ZEN and the art of CLEAN ENERGY SOLUTIONS

Valley Link Hydrogen Production and Energy Farm Feasibility Study

Prepared For:
Tri-Valley San Joaquin Valley Regional Rail Authority

September 2022

VERONICA VARGAS

The Tri-Valley – San Joaquin Valley Regional Rail Authority is leading the implementation of the Valley Link rail project as a model of sustainability – one that could operate on its own created renewable energy, support transit-oriented land use development around station areas, and promote innovation in station access, while maximizing air quality, equity, health, and workforce benefits. This includes ensuring equity to disadvantaged and low-income communities in the design, construction, and operation of the new rail system.

The Valley Link rail project is a mega solution to the jobs and housing challenges faced by the Northern California megaregion, with an emphasis on access to opportunity for equity focus communities. The Northern California megaregion is challenged by one of the most significant jobs-housing imbalances in the state with only one home being built in the Bay Area for every six jobs generated and housing costs in the Bay Area being three times those in the San Joaquin Valley. This challenge has resulted in some of the longest commute times, highest congestion, and worst air quality in the country. Today there is no clean, reliable, high frequency transit alternative to vehicular congestion on Interstates 205 and 580 for more than 105,000 Bay Area workers now commuting daily from their homes in communities in the Northern San Joaquin Valley. These are some of the state's most disadvantaged communities with the highest poverty rates located in one of the most polluted air basins in the United States.

With transportation being responsible for 41% of California's current greenhouse gas emissions the Authority is committed to the use of zero emission vehicles in our efforts to address climate change. While significant emphasis has been placed on battery electric vehicle technology and related charging infrastructure across the state, the Northern California megaregion's clean transportation future needs to consider hydrogen fuel cell vehicle technology where it makes sense. Where hydrogen makes sense is long-distance transit - both bus and passenger rail. Just like electric batteries, hydrogen provides energy storage, but with optimal fueling time and energy capacity for long-distance travel.

To date, the state has already invested in a number of these hydrogen vehicle technologies and several transit agencies across the state are already producing their own hydrogen fuel. The sustainability vision of the Valley Link rail project seeks to explore significantly expanding on this model, connecting the Northern California megaregion with the first passenger rail system in California running on self-produced, green hydrogen and a hydrogen fuel production facility able to support the clean energy goals other transit and heavy truck operators. This vision is also one of self-reliance whereby the cost of operating the new rail system could be offset by the production of hydrogen and sale of excess production to other users. This model of sustainability and self-sufficiency is important as it inherently connects the hydrogen fuel producer and user with the goal of reducing the cost of the overall transit operations for the public and offsetting state and federal transit subsidies. Public investments in developing hydrogen production can also serve as a catalyst for private investment, accelerating progress towards meeting climate goals and promoting the economy.

To achieve this vision the Authority has prepared the Valley Link Hydrogen Production and Energy Farm Feasibility Study. The goal of this study was to specifically assess the physical and financial feasibility of developing an on-site green hydrogen fuel production system at the planned Valley Link Operations and Maintenance Facility (OMF) site in the City of Tracy and compare it to purchasing hydrogen from a supplier and dispensing it at the OMF. This study included the evaluation of on-site renewable energy generation and battery electric storage to support the production of green hydrogen through the most cost-effective and sustainable means.

The feasibility study lays out a path forward to progress the implementation of a green hydrogen production facility in a manner that most appropriately promotes the Authority's public agency accountability and manages risk. This includes the build out of the ultimate green hydrogen production facility in phases to leverage discretionary funding opportunities, the maturation of technology, and private sector partnerships. As a "proof of concept" demonstration project, the first phase of the project would allow the Authority to test the feasibility of producing green hydrogen to evaluate the potential use of hydrogen to power Valley Link trains. This is critical to inform the selection of the Valley Link rail vehicle technology as part of the ongoing environmental process as well as the development of the capital and operations financial plan. Before Valley Link service operations, the first phase would provide green energy to other local public transit modes and the freight industry, which are in the process of transitioning to zero emission vehicles.

As part of managing risk and maximizing the outcomes of green hydrogen production, the feasibility study recognizes the opportunity to pursue some form of public private partnership with expertise from the hydrogen production industry. This partnership could include the design, construction, financing, operations, and maintenance of the hydrogen production facility. This business model is intended to serve as not only a catalyst for private investment, but a catalyst for a green energy economy within the Northern California megaregion companioned by workforce development to create and sustain living wage jobs.

The Authority's green hydrogen production facility is a bold vision to explore the establishment of a megaregional green hydrogen hub integrating production and use by the transportation sector. While the feasibility study identifies the sizing of the production facility to meet Valley Link's initial operating segment fuel needs, the Authority recognizes the opportunity to scale up a facility to ensure that both public and private investment in a green hydrogen hub can expand the availability and reduce the cost of green hydrogen to other users. The Authority looks forward to working with its public, private and community partners to advance this vision to meet the transportation, environmental, and economic needs of the Northern California megaregion now and into the future.

Veronica Vargas

Veronica Vargas
Mayor Pro Tem, City of Tracy
Board Chair, Tri-Valley – San Joaquin Valley Regional Rail Authority

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GLOSSARY

Acronym	Full Name	Acronym	Full Name
AC	Alternating Current	NPV	Net Present Value
AEL	Alkaline Water Electrolysis	NREL	National Renewable Energy Laboratory
AHJ	Authority Having Jurisdiction	OEM	Original Equipment Manufacturers
BART	Bay Area Rapid Transit	OMF	Operations and Maintenance Facility
BESS	Battery Energy Storage System	O&M	Operations and Maintenance
BOP	Balance of Plant	Opex	Operational Expenditure
Capex	Capital Expenditure	P3	Private Public Partnership
CCA	Community Choice Aggregation	PEM	Proton Exchange Membrane
CCUS	Carbon Capture Utilization and Storage	PPA	Power Purchase Agreement
CFC	California Fire Code	PV	Photovoltaic
CI	Carbon Intensity	RECs	Renewable Energy Certificates
CSD	Compression Storage Dispensing	RO/DI	Reverse Osmosis De-Ionized
DC	Direct Current	SOC	State of Charge
FCEB	Fuel Cell Electric Buses	SOEC	Solid Oxide Electrolysis Cell
FCEV	Fuel Cell Electric Vehicle	TCF	Trillion Cubic Feet
HTEC	Hydrogen Technology and Energy Corporation	TRL	Technology Readiness Level
ICA	Integration Capacity Analysis	RNG	Renewable Natural Gas
LCFS	Low Carbon Fuel Standard	SMR	Steam Methane Reforming
LCOE	Levelized Cost of Electricity	ZEV	Zero Emission Vehicle
LCOH	Levelized Cost of Hydrogen		
NFPA	National Fire Protection Association		

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EXECUTIVE SUMMARY

The purpose of this feasibility study was to evaluate the physical and financial feasibility of developing an on-site hydrogen production system at the Valley Link Tracy Operation and Maintenance Facility (OMF) site and compare it to purchasing hydrogen from a supplier and dispensing it at the OMF. The first step in this feasibility study was to select an on-site hydrogen production technology based on key criteria such as, carbon intensity, feedstock availability, pollutant emissions, and technology readiness. *Electrolytic hydrogen production using renewable electricity* was selected as it best fit these key criteria. Electrolysis uses electricity to split water molecules into hydrogen and oxygen. To ensure the hydrogen produced is low-carbon, the electricity must come from a renewable source like solar or wind. To then answer the question of whether to produce hydrogen onsite using electrolysis or purchase hydrogen, the feasibility study needed to answer various questions associated with the onsite production option as shown in Figure ES-1. These other questions included: 1) what are the sources of renewable electricity for electrolysis, and 2) what is the appropriate mix of grid electricity and battery energy storage systems to ensure 24/7/365 operation of the onsite production facility. Finally, a financial model that includes technical constraints and calculations was built to understand the operational and financial feasibility of onsite electrolytic hydrogen production and compare to hydrogen purchased from a supplier.

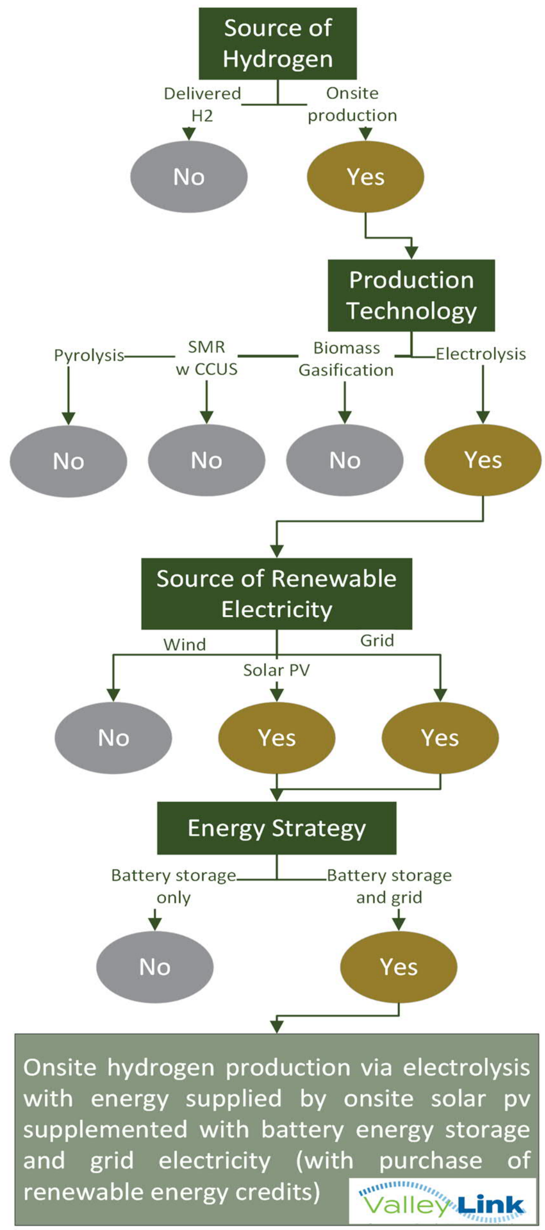


Figure ES-1: Valley Link decision tree on evaluating hydrogen sources for a hydrogen fuel cell train

Three project phases were envisioned in this feasibility study for the Valley Link hydrogen production project and are shown in Table ES-1. The three project phases align with the build-out of the Valley Link system and also limits risk by allowing for three GO/NO-GO decision gates before each phase. Each phase can then also take advantage of learning in each phase as well as likely significant market/technology maturation. Phase 1 would be critical for allowing Valley Link to test the feasibility of producing hydrogen for use in Valley Link fuel cell trains. In the meantime, it would provide low-carbon electrolytic hydrogen not currently available for sale to transit agencies in northern California.

Table ES-1: Project Phasing

Project Phase	Phase Description	Operation Date	Incremental H_2 Demand (tonnes-H_2/year)	Total H_2 Demand (tonnes-H_2/year)
Phase 1	In Phase 1, the production facility provides hydrogen to local transit agencies and freight	2025	229	229
Phase 2	In Phase 2, the production facility is scaled up to also meet the initial demand from Valley Link trains	2027	715	944
Phase 3	In Phase 3, the production facility is scaled up to meet the mature demand from Valley Link trains	2030	429	1,373

Figure ES-2 schematically shows the various activities before each GO/NO-GO decision gate. The first GO/NO-GO decision gate relates to Valley Link's decision to pursue detailed planning and design activities required prior to developing a Request For Proposals (RFP). The second GO/NO-GO decision gate relates to Valley Link deciding whether to develop and release an RFP. The third GO/NO-GO decision gate occurs after Valley Link staff review proposals and is a decision whether to pursue entering into a contract with the winning proposer.

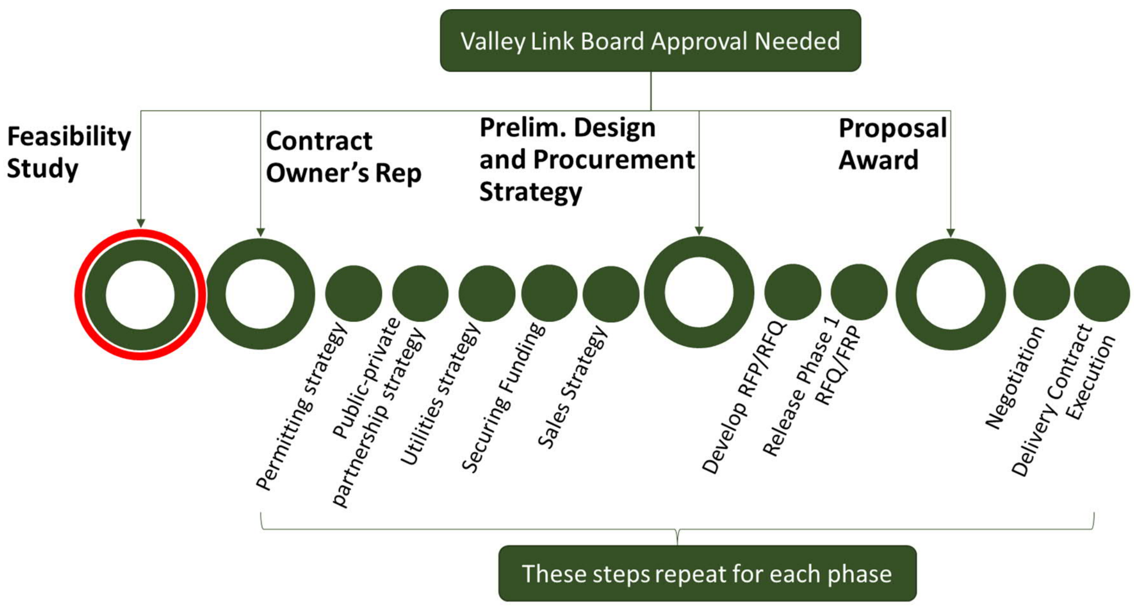


Figure ES-2: Valley Link board approval gates and the various activities occurring before each gate

The feasibility study indicated in Figure ES-2 is the feasibility study contained in this document. The main output from this feasibility study is to 1) recommend the best hydrogen supply option, 2) determine equipment sizing in the different project phases, and 3) perform a preliminary review on each of the planning activities identified before the GO/NO-GO to develop and release an RFP. This feasibility study used various renewable energy modeling tools and hydrogen equipment sizing methods to integrate this technical information into financial models that allowed for analyzing different scenarios to inform the size of equipment in each project phase. Based on these analyses, it is recommended that Valley Link pursue the ***onsite electrolytic hydrogen production concept*** given the cost-effective carbon emission reduction provided, the opportunity for revenue generation, the significant funding opportunities from recent announcements related to hydrogen, and the significant private sector and state interest in electrolytic hydrogen production projects. The optimum equipment size in each phase is summarized in the table below, however, another optimal rollout and equipment sizing may result from various external constraints not considered in this study (e.g., funding, etc.). For example, if there were funding limitations in the first phase, the size of the on-site renewable electricity system could be reduced and moved to a future phase. Table ES-2 also includes the estimated capital expenditure and operation expenditure associated with each phase.

Table ES-2: Project costs by phase subject to funding limitations

	Equipment Installed in Each Phase and Corresponding CapEx/OpEx						
Project Phase	H2 Production Facility Size (tonnes/day)	Solar Facility Size (MW)	BESS Facility Size (MW/MWh)	Incremental CapEx ($M)	Total CapEx ($M)	Incremental OpEx ($M/y)	Total OpEx ($M/y)
Phase 1	1	12	5 / 4	$32M	$32M	$1.8M	$1.8M
Phase 2	2.9	If more land, increase to max amount	Increase to appropriate for increased Solar	$24.8M	$56.8M	$5.1M	$6.9M
Phase 3	1.7	If more land, increase to max amount	Increase to appropriate for increased Solar	$10.3M	$67.1M	$2. 6M	$9.5M

It is recommended that the electricity be supplied by on-site renewable electricity with battery energy storage supplemented by the California grid to ensure 24/7/365 operation. The onsite renewable energy production potential was most cost-effective coming from solar rather than wind. The electrolysis must be supplied with 100% renewable electricity, e.g., any renewable electricity not produced on-site would need to be supplemented with Renewable Electricity Certificates (REC)[1]. Further research is required to determine the best source of water for this project. The water intensity for electrolysis is similar to producing diesel fuel, but given current and probable future drought conditions in California, it is recommended that alternative water sources such as the City of Tracy's recycled water system or upper-aquifer groundwater wells, be considered as potential sources. The on-site electrolytic hydrogen production also showed significant potential for revenue from excess hydrogen and electricity sales, which can drive down Valley Link operations and rider costs. Increasing the capability of Valley Link to produce onsite renewable electricity in greater amounts will be important for driving down production costs. Although the onsite production option carries more risk than simply having hydrogen delivered and then dispensing it, this additional risk can be mitigated through developing a public-private partnership strategy and carefully selecting an Owner's Representative with the requisite expertise in the hydrogen sector. With these broad risk mitigation strategies, the benefits outweigh the risks.

