year/

2. SEASONAL CHANGES: Schedule BEV has no seasonal variation.

3. BILLING: A customer's bill is calculated based on the option applicable to the customer as follows.

Figure A 3. BEV-2 utility rate schedule

Real Time Pricing (RTP): Real-time pricing (RTP) is the prices charged to customers that closely match either the underlying wholesale electricity market or the utility's cost of production (EERE, n.d.-b). The real time pricing changes every hour and the future projection for RTP have been obtained from California Public Utilities Commission's (CPUC) "Avoided Cost Calculator" model (CPUC, 2022). Real-time pricing (RTP) is an energy pricing technique in which the price of power adjusts according to the grid's actual demand and supply situations. Real-time pricing also encourages energy suppliers to create more power during peak demand periods, which can assist to eliminate the need for costly and polluting peaker plants. Electricity costs are normally greatest during the afternoon and early evening hours, when energy consumption is at its peak, under California's real-time pricing system. Rates might be two to three times higher during these peak hours than during off-peak hours. Hourly RTP projections for the NP-15 CAISO node were collected from the avoided cost calculator (ACC) model for the next 15 years (CPUC, 2022). The model provided hourly pricing for each year (from 2024 to 2039).

Appendix B: Electrolyzer & Hydrogen Generation Profile

Electrolyzer: As stated in section 2.7.2, there are three major types of electrolyzers available, Alkaline, PEM and SOEC. For this thesis a PEM electrolyzer has been chosen as they offer several advantages over other types of electrolyzers. One of the main advantages is their high efficiency, which is due to their ability to operate at lower temperatures and pressures compared to other types of electrolyzers. This allows them to consume less energy, resulting in lower operational costs. Additionally, PEM electrolyzers have a fast response time and can quickly ramp up or down their production of hydrogen, making them ideal for applications that require dynamic operation. Furthermore, they are compact and lightweight, making them suitable for mobile or decentralized applications. Finally, PEM electrolyzers do not require the use of alkaline or corrosive electrolytes, which simplifies the design and operation of the system, and makes it easier to integrate with renewable energy sources.

NEL Hydrogen is a leading manufacturer of hydrogen electrolyzers, and two of their most popular models are the MC250 and MC500 electrolyzers. Both of these models are based on Proton Exchange Membrane (PEM) technology and are designed for industrial-scale hydrogen production. The MC250 model has a production capacity of 250 Nm3/h, while the MC500 has a capacity of 500 Nm3/h. These electrolyzers have a compact and modular design, which allows for easy integration into existing infrastructure and provides flexibility for scaling up production capacity as needed. Additionally, they feature high energy efficiency, fast response times, and low maintenance requirements, making them a cost-effective and reliable solution for large-scale hydrogen production. The MC250 and MC500 electrolyzers are also designed to operate with renewable energy sources, such as wind and solar power, further increasing their sustainability and reducing their carbon footprint. Overall, the MC250 and MC500 electrolyzers from NEL Hydrogen are advanced and reliable systems that offer efficient and sustainable hydrogen production at an industrial scale. Specifications of MC500 and MC250 electrolyzer are shown in Figure B 1 below.