[1] Or another pathway for securing 100% renewable electricity, this study analyzed this pathway. It is important to note that sale of Low Carbon Fuel Standard credit is an important revenue source for the financial models evaluated and the LCFS regulation has a single carbon intensity for the entire California electricity grid, i.e., it is not broken down by utility service territory. Therefore, this study has used the LCFS electric grid carbon intensity in its analyses.

1. INTRODUCTION - THE EVOLVING HYDROGEN SECTOR

1.1. Global Hydrogen Supply and Demand

Countries and regions around the globe are developing supply pathways and end-use applications for hydrogen to power their clean economies. The number of countries with policies that directly support investment in hydrogen technologies is increasing, and so is the number of sectors being targeted. According to the Hydrogen Council, as of January 2020, 18 governments, whose economies account for more than 70% of global gross domestic product (GDP), have developed national hydrogen strategies and 228 hydrogen projects across the value chain have been announced as of February 2021[2]. Of these, 17 are giga-scale production projects (i.e., more than 1 GW for renewable sourced and over 200 thousand tons a year for low-carbon hydrogen)[3].

Figure 1 shows the global production of hydrogen by energy source in 2018. The total global production of hydrogen in 2018 was 144 million metric tonnes (Mt), of which 67% of production was deliberate, and 33% was produced as a by-product of industrial processes[4].

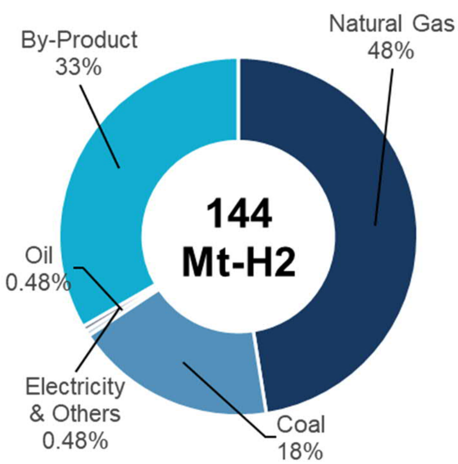
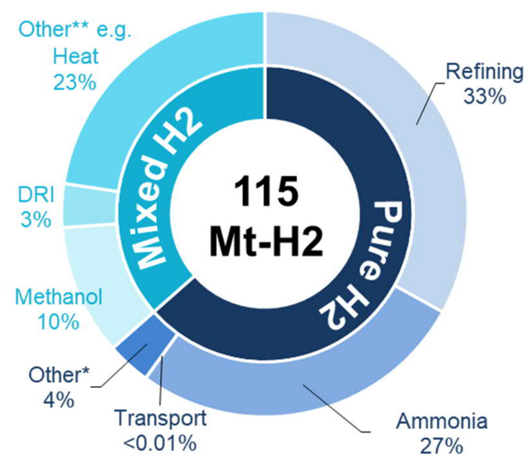


Figure 1: Global hydrogen production by energy source (2018)[4]



* Chemicals, metals, electronics, and glass making industries

** Generation of heat from steel works arising gases and by-product gas from steam crackers

Figure 2: Global hydrogen demand by end-use (2018)[4]

Most of the hydrogen produced today is made from fossil fuels. In 2018, 48% of total hydrogen produced worldwide was derived from natural gas. Hydrogen production from coal, which is mostly

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[2] Hydrogen Council. (2020). *Path to hydrogen competitiveness: A Cost perspective*. Retrieved from https://hydrogencouncil.com/wp-content/uploads/2020/01/Path-to-Hydrogen-Competitiveness_Full-Study-1.pdf

[3] Hydrogen Council. (2021). *Hydrogen Insights 2021 Report*. Retrieved from https://hydrogencouncil.com/wp-content/uploads/2021/02/Hydrogen-Insights-2021-Report.pdf

[4] IEA. (2019). *The Future of Hydrogen*. Retrieved from https://www.capenergies.fr/wp-content/uploads/2019/07/the_future_of_hydrogen.pdf

due to its popularity as an energy source in China, accounted for 18% of production. Electricity and oil each contributed 0.48%, and the balance was produced as a by-product of another industrial process such as sodium chlorate or chlor-alkali production. Global demand for hydrogen in 2018, displayed in Figure 2, was 115 Mt-H_2.

Applications utilizing pure hydrogen accounted for 60% (69 Mt-H_2) of all demand. Pure hydrogen for oil refining and ammonia production were the most common end uses, accounting for 33% and 27% of total demand, respectively. The remainder of pure hydrogen use in 2018 included transport, chemicals, metals, electronics, and glass-making industries.

Demand for mixed hydrogen covered 40% (46 Mt-H_2) of the market, with other end uses such as heat generation from steelworks arising gases and by-product gas from steam crackers accounting for 23% of total demand. Other uses of mixed hydrogen included the production of methanol and direct reduced iron steel (DRI).

Interest in hydrogen as part of dialogue regarding global energy transformation is growing rapidly, with projections indicating at least a tenfold increase in demand in the coming decades. Since 2010, global demand for hydrogen has grown by a moderate 28%. However, studies indicate that hydrogen, backed by the right incentives, investments, and policies, could provide between 18% and 24% of global energy demand by 2050[4], with some countries being much higher. The five largest consumers of hydrogen are expected to be China, the EU, Japan, South Korea and California, based on their existing strategies and targets.

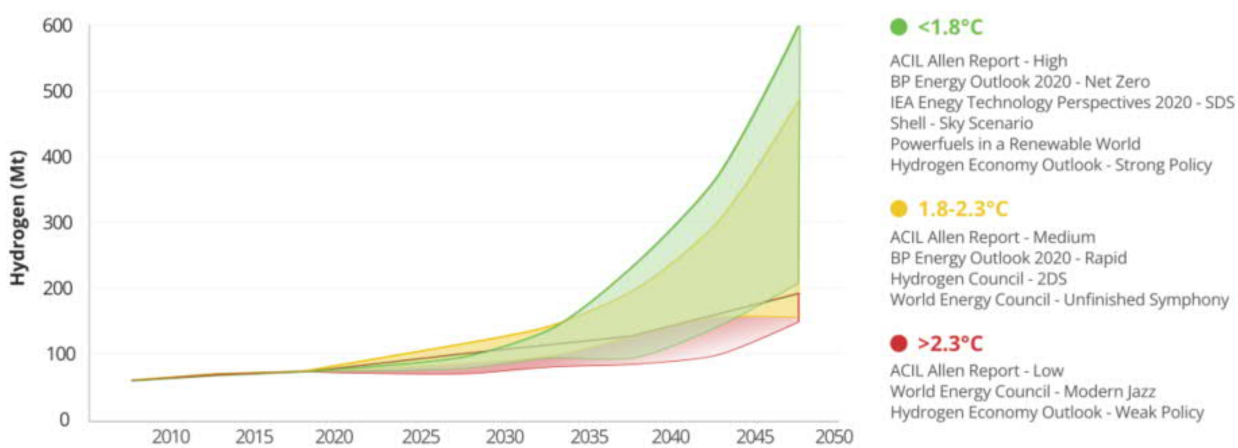

Figure 3: Ranges of Estimates for Annual Global Hydrogen Demand capable of meeting 2050 global warming targets between 1.8°C and 2.3°C [5]

Several major energy players, including Japan, South Korea, China, and the US, have released national strategies or announced significant investments in hydrogen and developing hydrogen economies. This recent interest is driven by multiple factors and forces but some of the most important include:

- The movement toward decarbonization across all sectors;
- The increasing penetration of variable renewable energy sources;
- The uncertainty of future investments in the oil and gas sector; and

[5] https://www.worldenergy.org/assets/downloads/Innovation_Insights_Briefing_-_Hydrogen_on_the_Horizon_-_Ready%2C_Almost_Set%2C_Go_-_July_2021.pdf

- The rapidly falling costs of hydrogen production technologies.

Unlike previous rounds of excitement around hydrogen, today's interest is driven by a belief that hydrogen will be an essential tool to address climate change. While there are still many challenges to overcome, the message is clear: hydrogen will have a critical role in a carbon-neutral future, and most of the world's largest economies are already developing the strategies and investments required to make this a reality.

1.2. National Hydrogen Supply and Demand

In 2020, 11.4 Mt of hydrogen was consumed in the US, with 94.7% of hydrogen demand being used as a feedstock for industrial processes such as oil refining, ammonia production, and methanol production[6]. Despite the dominance of hydrogen demand from industrial processes, using hydrogen as a fuel for fuel cell vehicles and equipment is gaining momentum across the US and primarily in California as fuel for zero-emission vehicle technology (ZEV). As of 2022, the fuel cell transportation market consists of 13,305 fuel cell electric vehicles (FCEV) in the US, 76 operational fuel cell electric buses (FCEB) in California, ~35,000 deployments of fuel cell forklifts, 63 hydrogen fueling stations in development or operation, and over 120 material-handling fueling stations[7],[8].

The majority of hydrogen produced in the US comes from carbon-intensive processes, including steam methane reformation (SMR), which accounts for 77% of national production and by-product hydrogen from refining operations accounting for 23% of production[9]. Figure 4 displays the location and production volume of current carbon-emitting hydrogen production facilities throughout the US. The size and location of hydrogen production facilities correspond to the oil refinery and ammonia production facilities per region.

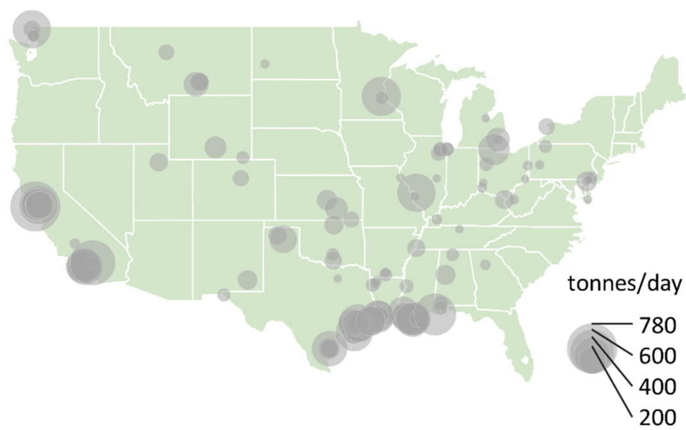

Figure 4: Current US grey hydrogen production capacity

Numerous renewable hydrogen production projects and technology are emerging to support future demand projections of hydrogen and low-carbon fuel pathways. Hydrogen production from SMR paired with carbon capture utilization and storage (CCUS) and electrolysis are of particular interest

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[6] McKinsey & Company (2020). *Road Map to a US Hydrogen economy*. Retrieved from: https://static1.squarespace.com/static/53ab1feee4b0bef0179a1563/t/5e7ca9d6c8fb3629d399fe0c/1585228263363/Road+Map+to+a+US+Hydrogen+Economy+Full+Report.pdf
[7] Ibid.
[8] CaFCP (2021). *By the Numbers–FCEV Sales, FCEB, & Hydrogen Station Data*. Retrieved from:https://cafcp.org/by_the_numbers
[9] McKinsey & Company (2020). *Road Map to a US Hydrogen economy*. Retrieved from: https://static1.squarespace.com/static/53ab1feee4b0bef0179a1563/t/5e7ca9d6c8fb3629d399fe0c/1585228263363/Road+Map+to+a+US+Hydrogen+Economy+Full+Report.pdf

in the US and have been demonstrated and announced across the nation.

1.3. Future Hydrogen Supply and Demand

The US National Hydrogen Roadmap, completed by McKinsey & Company in 2020, estimated that hydrogen demand could increase to 20 Mt – 63 Mt by 2050, which is 76% - 453% higher than current demand and 1% - 14% of total energy demand[10]. Fuel for transportation is the largest driver for the ambitious hydrogen demand scenario, accounting for 27 Mt of hydrogen and 57% of the total hydrogen demand for new markets in the ambitious scenario, compared to the 3 Mt projected for the baseline scenario. The following map shows planned hydrogen production plants North America.

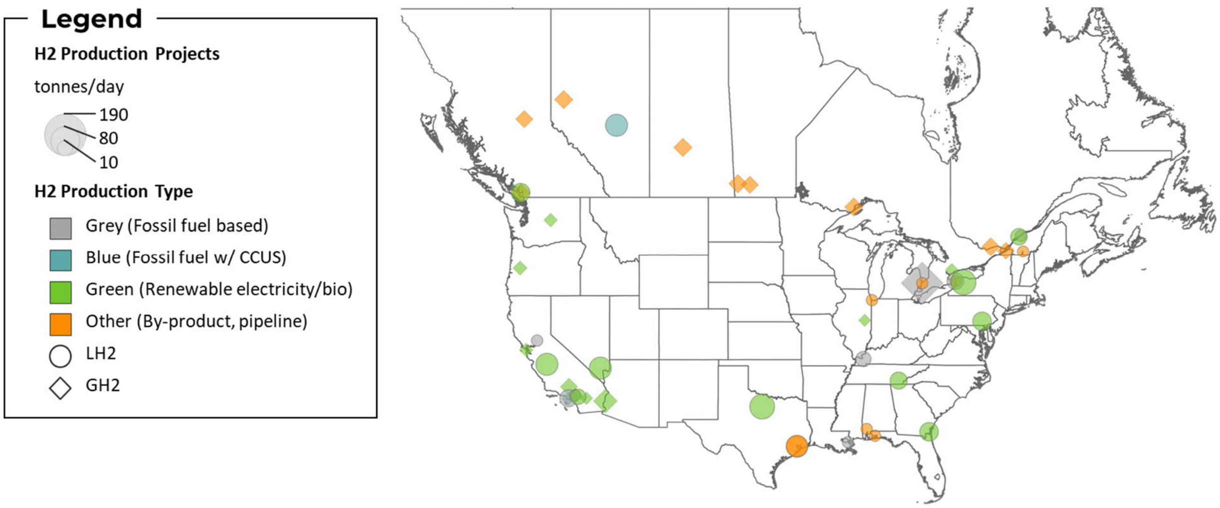

Figure 5: Hydrogen Production Plants in North America not including hydrogen produced and consumed onsite

The remaining new markets for hydrogen include fuel for residential and commercial buildings, fuel for industry, power generation and grid balancing, and new feedstock. The annual low-carbon hydrogen production potential from electrolysis produced by wind, solar, and biomass resources was estimated for each region in the US by the National Renewable Energy Laboratory (NREL) (Figure 6) to identify which states are best positioned to produce low carbon hydrogen[11]. California was estimated to be one of the top 10 producers of low-carbon hydrogen from renewable resources, with a value of 238 Mt-H2/year.

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[10] McKinsey & Company (2020). *Road Map to a US Hydrogen economy*. Retrieved from: https://static1.squarespace.com/static/53ab1feee4b0bef0179a1563/t/5e7ca9d6c8fb3629d399fe0c/1585228263363/Road+Map+to+a+US+Hydrogen+Economy+Full+Report.pdf
[11] M. Melania, et al. (2013). *Resource Assessment for Hydrogen Production*. Retrieved from: https://www.nrel.gov/docs/fy13osti/55626.pdf

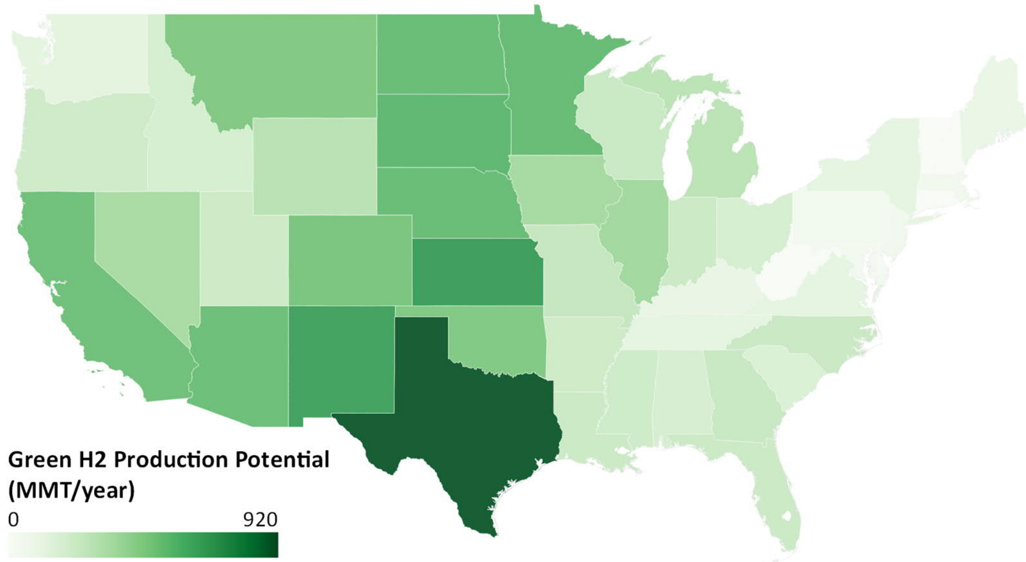


Figure 6: Hydrogen production potential from wind, solar, and biomass resources

2. HYDROGEN PRODUCTION PATHWAYS

2.1. Overview

Today, most hydrogen generated around the world is made through steam methane reforming (SMR), in which natural gas and high-temperature steam react to produce hydrogen and CO2. This pathway is not considered low-carbon because of the CO2 produced; however, if carbon capture utilization and storage (CCUS) is employed, the emissions can be massively reduced, resulting in low-carbon hydrogen.

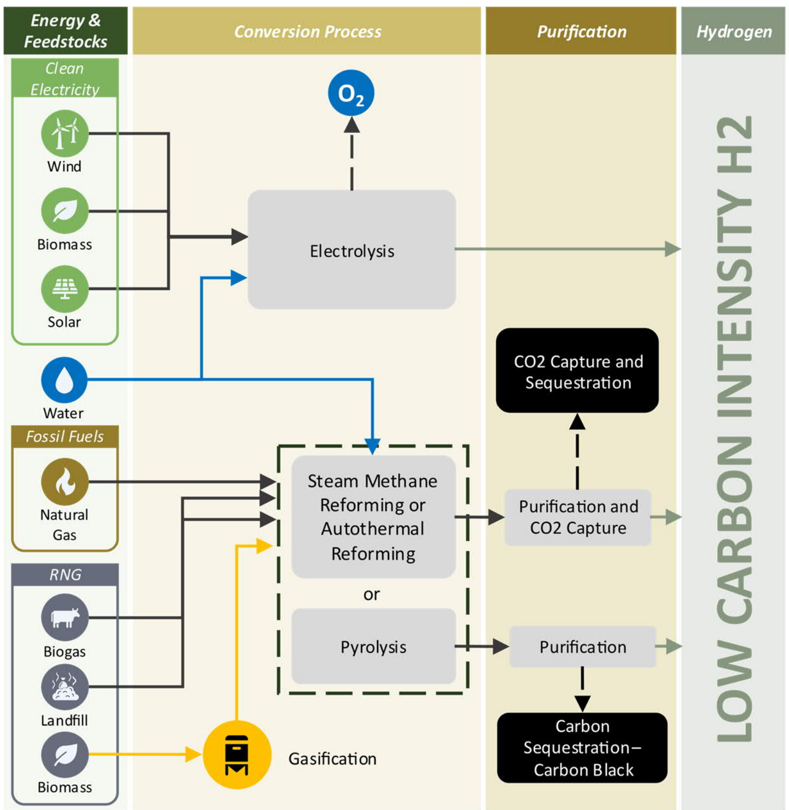


Figure 7: Hydrogen production pathways

Pyrolysis is an alternative hydrogen production pathway that also uses natural gas as a feedstock. In this case, hydrogen is produced by decomposing natural gas in an environment without oxygen into its two constituents: hydrogen, which is output as a gas, and carbon black, which is output as a solid. Since CO2 is not produced in the reaction, the emissions from this pathway are limited, and the hydrogen produced is considered low carbon.

The emissions related to SMR and pyrolysis can be further reduced if renewable natural gas (RNG) is used as a feedstock instead of fossil-based natural gas. The RNG could be produced from biomass feedstocks such as landfills, municipal waste, wastewater treatment, manure, or wood waste. Using biomass as a feedstock can also lead to low-carbon hydrogen if gasification is used rather than SMR or pyrolysis. Biomass gasification produces hydrogen as well as other by-products, and if the CO2 emissions are captured and stored, a low-carbon hydrogen is produced.

A final pathway that is rapidly growing around the world is electrolysis, in which electricity is used to split water into hydrogen and oxygen. The hydrogen produced can be low carbon, but the resulting emissions are heavily dependent on the carbon intensity (CI) of the electricity. If renewable sources, such as wind and solar, are used, the CI of the hydrogen will be zero. However, if the electricity is generated by high-emitting sources like coal, the CI of the hydrogen can be very high.

2.2. Costs

Figure 8 shows the estimated cost to produce hydrogen via electrolysis, SMR with CCUS, pyrolysis and biomass gasification based on estimated technology capital expenditure (Capex) and operating expenditure (Opex), including feedstock costs specific to California. Electrolysis from renewable sources can produce zero-carbon hydrogen. Electrolysis can also use electricity directly from the grid, however based on the average CI of California's grid, it would not produce low-carbon hydrogen. Electrolysis using electricity derived from wind and solar was modelled based on an assumed levelized electricity price of \$30/MWh with a utilization of 40% for wind and 30% for solar. Assumptions were based on data collected from Power Purchase Agreements (PPAs) by Lawrence Livermore National Labs. If battery energy storage systems (BESS) are added, the levelized cost of electricity increased to \$50/MWh, and the utilization increased to 57% and 47% for wind and solar, respectively. In both cases, the use of BESS increased the estimated cost of hydrogen. These BESS adders are typical of 4-hour storage systems, but low-cost, longer-duration storage systems may be able to maintain a similar or lower adder for more utilization, thereby reducing hydrogen production cost.

Hydrogen production via SMR with CCUS, and pyrolysis were modelled using natural gas and RNG as the major feedstock. Natural gas was assumed to cost \$4/MMBtu while RNG costed \$15/MMBtu. As a result, the cost of hydrogen from RNG is significantly higher than fossil-derived natural gas. Hydrogen production via biomass gasification was modeled using woody biomass (30% moisture) as the feedstock. The price of this feedstock used for this calculation was \$60/dry tonne. The reason why the biomass gasification system is lower cost that the SMR+CCS cases is mainly due to the absence of a CCS system in the biomass gasification system since the biomass is carbon-neutral. The biomass gasification system assumed is very large and is not typically considered for a small project (<100 tonne/d hydrogen production) because economies of scale are significant (i.e., a small plant would be much more expensive).

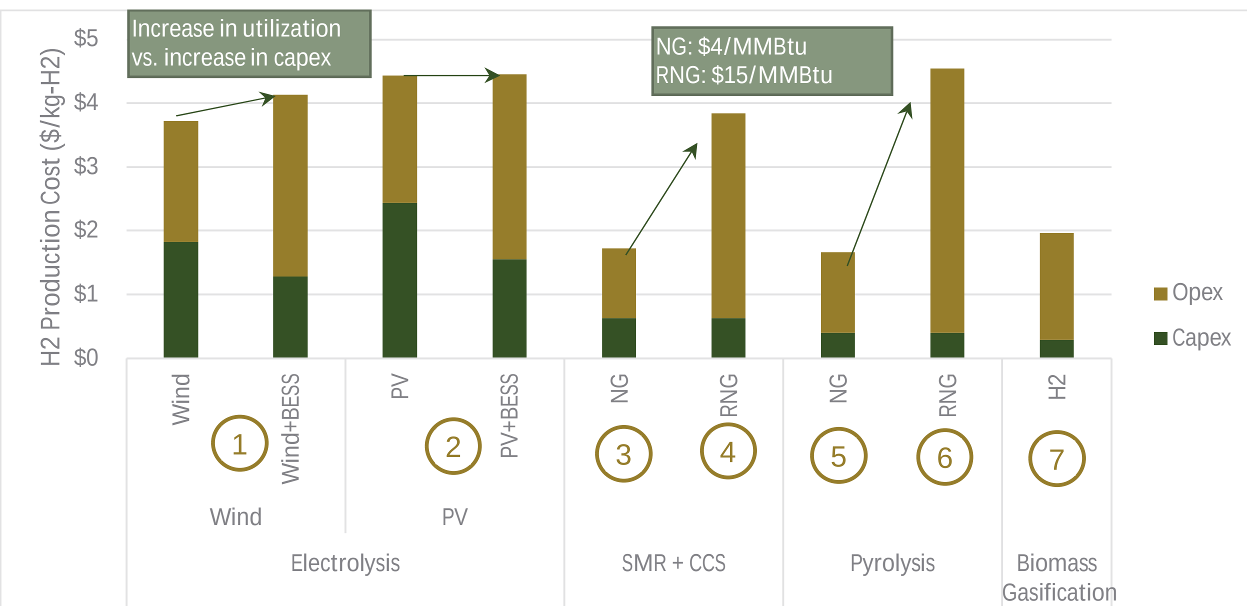


Figure 8: Hydrogen cost by production pathway for large scale facility. Cost shows production only, no distribution or dispensing.

The cost of hydrogen produced via electrolysis will vary depending on three main factors: cost of electricity, the capital cost of the electrolyzer, and utilization (actual average operating capacity vs. total capacity available). Figure 9 shows how these factors impact the cost of hydrogen. Overall, the biggest driver is electricity cost. As electricity price drops from $120/MWh to $20/MWh, the cost of the resulting hydrogen reduces significantly.

The hydrogen production cost is sensitive to electrolyzer Capex at low utilizations, but at higher utilization, the electricity cost still dominates. If the electricity price is low, Capex reduction begins to have a greater impact on reducing hydrogen production costs (e.g., an 83% reduction in electricity price results in 80% hydrogen production cost reduction while an 88% reduction in Capex produces a 50% reduction at low electricity prices and a 17% reduction at high electricity prices). In order to reach a $1/kg hydrogen production cost, high utilization and low electricity costs will be required (e.g., $0.02/kWh electricity price with Capex of $100/kW and utilization approaching 85+% will require renewable electricity supplied by a hybrid PV+Wind+BESS power plant).[12]

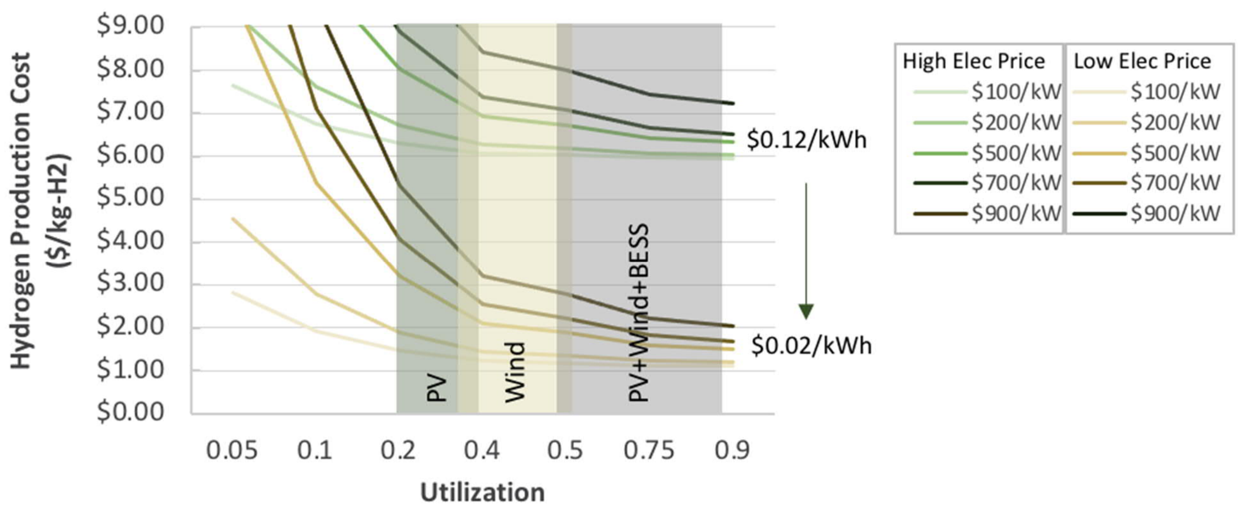


Figure 9: Electrolysis hydrogen production cost sensitivity to electrolyzer cost, electricity price, and utilization

2.3. Carbon and Water Intensity

The estimated CI of hydrogen produced via each pathway is shown in Figure 10. In the 2021 Infrastructure Investment and Jobs Act (IIJA), the definition of “clean hydrogen” or “low-carbon hydrogen” is 2 kgCO2/kg-H2 which translates to ~14 gCO2e/MJ[13]. As shown in Figure 10 below, only electrolysis from renewables, and SMR, pyrolysis, or gasification using renewable feedstocks qualifies as low-carbon hydrogen. Using RNG as a feedstock can result in negative emissions if CCUS is employed because emissions that would otherwise have been released naturally will be captured and used or sequestered instead. Although the RNG pathway has a higher cost, as shown in Figure 8, there may be sufficient economic benefit if the cost of carbon is high enough.

[12] Lane et al. (2021). Forecasting renewable hydrogen production technology shares under cost uncertainty. Retrieved from: https://www.sciencedirect.com/science/article/abs/pii/S0360319921021558

[13] https://www.babstcalland.com/news-article/infrastructure-bill-provides-billions-in-funding-for-hydrogen-and-carbon-capture-utilization-and-storage/

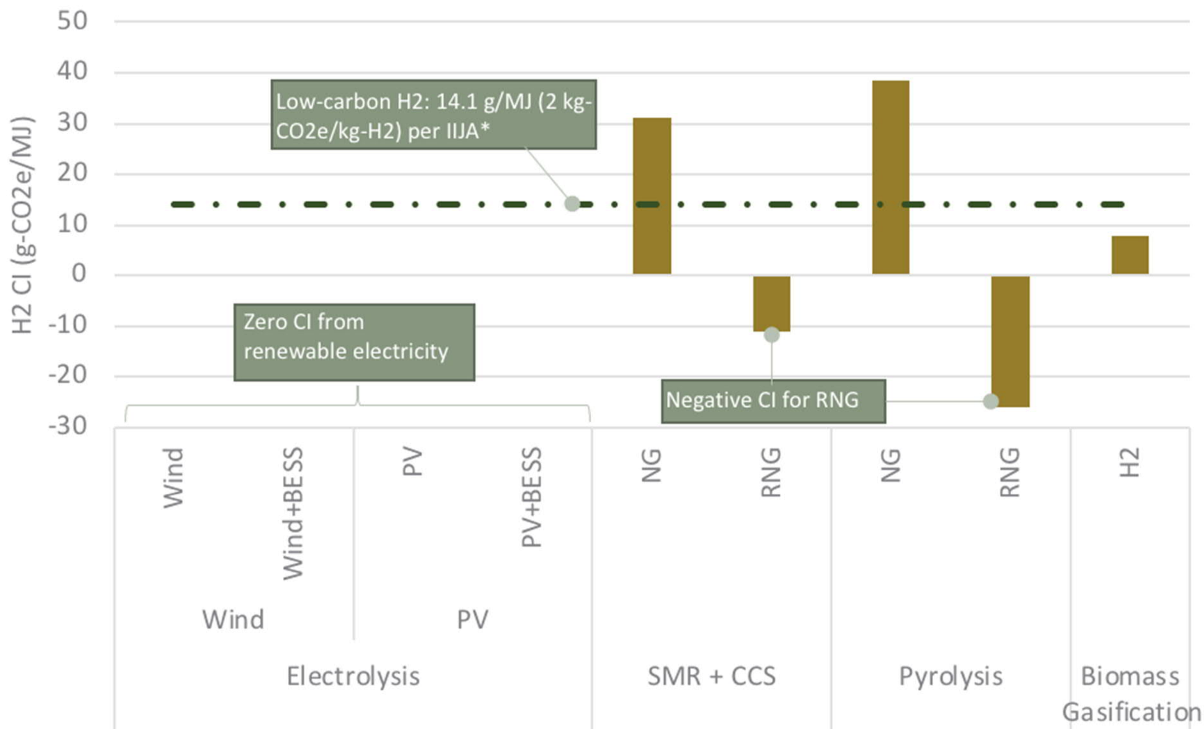


Figure 10: Hydrogen carbon intensity by production pathway

In addition to cost and GHG emissions, it is important to consider the water requirements of hydrogen production. Electrolysis and SMR both require significant quantities of water to produce hydrogen. About 18 L of freshwater is required for every 1 kg of H_2 and 8 kg of O_2 produced, and about 9.5L of wastewater is produced for every 1 kg of hydrogen. The water used in electrolysis must be of high purity so as not to damage the electrolyzer (ASTM Type II, <1µS/cm). Some electrolyzer projects are using saltwater as feedwater[14]. The wastewater produced contains only those contaminants in the water input to the electrolyzer and is traditionally disposed of in a storm sewer. The wastewater could potentially be recycled and re-used as feed, however an additional water purification system would be required to treat it and this has never been done in an electrolysis facility to date.