MODEL	MC250	MC500
Class	1.25 MW	2.5 MW
HYDROGEN PRODUCTION		
Net production rate Nm³/h @ 0° C, 1 bar SCF/h @ 70° F, 1 atm kg/24 h	246 Nm³/h 9,352 SCF/h 531 kg/24 h	492 Nm³/h 18,704 SCF/h 1,062 kg/24 h
Delivery pressure – nominal	30 barg (435 psig); full differential pressure H_2 over O_2	
Average power consumption at stack per volume of H_2 gas produced[1]	4.5 kWh/Nm³	
Average power consumption at stack per mass of H_2 gas produced[1]	50.4 kWh/kg	
Purity (concentration of impurities)	99.95% [H_2O < 500 ppm, N_2 < 2 ppm, O_2 < 1 ppm, all others undetectable]	
Purity (concentration of impurities with optional high purity dryer)	ISO 14687:2019(E) Type I, Type II Grade D and SAE J-2719 Type I Grade L 99.9995% [H_2O < 5 ppm, N_2 < 2 ppm, O_2 < 1 ppm, all others undetectable]	
Start-up time (from off state)	< 5 min	
Ramp-up time (minimum to full load)	< 15 sec	
Ramp rate (% of full-scale)	≥ 15% per sec (power input mode)	
Production capacity dynamic range	10 to 100%	
ELECTRICAL SPECIFICATIONS		
Electrical requirements	Typical installation: 6.6 to35 kV, three phase 50 Hz/60 Hz Low voltage, three phase required for balance of plant and ancillary equipment	
Power quality	Total harmonic distortion: < 5%, power factor: > 0.9 nominal power, at normal power	
PHYSICAL CHARACTERISTICS		
Electrolyser container[2] W x D x H	12.2 m x 2.5 m x 3 m (40 ft x 8 ft x 9.9 ft)	12.2 m x 2.5 m x 3 m (40 ft x 8 ft x 9.9 ft)
Rectifier/transformer container[2] W x D x H	6.1 m x 2.5 m x 2.6 m (20 ft x 8 ftx 8.5 ft)	12.2 m x 2.5 m x 3 m (40 ft x 8 ft x 9.9 ft)

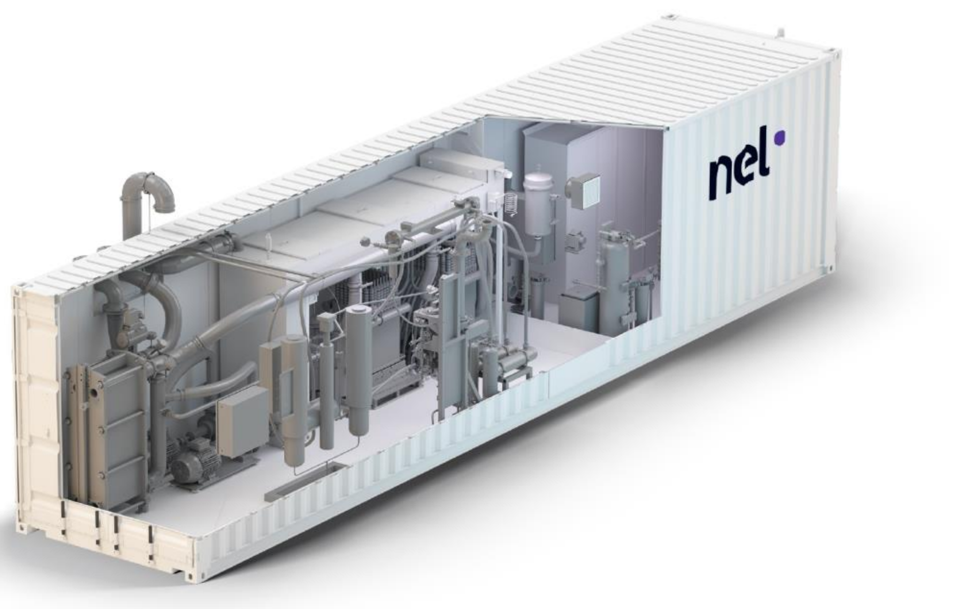

Figure B 1. NEL electrolyzer specification. Source: (NEL, 2020)

Hourly Hydrogen Generation Profile: As stated in Section 3.2.4, different hourly generation profiles were created for the three utility rate structures.

B-20(T) + E-GT: The winter and summer months have different ToU periods for B-20 rate structure. Hence two different hydrogen generation profiles had to be created for the model. The winter and summer hydrogen generation profiles for B-20 rate structure are shown in Figure B 2 and Figure B 3 below respectively.