Figure 11 shows a comparison of water consumption for different hydrogen production processes as well as several conventional oil and gas production. There is a wide-range of variation in the literature but for the purposes of producing a transportation fuel such as gasoline, electrolytic hydrogen can be competitive in terms of water consumption.

[14] https://www.lhyfe.com/our-production-units/renewable-hydrogen-made-in-vendee/

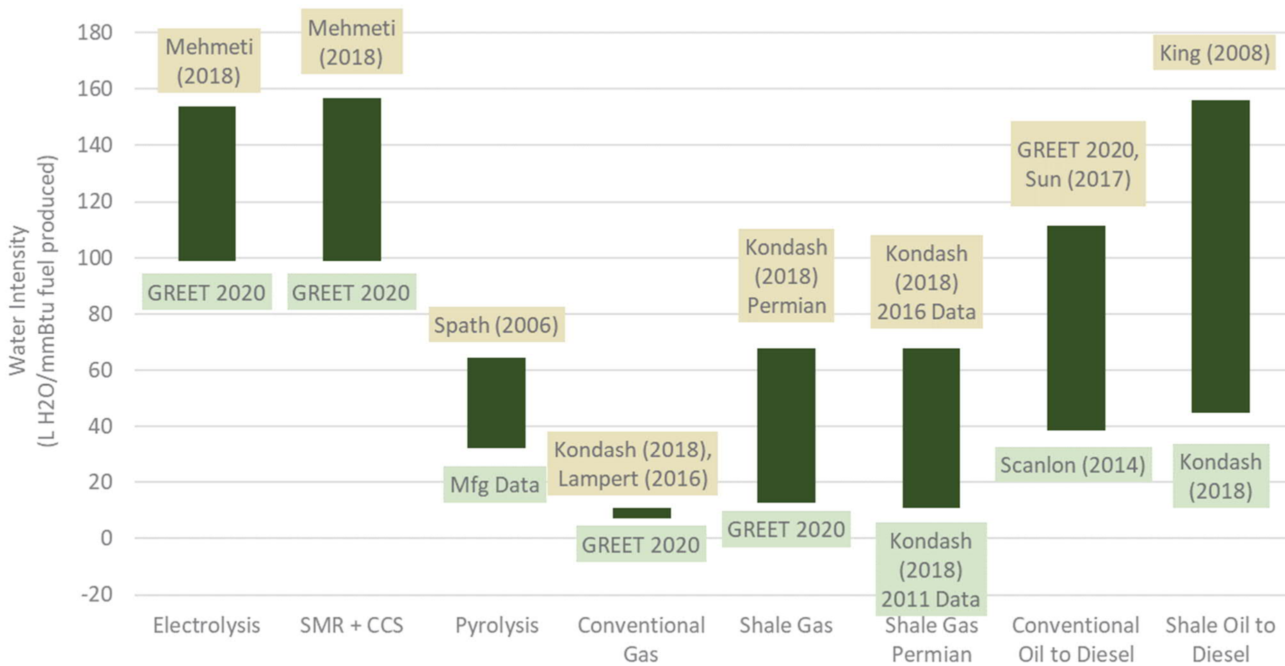


Figure 11: Water consumption hydrogen and fossil fuel production pathways[15,16,17,18,19,20,21,22]

[15] Spath, P. et al. (2006). Biomass to Hydrogen Production Detailed Design and Economics Utilizing the Battelle Columbus Laboratory Indirectly-heated Gasifier. Retrieved from: https://www.nrel.gov/docs/fy05osti/37408.pdf

[16] Kondash, A. et al. (2018). The intensification of the water footprint of hydraulic fracturing. Retrieved from: https://advances.sciencemag.org/content/4/8/eaar5982.

[17] Mehmeti, A. et al. (2018). Life Cycle Assessment and Water Footprint of Hydrogen Production Methods: From Conventional to Emerging Technologies. Retrieved from: https://www.mdpi.com/2076-3298/5/2/24

[18] Argonne National Laboratory (2020). The Greenhouse gases, Regulated Emissions, and Energy use in Technologies Model. Retrieved from: https://greet.es.anl.gov/greet_1_series

[19] King, C. et al. (2008). Water Intensity of Transportation. Retrieved from: https://pubs.acs.org/doi/10.1021/es800367m.

[20] Scanlon, B.R. et al. (2014). Comparison of Water Use for Hydraulic Fracturing for Unconventional Oil and Gas versus Conventional Oil. Retrieved from: https://pubs.acs.org/doi/10.1021/es502506v

[21] Lampert, D. et al. (2016). Wells to wheels: water consumption for transportation fuels in the United States. Retrieved from: https://www.osti.gov/pages/biblio/1392949

[22] Sun et al. (2017). Estimation of US refinery water consumption and allocation to refinery products. Retrieved from: https://www.sciencedirect.com/science/article/pii/S0016236117309511#f0040

2.4. Production Pathway Comparison

In down selecting a hydrogen production pathway for the Valley Link project, a number of evaluation criteria were identified, and the different production pathways were compared based on these five criteria. The table below summarizes whether each production pathway meets or does not meet each criteria. Any production pathway that did not meet one of the criteria was eliminated from consideration for this project.

Table 1: Evaluation of production technologies based on key criteria

	1. Electrolysis (Wind)	2. Electrolysis (PV)	3. SMR + CCS (NG)	4. SMR + CCS (RNG)	5. Pyrolysis (NG)	6. Pyrolysis (RNG)	7. Biomass Gasification
"Low-Carbon" as defined by IIJA	√	√	×	√	×	√	√
Feedstock Availability	√	√	√	√/ ×	√	√/ ×	√ / ×
No CCUS	√	√	√	×	√	√	×
No pollutant Emissions	√	√	×	×	×	×	×
High TRL	√	√	√	√	√	×	√

Qualifies as "low-carbon" hydrogen according to infrastructure bill

As explained above the new "low-carbon" definition of 14 gCO2e/MJ from the IIJA eliminates any of the production pathways that utilize fossil-based natural gas. Eliminate pathways 3 and 5.

Availability of feedstocks

The renewable feedstocks for electrolysis include solar and wind, and for the other pathways the renewable feedstocks include biomass and renewable natural gas. All of these feedstocks are available in California, however solar and wind have higher availability potential since they do not rely on a biomass or renewable natural gas supply chain. The supply of biomass and renewable natural gas feedstocks are limited. Currently, there is sufficient availability but in the future as these resources are more fully utilized, availability could be an issue and impact price. For example, current California natural gas demand is ~2 TCF/yr while total RNG potential is ~0.2 TCF/yr[23]. Even in the California Air Resources Board modeling of different energy futures for analysis of how to achieve climate goals, in the high CCS scenario for 2045 carbon neutrality in California, there is still ~0.6

[23] https://www.icf.com/insights/energy/design-principles-for-renewable-gas

TCF/yr demand from the natural gas system[24].

Does not require carbon capture and sequestration

For SMR, CO_2 is produced and emitted during the production process. To qualify as “low-carbon hydrogen” the CO_2 produced must be captured and sequestered in the ground. Although CCS is technically feasible, favourable geological formations (*e.g.* depleted oil and gas formations, saline formations, coal beds, basaltic rock) must be near to the point of capture. Although the valley is located in a large sedimentary basin which could potentially offer sequestration potential, it is expected that concerns around the water table and public acceptance would discourage any producer from sequestering captured carbon dioxide in the Valley. Eliminate pathways 4 and 7.

For pyrolysis, the carbon component of the organic feedstock is outputted as a solid in the form of carbon black. Carbon black is a solid material that can be used as a feedstock in applications such as automobile tires, ink, and carbon paper. Carbon black locks the carbon in the product for its lifetime rather than emitting it to the atmosphere, so no capturing or sequestration is required.

No pollutant emissions

Criteria pollutant emissions are another major consideration. Electrolysis is the only option that has zero criteria pollutant emissions. Given California’s struggle to meet federal Ambient Air Quality Standards, the State has implemented more and more stringent regulations on criteria pollutant emissions. The San Joaquin Valley has severe air quality issues, so using a zero emissions technology will be important.

High technological readiness level (TRL)

Electrolysis has been deployed as a commercial technology, with global capacity today at ~300MW with projects under development expected to bring up capacity to 54 GW in 2030.[25] Pyrolysis is at a lower TRL level with no pilot or commercial plants in operation in North America. There is one plant in Alberta, Canada using thermal pyrolysis of natural gas, however it was designed to produce carbon black not hydrogen. Today, several companies are developing pyrolysis as a method of hydrogen production, however it has not yet been deployed at a pilot or commercial scale. Eliminate pathway 6.

The remaining production pathways, 1 and 2, are hydrogen production from electrolysis using solar and wind power, respectively.

[24] https://ww2.arb.ca.gov/sites/default/files/2020-10/e3_cn_final_report_oct2020_0.pdf
[25] https://iea.blob.core.windows.net/assets/e57fd1ee-aac7-494d-a351-f2a4024909b4/GlobalHydrogenReview2021.pdf

3. HYDROGEN PRODUCTION FEASIBILITY

The feasibility study to be investigated is a hydrogen production facility using electrolysis powered by renewable energy produced on-site (as much as possible). Three phases to the project were defined and are shown in Table 2.

Table 2: Project Phasing Definitions

Project Phasing	Phase Description	Unit	Value
FCEBs - Phase 1 - Deployment Year	In Phase 1, the production facility provides hydrogen to local transit agencies and freight	Year	2025
FCEBs - Phase 1 - Weekday Demand		kg-H2/day	1,000
FCEBs - Phase 1 - Annual Demand		MT-H2/year	229
Initial IOS[26] - Phase 2 - Deployment Year	In Phase 2, the production facility is scaled up to also meet the demand from Valley Link trains in the Initial IOS	Year	2027
Initial IOS - Phase 2 - Additional Weekday Demand		kg-H2/day	2,500
Initial IOS - Phase 2 - Additional Annual Demand		MT-H2/year	715
Mature IOS - Phase 3 - Deployment Year	In Phase 3, the production facility is scaled up to meet the demand from Valley Link trains in the Mature IOS	Year	2030
Mature IOS - Phase 3 - Additional Weekly Demand		kg-H2/day	1,500
Mature IOS - Phase 3 - Additional Annual Demand		MT-H2/year	429

Based on these levels of demand in these years, the electrolytic hydrogen production facility feasibility study was investigated in the following ways:

1) Understand the electricity (Section 4) and water (Section 5) requirements
2) Understand the limitations (if any) of on-site renewable electricity production and requirements for energy storage (Section 4)
3) Understand what a grid interconnection (if needed) requires (Section 4)
4) Understand what an electrolytic hydrogen production facility looks like (Section 5)
5) Develop a financial model based on discussions with electrolyzer equipment manufacturers about budgetary pricing, performance, and available estimates to understand the feasibility of the electrolytic hydrogen production facility (Section 6)

[26] "IOS" is Initial Operating Segment between Dublin/Pleasanton BART Station and Mountain House

4. ON-SITE RENEWABLE ENERGY PRODUCTION

The electricity demand on an annual basis for the different project phases are shown Table 3 below.

Table 3: Project phases electricity requirements (excluding any additional offtake opportunities)

Phases	Annual Incremental Demand (MT-H2/year)	Annual Incremental Electricity for Production Facility (GWh/yr)	Annual Total Electricity for Production Facility (GWh/yr)
1 Transit Buses	229	13.3	13.3
2 Initial IOS[27]	715	41.5	54.8
3 Mature IOS	429	24.9	79.6

Comparing these annual electricity requirements to the potential on-site renewable electricity is the first step to understanding the potential for meeting the electricity requirements, but understanding how the renewable electricity is produced and consumed temporally (i.e., hour-by-hour in these analyses) is the second step. Renewable production profiles for the 8760 hours in the year were simulated and then a resource dispatch analysis was conducted to understand how much of that renewable energy could be used by the electrolysis system and how much energy storage may be needed.

4.1. Solar

Based on the initial site layouts provided by Valley Link (Figure 12 below), there is approximately 47 acres of land available for building solar PV. It was assumed that PV could be built in the stormwater retention area on appropriately designed racking, shown in the northeast corner of the site.

[27] "IOS" is Initial Operating Segment between Dublin/Pleasanton BART Station and Mountain House

Approximation	Acres/MWac	Acres – Valley Link	MWac Potential
SEIA - Aggressive[28]	5	47	9
SEIA - Conservative[28]	10	47	5
NREL Study Single Axis Tracking[29]	6	47	8
NREL Study Fixed[29]	5	47	9
Plant Predict Max Capacity[30]	4	47	12
PV EPC Firm estimate (Assume >95% of the land area is buildable)	4	47	12

Table 4: Different approximations for acres/MWac of solar photovoltaic capacity

Table 4 summarizes different Acres/MWac metrics collected and/or used by different entities. The metric depends heavily on the portion of land that is cost-effectively buildable, i.e., hilly terrain may not be buildable or cost-effective to build on, therefore the acres/MWac metric has a large variation.

Assuming that the land available at the Tracy OMF is flat and using the available metrics, the solar capacity that could be installed is 8-12 MWac. This does not include space available on rooftops and parking lots/structures.

Based on this capacity estimate and a simulation in Plant Predict (solar PV software), the production from a facility located in Tracy would be ~17.5 GWh/yr to 26.3 GWh/yr. Based upon the electricity requirements in Table 3, Phase 1 may potentially be supplied by the on-site solar but the later phases electricity requirements exceed what is possible on that 47 acres. Focusing on Phase 1, a 1 tonne/day electrolyzer would be required to meet the demand. The electrolyzer can only use 2.6 MWac of the PV MWac being produced at peak times (i.e., up to 12 MWac). Therefore, the excess would need to be stored in a battery (or other energy storage technology) and shifted to nighttime operation (see Figure 14). Even in Phase 1, there would also be seasonal issues where there might not be enough solar production, particularly in the winter.

28 https://www.seia.org/initiatives/siting-permitting-land-use-utility-scale-solar#:~:text=Research%20from%20the%20National%20Renewable,(MW)%20of%20generating%20capacity
29 https://www.nrel.gov/docs/fy13osti/56290.pdf
30 PV Modeling software. https://plantpredict.com/

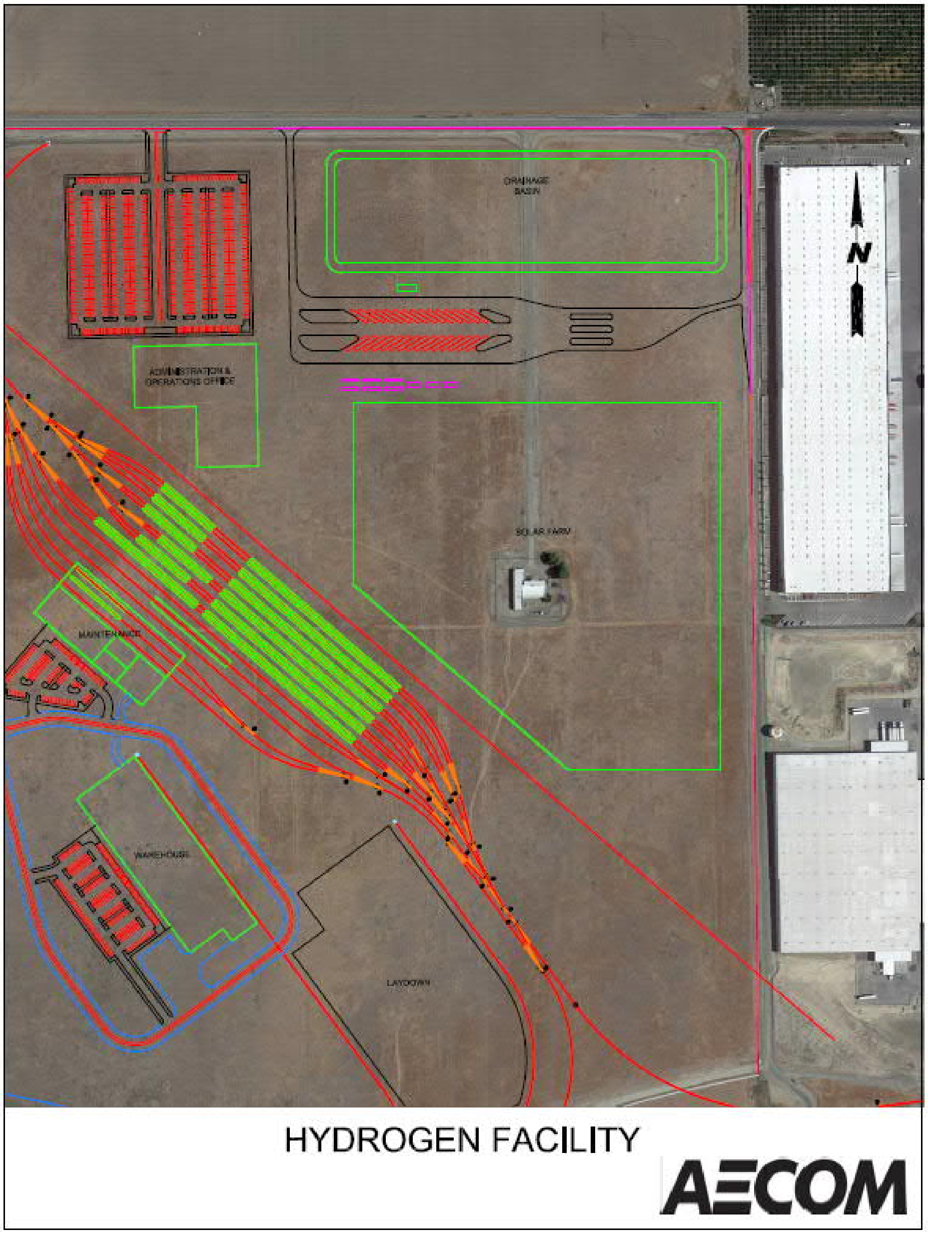
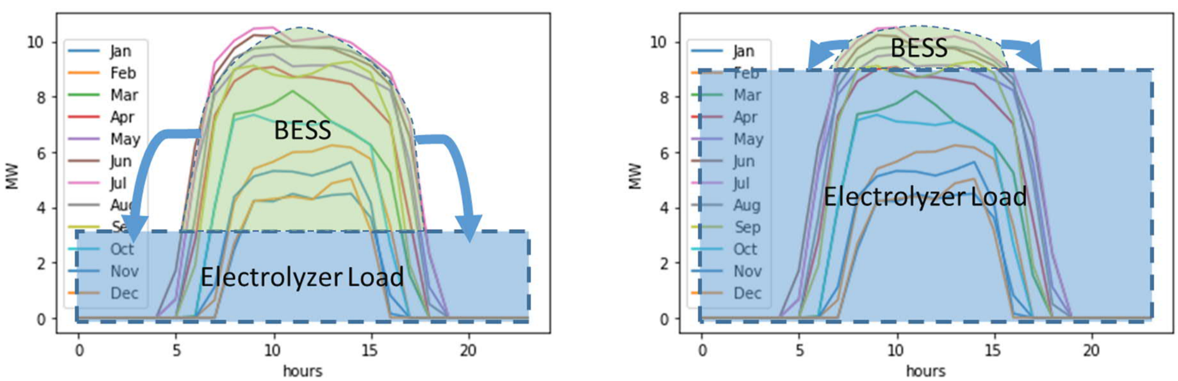


Figure 12: Initial site layout

Figure 13: Screenshot of PV system layout from Plant Predict software



a) b)

Figure 14: Schematic for electrolyzer load and energy storage shifting of PV electricity to serve electrolyzer load during the different months of the year for a) Phase 1 and b) Phase 2 (PV generation profiles are monthly averages for 1-year simulation in Tracy, California)

To understand the cost of electricity from the PV plant, the simple levelized cost of electricity (LCOE)[31] was calculated based on the information in Figure 15 and using a typical yearly OpEx estimate of 2% of CapEx. This results in a simple LCOE of $43/MWh for a 12 MWac PV plant. The LCOE can be used as a rough metric for what the price of the electricity might be. However, this LCOE is for a PV only facility and there will need to be energy storage to shift excess energy in the day to the nighttime (unless a connection to the grid is made, see Section 4.4).

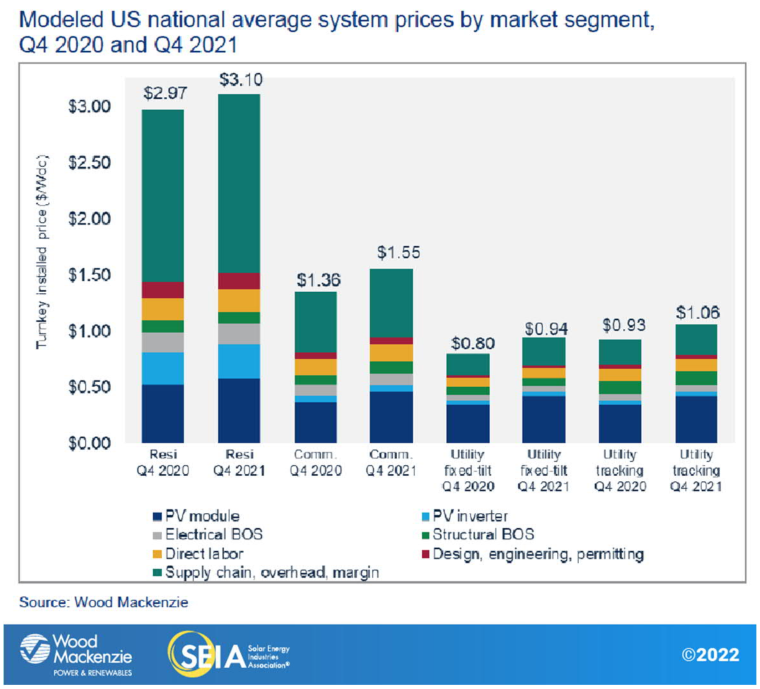


Figure 15: Solar PV CapEx data for different system types[32]

4.1.1. Energy Storage

Given that energy storage will be needed to shift excess daytime PV energy to the night, a sensitivity analysis was conducted to understand the impact energy storage would have on increasing the utilization of the electrolyzer and the impact on the simple LCOE. This sensitivity analysis will be described in this section and focused on varying the power level of the energy storage and duration of the energy storage. These two specifications combine to provide the energy storage overall but their ratio with respect to the electrolyzer power level, PV power level, and the number of hours of sunlight each day are important to understanding the effect on electrolyzer utilization and simple LCOE.

There is a portfolio of different energy storage technologies, and a down-selection of energy storage technology was required. Figure 16 shows the deployment levels of the different energy storage technologies and shows the dominance of Li-ion. Figure 17 shows the installed costs for different energy storage technologies with Li-ion being the lowest cost solution at the scale of this project (~10MW range).

[31] https://www.nrel.gov/analysis/tech-lcoe-documentation.html
[32] https://www.seia.org/research-resources/solar-market-insight-report-2021-year-review

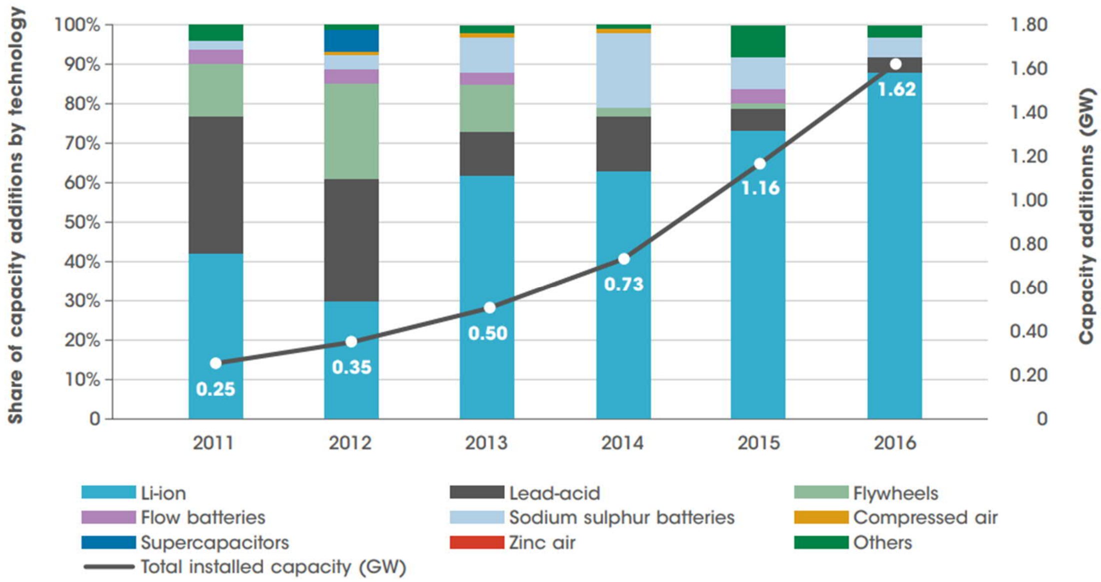


Figure 16: Energy storage system deployments by technology type[33]

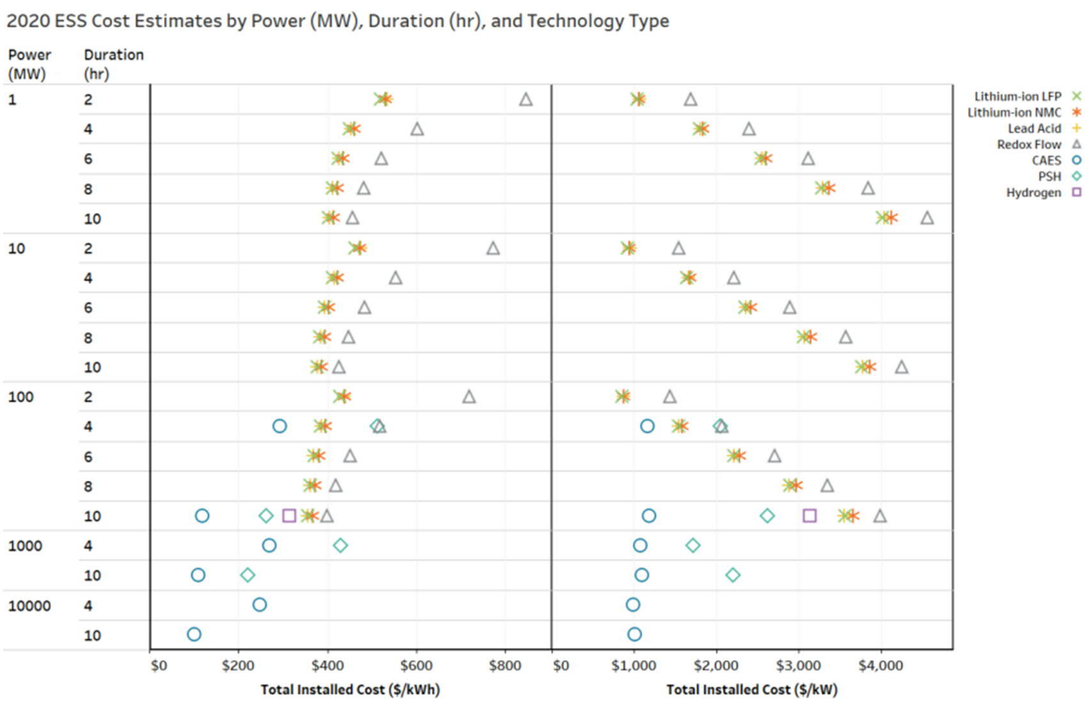


Figure 17: Variation in installed cost per unit capacity for Li-ion and flow battery technologies[34]

The other key parameters in a high-level BESS analysis are the round-trip efficiency (RTE) and OpEx as a % of CapEx including warranty and capacity augmentation (Li-ion systems degrade and must be augmented to maintain the original capacity). The OpEx when including these items is estimated at

[33] https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2019/Sep/IRENA_Utility-scale-batteries_2019.pdf
[34] https://www.pnnl.gov/sites/default/files/media/file/Final%20-%20ESGC%20Cost%20Performance%20Report%2012-11-2020.pdf

4% of CapEx. The RTE can be 95% at the DC terminals of the battery, but accounting for the additional losses from the inverter, cables, and transformers, the typical RTE is 85% - 89% depending on the specific architecture of the system. For this study, a RTE of 88% was used.

To properly develop the financial model, the potential electrolyzer utilization for a given combination of PV and BESS must be understood for each of the phases. In order to analyze this, the 8760 hour simulation from Plant Predict was used in combination with a simple dispatch model for an electrolyzer and BESS. This dispatch model utilized the following logic in each hour of the year:

1) Any PV available up to max electrolyzer power is used by electrolyzer
2) Any excess PV after that dispatch is used to charge BESS until 100% state of charge (SOC)
3) Any excess PV after that dispatch is sent to grid
4) If max electrolyzer power not reached with only PV power then BESS will dispatch energy to electrolyzer (if max electrolyzer power not reached and BESS SOC > 0%)

The dispatch model was run for various scenarios of BESS power and durations to understand the effect on electrolyzer utilization by increasing the BESS power/duration as well as understand how much excess PV energy might still be available.

Table 5 through Table 7 show the variation of the electrolyzer utilization for different sizes of BESS for the 12 MWac PV potential at the Tracy OMF site in the three project phases. These tables are used in the financial model to set different parameters that are important for analyzing the project such as electrolyzer utilization and excess PV energy available. These tables show several different variables: the mean daily hydrogen production when using only the PV+BESS electricity, the simple LCOE from the PV+BESS system, the electrolyzer utilization, the excess PV energy available after serving the electrolyzer load, the simple levelized cost of hydrogen (LCOH) when using only the PV+BESS system electricity, and the simple LCOH when also using grid purchases to ensure 24/7/365 hydrogen production.