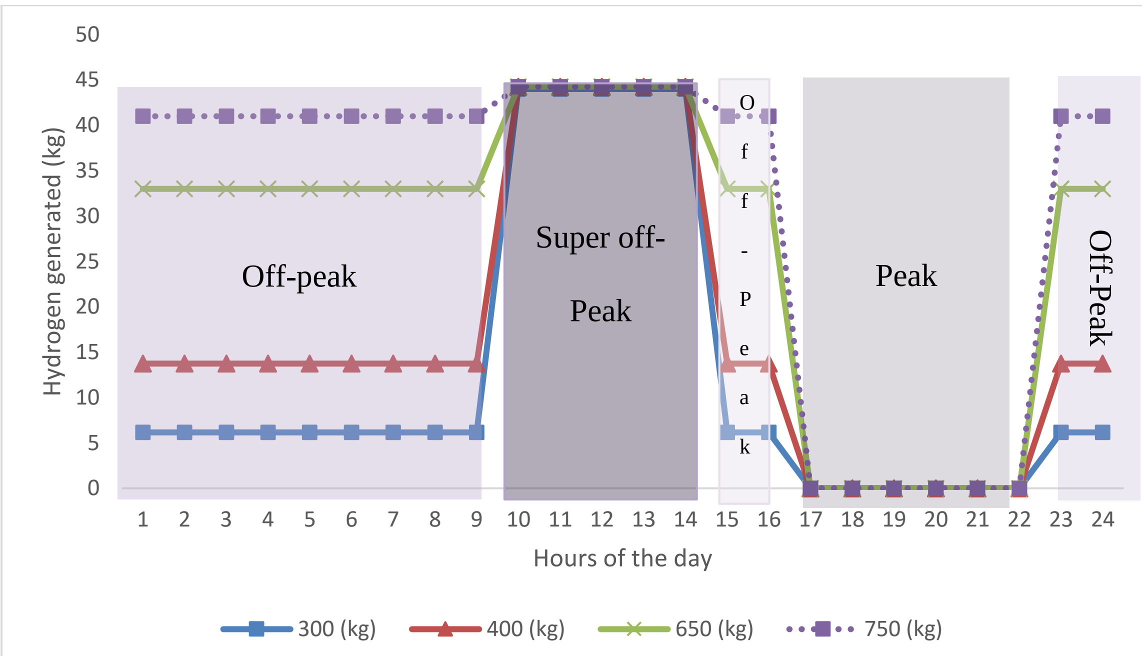

Figure B 2: B-20 winter hourly hydrogen generation profile.