The first takeaway from these tables is that the electrolyzer utilization can be increased by using the BESS to shift PV energy, however, as more BESS capacity is installed the LCOE goes up because the BESS doesn't provide more electricity generation for the denominator of the LCOE calculation but rather only increases the numerator. The combination of electrolyzer utilization increase and LCOE increase need to be understood in relation to the LCOH in order to identify which scenario will be the lowest cost. If only using PV+BESS electricity, the lowest LCOH is achieved by using only PV with no BESS. However, this does not provide hydrogen 24/7/365 as shown by the mean daily production which is much lower than the design of 1 tonne/day. Even with very large BESS, the mean daily production is only 700 kg/d versus the designed capacity of 1 tonne/day. Therefore, grid purchases are required. The LCOH with grid purchases variable shows the cost when purchasing any remaining electricity needed to run the electrolyzer at full capacity from the grid at an average price of $130.4/MWh.[35] Using this metric to guide the best BESS selection for Phase 1, a BESS with the same power as the electrolyzer with a 4-8 hour duration would provide the lowest LCOH. When the project moves to Phase 2, the BESS system from phase 1 is not sufficient to power the electrolyzer because there is not enough excess PV energy to shift throughout the day to meet the constant large demand

[35] https://www.eia.gov/electricity/state/california/

from the electrolyzer. This also occurs in Phase 3.

Table 8 through Table 10 show the same analysis structure as in Table 5 through Table 7 but with a larger PV installation (48 MWac) assuming additional land could be utilized at the Tracy OMF by either acquiring more land or moving the OMF to another site and using the full 200 acres available. The key takeaway from these tables is that the larger the ratio of the PV power to the electrolyzer power the better the LCOH. As the capacity of the electrolyzer increases in the different phases, the cost optimal BESS shifts as well.

A very important point to be made here is that as the grid electricity price changes, these results will also change. Therefore, the financial model was enabled such that as the grid electricity price changes so will the selection of the cost optimal BESS, so as to select the proper BESS size, electrolyzer utilization, and excess PV available for sale back to the grid.

Table 5: Phase 1 8760-hr electrolyzer dispatch from PV+BESS electricity supply results for sensitivity analysis for different BESS power and duration levels based on 47 acres of available land for PV

		50 acres / Phase 1: PV P=12 MW; ELY P = 2.4 MW																																			
		Mean Daily H2 Production (tpd)						sLCOE from PV+BESS ($/MWh)						Electrolyzer Utilization						Excess PV						sLCOH using only PV+BESS ($/kg)						LCOH w/ Grid Purchases [$/kg-H2]					
	Hours:	2	4	6	8	10	12	2	4	6	8	10	12	2	4	6	8	10	12	2	4	6	8	10	12	2	4	6	8	10	12	2	4	6	8	10	12
BESS	0	0.4	0.4	0.4	0.4	0.4	0.4	77	77	77	77	77	77	43%	43%	43%	43%	43%	43%	67%	67%	67%	67%	67%	67%	8.3	8.3	8.3	8.3	8.3	8.3	11.3	11.3	11.3	11.3	11.3	11.3
Power	0.25x ELY P	0.4	0.4	0.4	0.4	0.4	0.4	80	82	84	86	88	89	44%	44%	47%	48%	50%	51%	67%	66%	63%	63%	61%	61%	8.4	8.5	8.4	8.5	8.5	8.6	11.4	11.4	11.1	11.1	11.0	11.1
[MW]:	0.5x ELY P	0.4	0.4	0.4	0.5	0.5	0.5	82	86	90	94	98	102	45%	48%	52%	55%	58%	60%	66%	63%	60%	57%	55%	53%	8.5	8.5	8.6	8.7	8.9	9.1	11.4	11.2	11.0	10.9	10.9	11.0
	1x ELY P	0.4	0.5	0.5	0.6	0.6	0.6	88	95	103	111	119	127	50%	58%	64%	70%	74%	76%	61%	55%	49%	45%	41%	40%	8.5	8.7	9.1	9.4	9.9	10.4	11.0	10.7	10.7	10.7	11.0	11.4
	2x ELY P	0.5	0.6	0.7	0.7	0.7	0.7	98	114	130	145	160	176	58%	72%	83%	86%	86%	87%	54%	43%	34%	32%	31%	31%	8.9	9.6	10.4	11.4	12.5	13.5	10.9	10.8	11.1	12.0	13.0	14.0

Table 6: Phase 2 8760-hr electrolyzer dispatch from PV+BESS electricity supply results for sensitivity analysis for different BESS power and duration levels based on 47 acres of available land for PV

		50 acres / Phase 2: PV P=12 MW; ELY P = 9.4 MW																																			
		Mean Daily H2 Production (tpd)						sLCOE from PV+BESS ($/MWh)						Electrolyzer Utilization						Excess PV						sLCOH using only PV+BESS ($/kg)						LCOH w/ Grid Purchases [$/kg-H2]					
	Hours:	2	4	6	8	10	12	2	4	6	8	10	12	2	4	6	8	10	12	2	4	6	8	10	12	2	4	6	8	10	12	2	4	6	8	10	12
BESS	0	1.0	1.0	1.0	1.0	1.0	1.0	77	77	77	77	77	77	32%	32%	32%	32%	32%	32%	5%	5%	5%	5%	5%	5%	9.3	9.3	9.3	9.3	9.3	9.3	13.3	13.3	13.3	13.3	13.3	13.3
Power	0.25x ELY P	1.1	1.1	1.1	1.1	1.1	1.1	87	94	102	109	116	124	32%	33%	33%	33%	33%	33%	2%	1%	0%	0%	0%	0%	9.9	10.3	10.8	11.3	11.8	12.3	13.9	14.3	14.7	15.2	15.7	16.2
[MW]:	0.5x ELY P	1.1	1.1	1.1	1.1	1.1	1.1	97	111	126	141	155	170	33%	33%	33%	33%	33%	33%	1%	0%	0%	0%	0%	0%	10.5	11.5	12.5	13.5	14.5	15.5	14.4	15.4	16.4	17.4	18.4	19.4
	1x ELY P	1.1	1.1	1.1	1.1	1.1	1.1	116	145	174	204	233	262	33%	33%	33%	33%	33%	33%	0%	0%	0%	0%	0%	0%	11.8	13.8	15.8	17.8	19.8	21.8	15.7	17.7	19.7	21.7	23.7	25.7
	2x ELY P	1.1	1.1	1.1	1.1	1.1	1.1	154	213	271	330	388	447	33%	33%	33%	33%	33%	33%	0%	0%	0%	0%	0%	0%	14.4	18.4	22.4	26.4	30.4	34.5	18.3	22.3	26.3	30.3	34.3	38.4

Table 7: Phase 3 8760-hr electrolyzer dispatch from PV+BESS electricity supply results for sensitivity analysis for different BESS power and duration levels based on 47 acres of available land for PV

		50 acres / Phase 3: PV P=12 MW; ELY P = 13.5 MW																																			
		Mean Daily H2 Production (tpd)						sLCOE from PV+BESS ($/MWh)						Electrolyzer Utilization						Excess PV						sLCOH using only PV+BESS ($/kg)						LCOH w/ Grid Purchases [$/kg-H2]					
	Hours:	2	4	6	8	10	12	2	4	6	8	10	12	2	4	6	8	10	12	2	4	6	8	10	12	2	4	6	8	10	12	2	4	6	8	10	12
BESS	0	1.1	1.1	1.1	1.1	1.1	1.1	77	77	77	77	77	77	23%	23%	23%	23%	23%	23%	0%	0%	0%	0%	0%	0%	10.8	10.8	10.8	10.8	10.8	10.8	15.7	15.7	15.7	15.7	15.7	15.7
Power	0.25x ELY P	1.1	1.1	1.1	1.1	1.1	1.1	91	101	112	122	133	143	23%	23%	23%	23%	23%	23%	0%	0%	0%	0%	0%	0%	11.7	12.4	13.2	13.9	14.6	15.3	16.6	17.4	18.1	18.8	19.5	20.2
[MW]:	0.5x ELY P	1.1	1.1	1.1	1.1	1.1	1.1	105	126	147	168	188	210	23%	23%	23%	23%	23%	23%	0%	0%	0%	0%	0%	0%	12.7	14.1	15.5	17.0	18.4	19.8	17.6	19.0	20.5	21.9	23.3	24.8
	1x ELY P	1.1	1.1	1.1	1.1	1.1	1.1	132	174	216	258	300	342	23%	23%	23%	23%	23%	23%	0%	0%	0%	0%	0%	0%	14.5	17.4	20.3	23.2	26.0	28.9	19.5	22.3	25.2	28.1	30.9	33.8
	2x ELY P	1.1	1.1	1.1	1.1	1.1	1.1	187	271	355	439	522	606	23%	23%	23%	23%	23%	23%	0%	0%	0%	0%	0%	0%	18.3	24.0	29.8	35.5	41.2	47.0	23.2	29.0	34.7	40.5	46.2	52.0

Table 8: Phase 1 8760-hr electrolyzer dispatch from PV+BESS electricity supply results for sensitivity analysis for different BESS power and duration levels based on 200 acres of available land for PV

		200 acres / Phase 1: PV P=48 MW; ELY P = 2.4 MW																																			
		Mean Daily H2 Production (tpd)						sLCOE from PV+BESS ($/MWh)						Electrolyzer Utilization						Excess PV						sLCOH using only PV+BESS ($/kg)						LCOH w/ Grid Purchases [$/kg-H2]					
	Hours:	2	4	6	8	10	12	2	4	6	8	10	12	2	4	6	8	10	12	2	4	6	8	10	12	2	4	6	8	10	12	2	4	6	8	10	12
BESS	0	0.4	0.4	0.4	0.4	0.4	0.4	77	77	77	77	77	77	45%	45%	45%	45%	45%	45%	91%	91%	91%	91%	91%	91%	8.1	8.1	8.1	8.1	8.1	8.1	10.9	10.9	10.9	10.9	10.9	10.9
Power	0.25x ELY P	0.4	0.4	0.4	0.4	0.4	0.5	78	78	79	79	80	80	45%	46%	49%	50%	53%	54%	91%	91%	90%	90%	90%	90%	8.1	8.1	8.0	8.0	7.9	7.9	11.0	10.9	10.5	10.5	10.1	10.1
[MW]:	0.5x ELY P	0.4	0.4	0.5	0.5	0.5	0.5	79	80	80	81	82	83	46%	50%	54%	58%	62%	64%	91%	90%	90%	89%	88%	87%	8.1	8.0	7.9	7.8	7.7	7.7	10.9	10.5	10.1	9.7	9.5	9.3
	1x ELY P	0.4	0.5	0.6	0.6	0.7	0.7	80	82	84	86	88	90	53%	61%	68%	75%	81%	84%	90%	88%	87%	85%	84%	83%	7.9	7.7	7.6	7.6	7.6	7.7	10.2	9.5	9.0	8.6	8.4	8.3
	2x ELY P	0.5	0.6	0.8	0.8	0.8	0.8	82	86	90	94	98	102	60%	76%	90%	96%	97%	97%	88%	85%	82%	81%	81%	81%	7.8	7.6	7.6	7.8	8.0	8.3	9.6	8.6	8.0	7.9	8.1	8.4

Table 9: Phase 2 8760-hr electrolyzer dispatch from PV+BESS electricity supply results for sensitivity analysis for different BESS power and duration levels based on 200 acres of available land for PV

		200 acres / Phase 2: PV P=48 MW; ELY P = 9.4 MW																																			
		Mean Daily H2 Production (tpd)						sLCOE from PV+BESS ($/MWh)						Electrolyzer Utilization						Excess PV						sLCOH using only PV+BESS ($/kg)						LCOH w/ Grid Purchases [$/kg-H2]					
	Hours:	2	4	6	8	10	12	2	4	6	8	10	12	2	4	6	8	10	12	2	4	6	8	10	12	2	4	6	8	10	12	2	4	6	8	10	12
BESS	0	1.4	1.4	1.4	1.4	1.4	1.4	77	77	77	77	77	77	43%	43%	43%	43%	43%	43%	68%	68%	68%	68%	68%	68%	8.3	8.3	8.3	8.3	8.3	8.3	11.3	11.3	11.3	11.3	11.3	11.3
Power	0.25x ELY P	1.4	1.5	1.6	1.6	1.7	1.7	80	82	84	85	87	89	44%	44%	47%	48%	50%	51%	67%	67%	64%	64%	62%	61%	8.4	8.5	8.4	8.5	8.5	8.6	11.3	11.3	11.1	11.1	11.0	11.0
[MW]:	0.5x ELY P	1.5	1.6	1.7	1.8	1.9	2.0	82	86	90	94	97	101	45%	48%	52%	56%	58%	60%	66%	63%	60%	58%	55%	54%	8.5	8.5	8.6	8.7	8.9	9.1	11.4	11.1	11.0	10.8	10.8	10.9
	1x ELY P	1.7	1.9	2.1	2.3	2.5	2.5	87	95	103	110	118	126	50%	58%	64%	70%	75%	76%	62%	56%	50%	46%	42%	41%	8.5	8.7	9.0	9.4	9.8	10.3	11.0	10.7	10.6	10.7	10.9	11.3
	2x ELY P	1.9	2.4	2.7	2.8	2.9	2.9	97	113	129	144	159	174	58%	72%	83%	86%	87%	87%	55%	44%	35%	33%	32%	32%	8.9	9.5	10.3	11.3	12.3	13.4	10.9	10.7	11.0	11.9	12.9	13.9

Table 10: Phase 3 8760-hr electrolyzer dispatch from PV+BESS electricity supply results for sensitivity analysis for different BESS power and duration levels based on 200 acres of available land for PV

		200 acres / Phase 3: PV P=48 MW; ELY P = 13.5 MW																																			
		Mean Daily H2 Production (tpd)						sLCOE from PV+BESS ($/MWh)						Electrolyzer Utilization						Excess PV						sLCOH using only PV+BESS ($/kg)						LCOH w/ Grid Purchases [$/kg-H2]					
	Hours:	2	4	6	8	10	12	2	4	6	8	10	12	2	4	6	8	10	12	2	4	6	8	10	12	2	4	6	8	10	12	2	4	6	8	10	12
BESS	0	2.0	2.0	2.0	2.0	2.0	2.0	77	77	77	77	77	77	41%	41%	41%	41%	41%	41%	55%	55%	55%	55%	55%	55%	8.4	8.4	8.4	8.4	8.4	8.4	11.5	11.5	11.5	11.5	11.5	11.5
Power	0.25x ELY P	2.0	2.1	2.2	2.2	2.3	2.3	81	83	86	89	92	94	42%	43%	46%	47%	49%	49%	54%	53%	50%	49%	47%	46%	8.5	8.7	8.7	8.8	8.9	9.1	11.6	11.6	11.5	11.5	11.5	11.6
[MW]:	0.5x ELY P	2.1	2.2	2.4	2.5	2.6	2.7	84	90	95	101	106	112	44%	47%	51%	54%	56%	57%	53%	48%	45%	41%	39%	37%	8.7	8.8	9.0	9.3	9.6	9.9	11.7	11.5	11.5	11.6	11.7	11.9
	1x ELY P	2.3	2.6	2.9	3.1	3.3	3.3	92	103	114	125	136	147	49%	55%	61%	66%	70%	71%	47%	39%	32%	27%	23%	22%	8.9	9.3	9.9	10.5	11.1	11.9	11.5	11.5	11.7	12.0	12.5	13.2
	2x ELY P	2.6	3.2	3.6	3.6	3.7	3.7	106	129	151	173	194	216	56%	67%	75%	77%	77%	78%	38%	25%	16%	14%	14%	13%	9.6	10.7	12.0	13.5	14.9	16.4	11.7	12.2	13.1	14.5	15.9	17.3

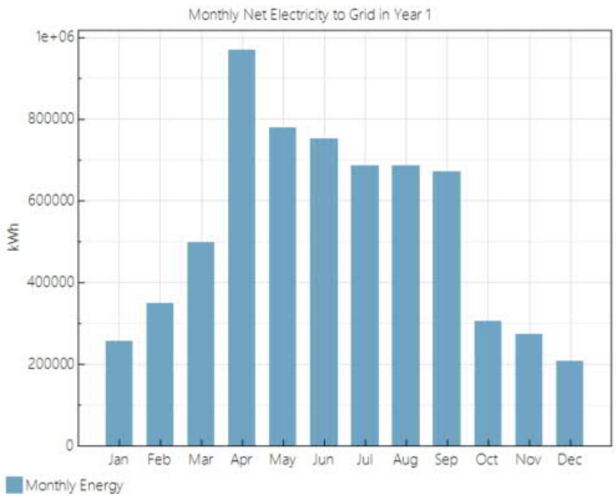
4.2. Wind

Compared to solar, industrial scale wind farms require significantly more land, depending on the wind potential in the region and size of turbines. For large scale industrial facilities, the total land required is highly variable. An NREL study collecting data from 172 wind projects producing a minimum of 20 MW across the US found that the total land required for wind ranged from 30 acres/MW to 140 acres/MW with the average at 85 acres/MW.[36] For the Valley Link wind capacity estimate, it was assumed that there is 100 acres of land available for building wind turbines. Using the NREL large industrial wind farmland availability data, the Tracy facility could generate anywhere from 0.7 MW to 3.3 MW of wind energy. Based on this estimate, the Tracy facility does not have enough land for industrial scale wind farming. Small scale wind farms, consisting of only a few wind turbines, can be placed on much smaller pieces of land, and there is no rule of thumb other than turbine spacing. For example, the Safeway in Tracy has a 2 MW wind farm (2 x 1 MW turbines), on a piece of land that is only 7.5 acres large (see figure to the right), with only ~100m spacing between the two turbines. The capacity factor for these turbines is 13.9% based on the eGRID database[37].

Figure 18: Bird's eye view of Safeway distribution centre wind turbines in Tracy

Using the System Advisory Model (SAM) from NREL, and selecting the Tracy wind generation profile, an estimate for the wind energy capacity was developed. To maximize the wind turbine output, the team chose a 5 MW wind farm capacity using 2 GE 2.5 MW turbines. From the SAM model simulation, a 5 MW wind farm located in Tracy would produce ~6.4 GWh/year. The SAM model also provided a wind farm layout with a spacing of 800m between the two turbines. There is sufficient space at the Tracy facility for these two turbines, however detailed analysis and engineering will be required to determine where they could be built. The SAM also provided analysis of the project costs and estimated LCOE. The project cost and LCOE were significantly higher than the solar PV, so wind was not assumed as an on-site renewable energy provider in this feasibility study. It is possible that significant CapEx cost reductions could be achieved since the SAM is likely using older data, but that would require further investigation and given the gap between solar PV and wind LCOE, it was decided to limit the study to solar PV.

36 https://www.nrel.gov/docs/fy09osti/45834.pdf
37 https://www.epa.gov/egrid



Metric	Value
Net electricity to grid (year 1)	6,425,776 kWh
Capacity	5,000 kW
Capacity factor (year 1)	14.7%
Levelized COE (nominal)	15.37 ¢/kWh
Levelized COE (real)	12.21 ¢/kWh
Electricity bill without system (year 1)	$147,505
Electricity bill with system (year 1)	$60,360
Net savings with system (year 1)	$87,145
Net present value	$-8,887,306
Simple payback period	NaN
Discounted payback period	NaN
Net capital cost	$37,000,000
Equity	$7,400,000
Debt	$29,600,000

Figure 19: Wind modeling results from the System Advisor Model from NREL[38]

4.3. Grid Electricity

Due to the variability of the on-site renewable energy and the requirement of Valley Link to operate 24 hours a day, 7 days a week, and 365 days per year, a grid connection will be required.

There are different voltage levels on the electricity grid and can be roughly categorized as Transmission (100+ kV) and Distribution (0.48 – 66 kV). To make a broad generalization, connecting at higher voltages requires more expensive equipment but can allow lower cost electricity and better access to electricity markets.

The Investor-Owned Utilities in California were required to perform analysis on the capacity of their distribution systems to host Distributed Energy Resources (broad term for devices like rooftop solar, batteries, fuel cells, etc. that connect to the grid at the distribution level).

The map for PG&E’s analysis for those circuits in the vicinity of the Tracy OMF is shown in Figure 20. The most important item to note is that there is no available capacity for new load on the existing Lammers 12kV circuit. There are high voltage transmission and substations nearby so there is potential to interconnect to HV transmission, which may be of value to renewable developers that may own/operate the solar PV + BESS energy farm. Connecting to the higher voltage circuits can be a multi-year process and must begin immediately based on the desired operation dates assumed in these project phases.

[38] https://sam.nrel.gov/

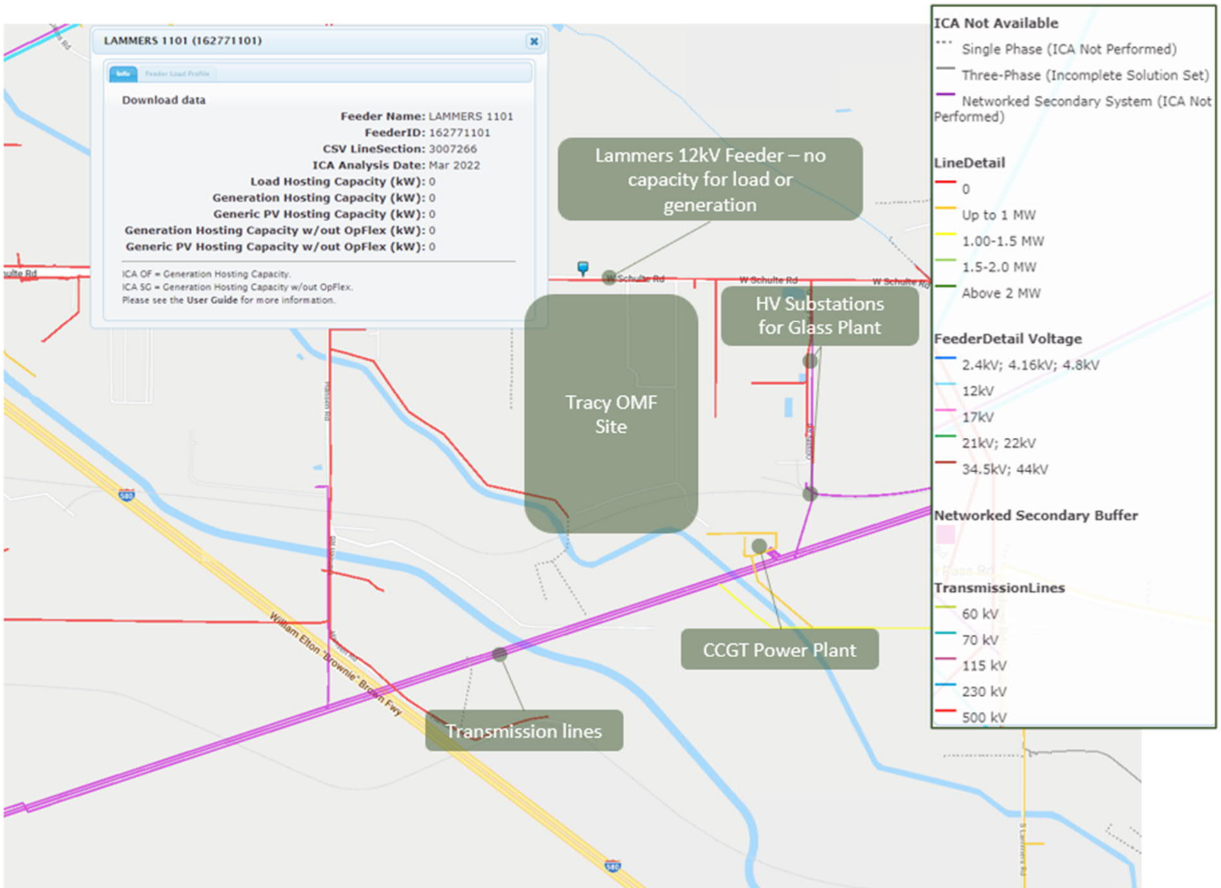


Figure 20: PG&E's analysis of available circuit capacity for Distributed Energy Resources in the vicinity of Tracy OMF (the PG&E Integration Capacity Analysis [ICA] Map) [39]

[39] https://www.pge.com/en_US/for-our-business-partners/distribution-resource-planning/distribution-resource-planning-data-portal.page?ctx=large-business

5. ELECTROLYSIS PRODUCTION FACILITY

As outlined in Section 2, the hydrogen production pathway that best meets the criteria for the Valley Link project is water electrolysis. Electrolyzers range in size from small appliance-size to large-scale that could be connected directly to renewable electricity generation sources. Alkaline electrolyzers are the oldest and most mature technology and have been used in industrial settings for over 100 years. Recent interest in hydrogen as an energy carrier and transportation fuel has accelerated the electrolyzer technology development, subsequently improving cost and efficiency. The electrolysis process uses electricity to split water molecules into hydrogen (H_2) and oxygen (O_2).

The overall reaction is: 2 H2O(l) → 2 H2(g) + O2(g), and a proton exchange membrane electrolysis process is schematically illustrated in Figure 21.

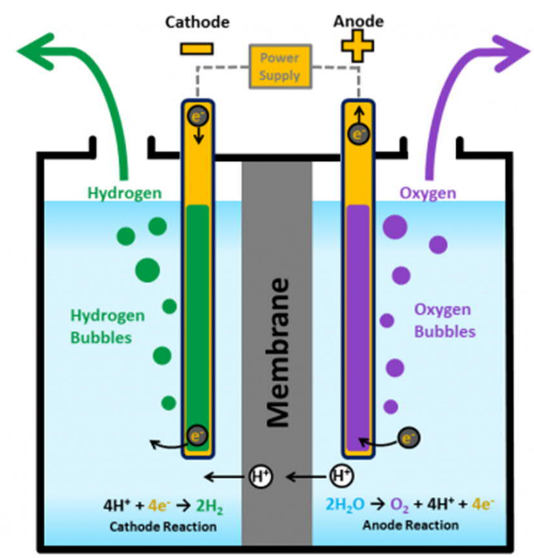


Figure 21: Water Electrolysis Reaction Overview

There are three primary types of electrolysis technologies: proton exchange membrane (PEM), alkaline (AEL), and solid oxide electrolyzers (SOEC). Solid Oxide Electrolysis Cell (SOEC) has seen development in recent years but is not yet commercial. SOEC technology is still at the demonstration stage but offers high energy efficiency potential when coupled with suitably high temperatures from heat sources, e.g. nuclear plants or industrial heat. SOEC must operate at 600-1000℃ compared to PEM electrolyzers, which typically operate between 20-90℃ and commercial AEL operate between 40-90℃.PEM electrolyzers have become more common in recent years due to breakthroughs in membrane cell density and because they are capable of high turndown ratios and fast ramping response times, allowing the system to be used for electrical load following operations and easily integrating with intermittent power generation systems, e.g., solar PV. Alkaline electrolyzers are a mature technology and historically the technology of choice for commercial scale plants, but require a more consistent power supply to operate efficiently, and they lack the flexibility of a PEM electrolyzer's high turndown ratio and fast response times. The PEM electrolyzer systems are capable of producing hydrogen which meets the SAE J2719 quality specification required for fueling of hydrogen vehicles. Depending on the PEM system purchased, the outlet pressure varies from 10-40 bar.

PEM is the ideal technology for this application due to:

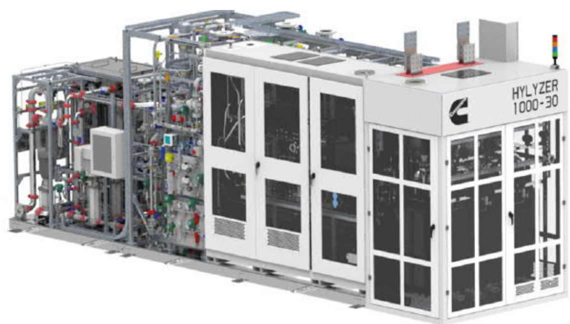
- Fast startup time (<1 minute)
- Fast process dynamics (~5%/second ramp rate)
- High turndown ratio (~15-100%)
- Smaller modular sizes, enabling phased deployment and gradual scaling up of production facility
- Higher production pressure, saving electrical costs for compression

PEM electrolyzer systems are commercially available in both indoor and outdoor (containerized) configurations as shown in Figure 22 and Figure 23. The outdoor units are constructed within modular 20' and 40' standard shipping containers, which allows for ease of installation and transportation. The examples shown in Figure 22 are 1,000 kg/d systems, which represents the largest containerized systems currently available on the market. These systems are comprised of one 40' container which houses the process equipment such as the electrolyzer stacks, water treatment, and hydrogen dryer, and another 40' container which houses the electrical equipment such as rectifier, transformer, and controllers. As shown in Table 11, the containerized systems include all of the required balance of plant equipment, whereas the indoor units allow the project owner to centralize the ancillary systems across multiple electrolyzer units.

While the containerized systems allow for simple installation, minimal site preparation, and doesn't require an enclosure, there are potential benefits to consider for indoor systems once the production facility reaches scales larger than ~4,000 kg/d. These include:

- Cost savings through centralized ancillary systems such as water treatment, instrument air, chillers, and cooling water
- Significantly decreased footprint
- Decreased maintenance costs
- Siting within secure and climate-controlled building which protects equipment from severe weather

Figure 22: Containerized 1 TPD Electrolyzer Systems from Cummins (left) and NEL (right)



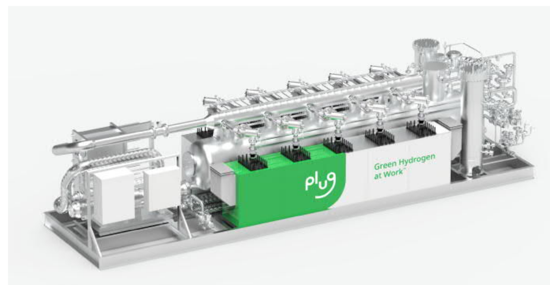


Figure 23: Indoor Electrolyzer Systems

Table 11: Balance of Plant Systems for Outdoor vs. Indoor PEM Systems

Balance of Plant Option	Outdoor PEM Systems	Indoor PEM Systems
Gas Cooling Chiller	Included	Optional
Electrolysis Cooling with Dry Cooler	Included	Optional
Water Purification System	Included	Optional
Instrument Air Compressor	Included	Optional
Hydrogen Purification System	Included	Included
MV Transformer & Rectifier	Included	Included

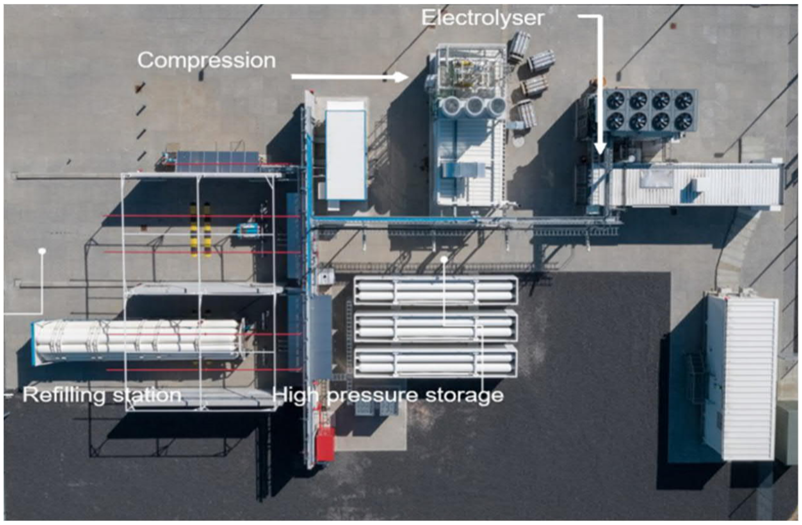


Figure 24: 500 kg/d Containerized system with Compression, Storage, and Trailer Refueling

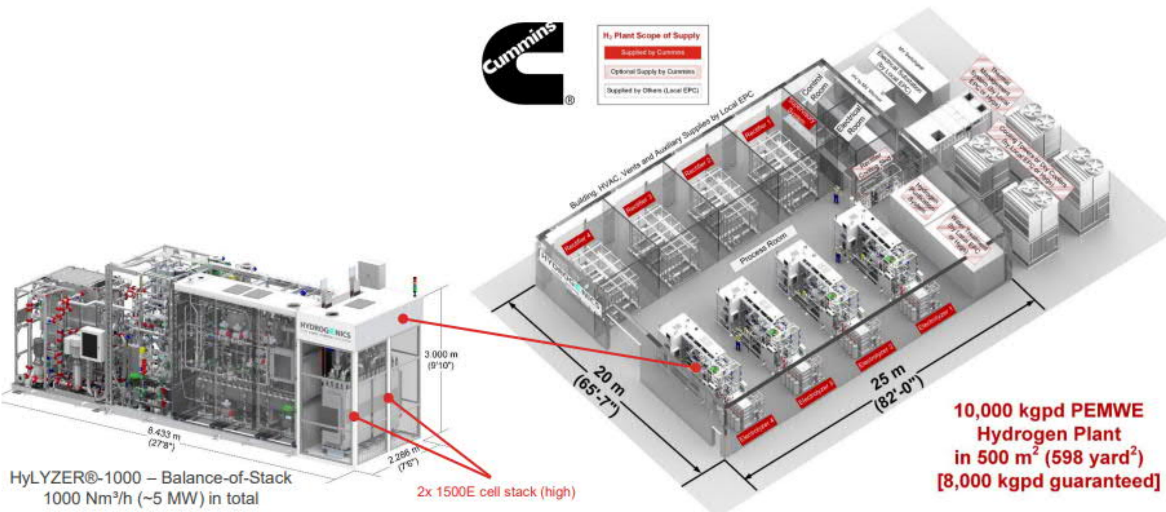


Figure 25: 8,000 kg/d Indoor System from Cummins

5.1. Block Flow Diagram

Figure 26 shows the block flow diagram for the hydrogen production facility feasibility study. There are several main elements to the block diagram:

1. Electrolyzer process section (water treatment stacks, dryer, H2 mgmt. system, O2 mgmt. system)
2. Electrolyzer power supply section (rectifiers, controllers)
3. Compression, storage, and dispensing
4. LH2 backup storage
5. Hydrogen supply to Valley Lick, on-site hydrogen FCEB fueling, and offsite demand from local bus transit operators

The block flow diagram shows the final Phase 3 scale of the production facility, which is projected to be completed and installed in 2030. The diagram illustrates a production facility made up of five 1,000 kg/d containerized PEM systems, although indoor systems may also be used for the design.