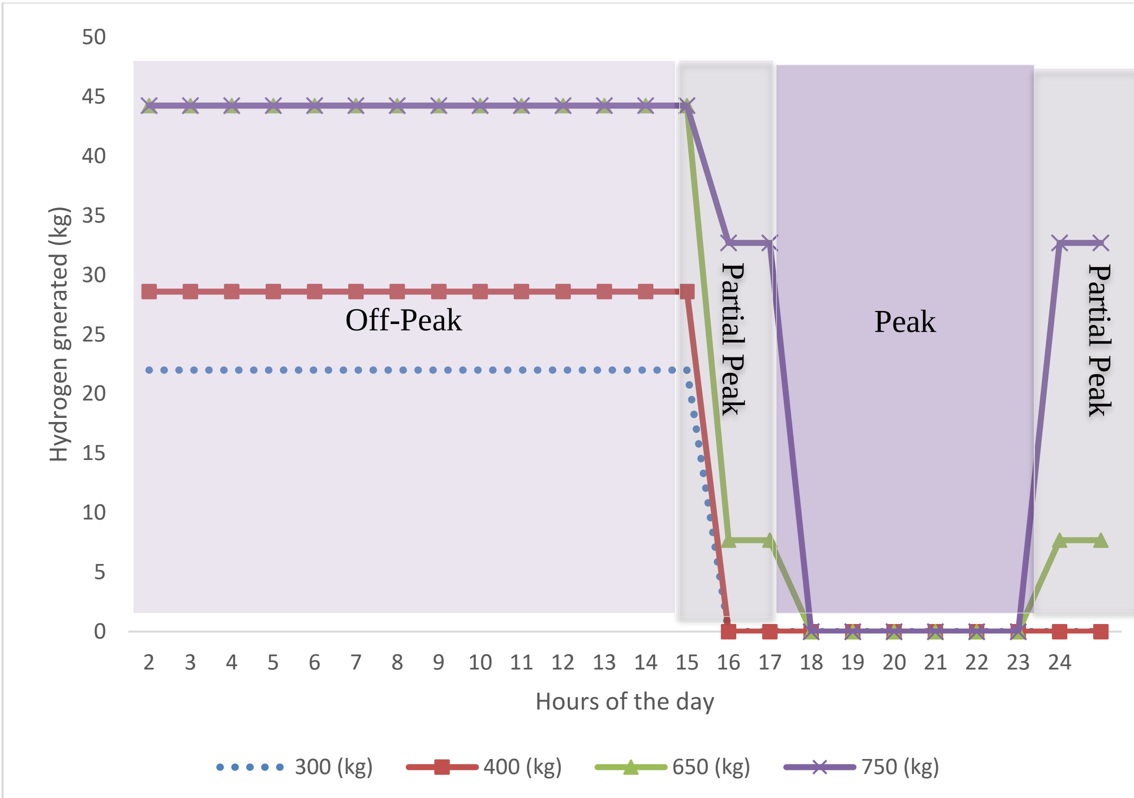

Figure B 3: B-20 Summer hourly hydrogen generation profile.

<u>BEV-2(T) + E-GT:</u> Unlike B-20, BEV-2 has no seasons and only one set of ToU throughout the year. The hourly hydrogen generation profile for BEV-2 is shown in Figure B 4.

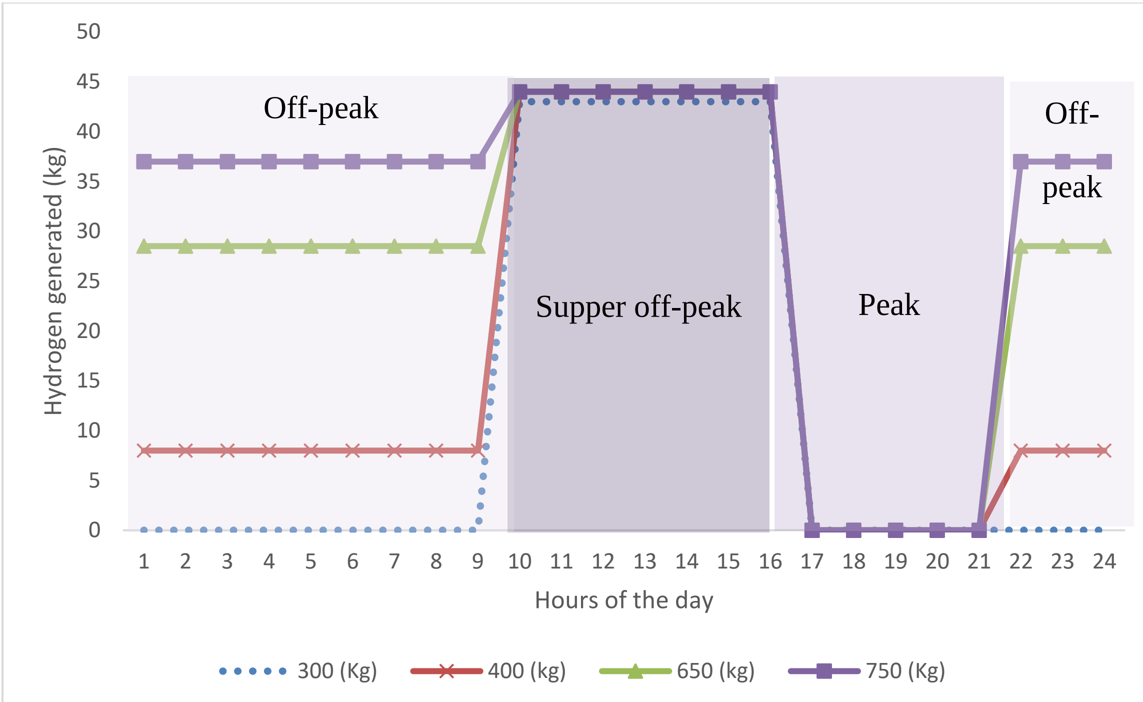

Figure B 4: BEV-2 hydrogen generation profile

<u>RTP:</u> For RTP the hydrogen generation strategy was to produce the maximum amount of hydrogen in hours with the lowest pricing and produce the remaining hydrogen during hours with increasing cost. The hourly hydrogen generation profile for each year is shown in Figure B 5.

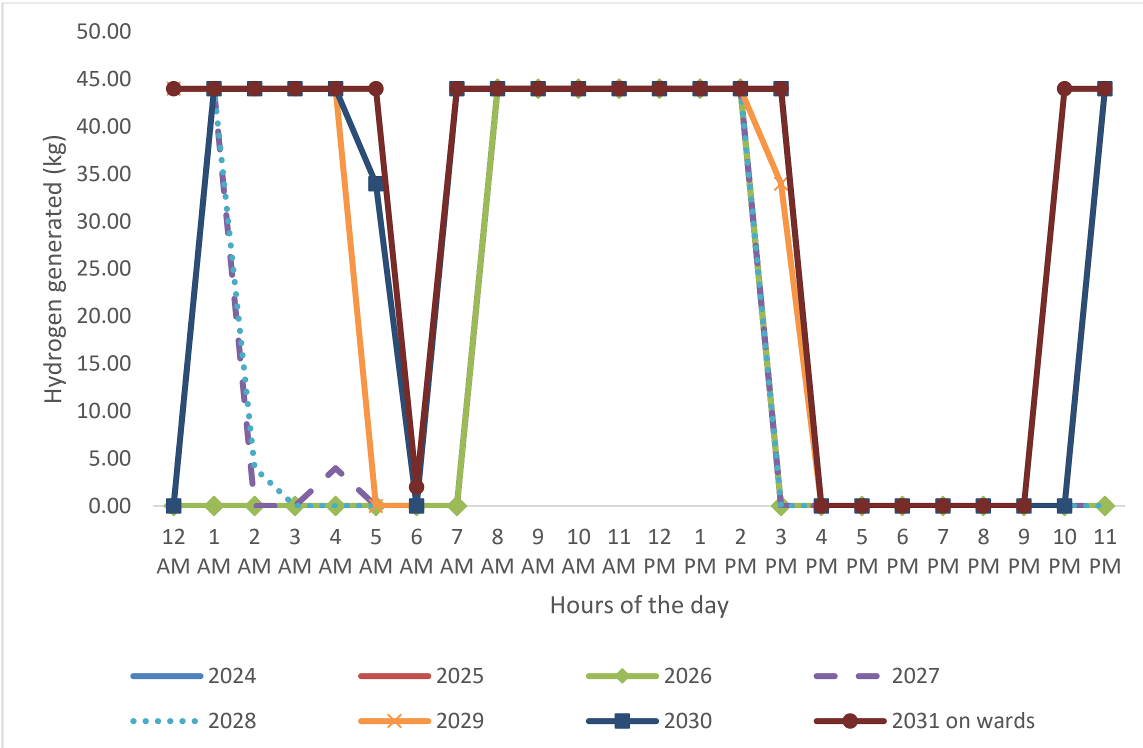

Figure B 5: RTP hourly hydrogen generation profile