The electricity inputs are a combination of onsite renewable generated electricity and grid electricity. This electricity will be transformed at the system substation to a voltage acceptable for input to the electrolyzer's AC/DC rectifier (5-30 kV). Once the electricity is rectified to DC, this electricity is fed to the electrolyzer stacks to split the water into hydrogen and oxygen. The low voltage transformer is required to supply equipment such as the gaseous hydrogen compressors, dispensers, and process instrumentation with 480 V power.

The water input to the system will require treatment to protect the electrolyzer stack from fouling from biological and chemical contaminants. Typically, containerized PEM electrolyzers include a reverse osmosis and resin de-ionizer system, designed to treat potable water from a city water connection to the required specifications. Depending on the composition of water available on site, an additional water pre-treatment system may be required.

Chilling will be required for various components across the system and could be provided by a central chilling plant or separate chillers for each component that requires it (or a mix of both). This will depend upon the specific system architecture and environmental factors.

After water is electrolyzed to produce H2 and O2, the O2 is vented and the H2 must be first dried before entering the compression stage of the system. The compression system is designed to have two stages of compression with low pressure (500 bar) storage and high pressure (900 bar) storage after each compression stage. The dispensing will consist of two dispensers and one area for fueling the mobile storage systems for supplying H2 to local bus transit operators. One dispenser will be for fueling buses and other vehicles requiring 350 bar hydrogen. The other set of dispensers will include 8 dispensers for refueling the Valley Link trains at 700 bar.

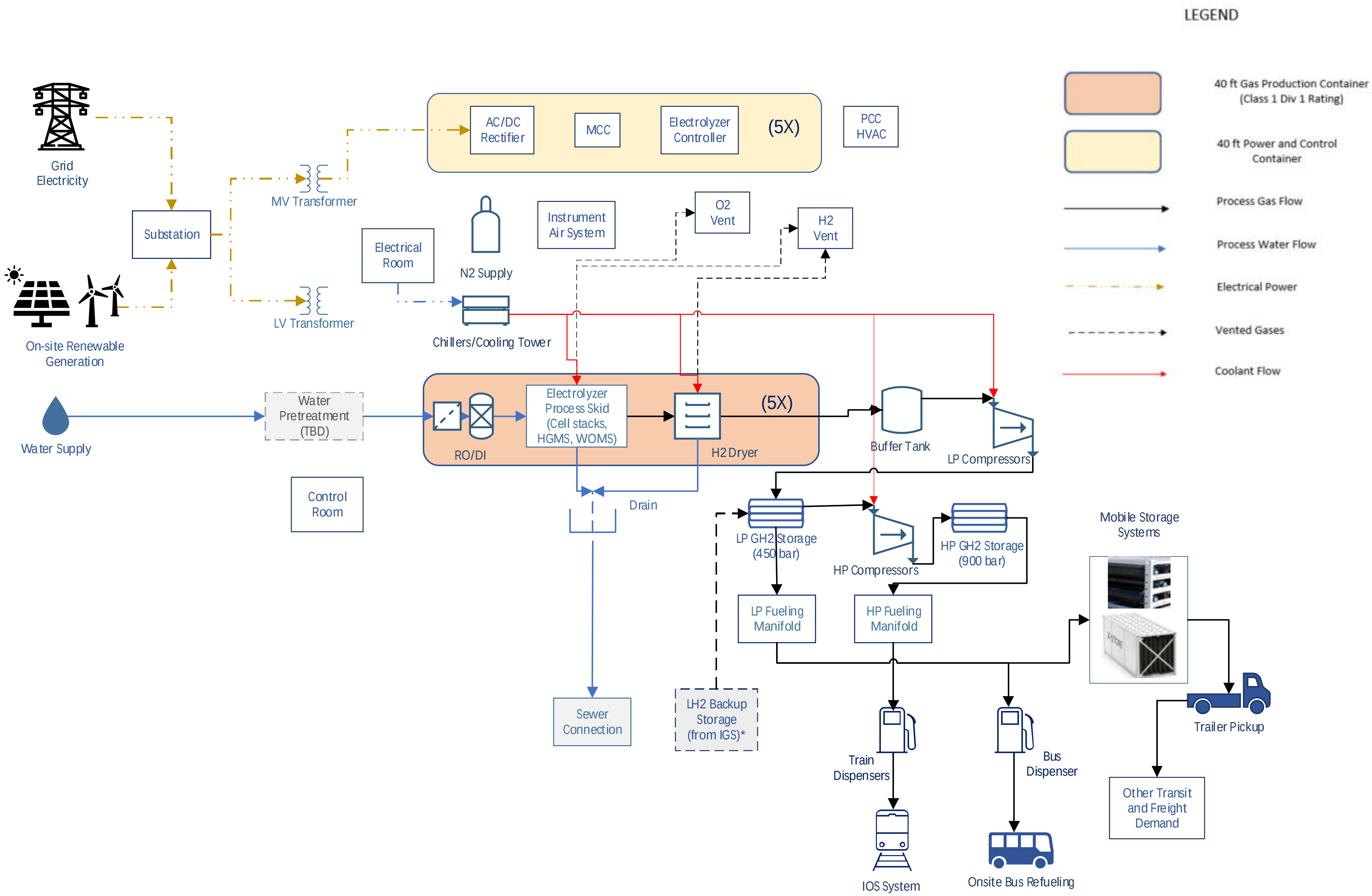


Figure 26: Process flow diagram for an electrolytic hydrogen production facility at the Tracy OMF to serve Valley Link and others

5.2. Site Layout and Key Equipment

5.2.1. Electrolyzer

The electrolyzer systems shown in the block flow diagram assume these are outdoor systems. These systems are composed of two 40 ft shipping containers for each 2.5 MW system capable of producing 1,000 kg-H2/day. The Power and Control container includes: MV rectifier, MCC. The Process container includes: Water treatment system (RO/DI), Electrolyzer stacks, Hydrogen purification system, Analyzer panel. This can be replaced with indoor electrolyzer systems, which will require the construction of a building compliant with hydrogen safety codes such as NFPA 2.

During steady state operation, the electrolyzer is projected to require ~18 L/kg-H2 of potable water, and produce ~9.5 L/kg-H2 of wastewater. The water quantities will vary based on the inlet water quality specifications, for example an agricultural water connection will require more pretreatment, therefore increasing the water demand and wastewater volumes. The minimum water quality specification after treatment is ASTM Type II (<1µS/cm; >1MΩ-cm). Figure 27 details the flow of water within the electrolyzer's process container.

Commercial PEM systems are typically capable of accepting a medium voltage electrical input ranging from 5-30 kV. This allows for direct interconnection with existing electrical distribution infrastructure at brownfield sites without requiring additional capital for transformers.

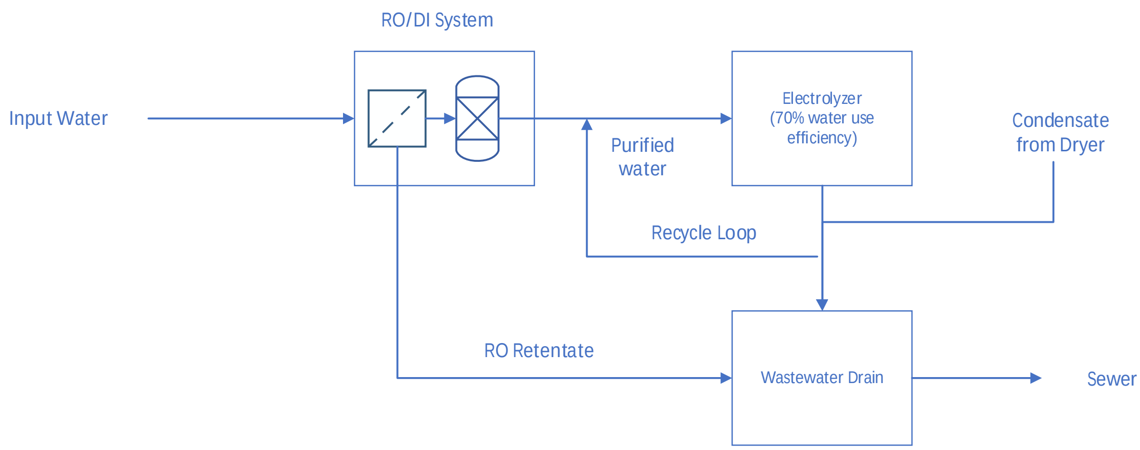


Figure 27: Electrolyzer Internal Water Balance Overview

5.2.2. Water Supply

The water supply for the electrolyzer facility is an important factor given the current and probable future drought conditions in California. This factor was addressed partially in Section 2.3. This section will focus on the local conditions and availability of water.

The Tracy OMF site is located on Schulte Road and the City of Tracy has a freshwater supply line running along Schulte Road to service "Zone 3". A map of the potable water system for the City of Tracy is shown in Figure 28. The total water demand from the on-site production electrolyzer facility at full build-out and full utilization will be 26,500 gal/day. This is 0.8% of the average daily demand and 0.5% of the max daily demand for Zone 3 of the City of Tracy potable water system[40].

Although this is a small increase in the overall freshwater demand, given the drought issues in California, other options for water supply should be considered and as noted in Section 2.3, other electrolyzer plant integrators and operators are using degraded or brackish water as supply.

The city also has plans to extend the recycled water system along Schulte Road as shown in Figure 29. This could be an option for supplying the electrolyzer. More water treatment will be required at the site but the CapEx impact should not be significant. Another option is noted in the Urban Water Management Plan[41]. The city has nine groundwater production wells that supply the city with ~6% of its demand with an expected increase in the future. This groundwater comes from the Tracy Subbasin, and this subbasin has an Upper aquifer (unconfined to semi-confined) and a Lower aquifer (confined) that are separated by the Corcoran Clay. The city draws groundwater from the Lower aquifer only because the upper aquifer has a degraded water quality that requires additional water treatment that makes it uneconomical. This degraded water from the upper aquifer could also be an option for water supply to the electrolyzer facility.

[40] Table 8-3. Buildout Potable Water Demands by Pressure Zone.
https://www.cityoftracy.org/home/showpublisheddocument/12962/637866694048270000
[41] https://www.cityoftracy.org/home/showpublisheddocument/10663/637617061148600000

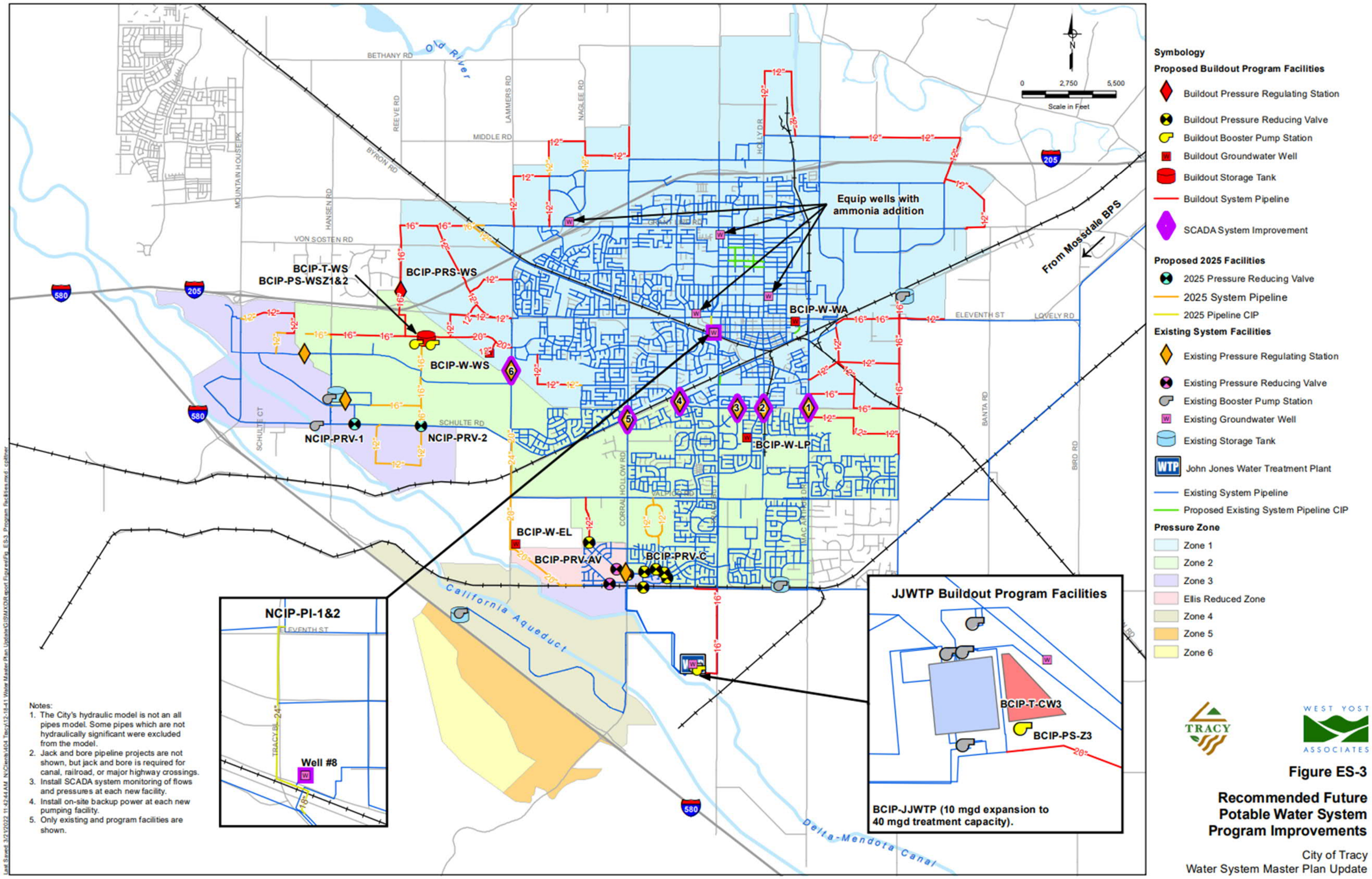


Figure 28: City of Tracy – Citywide potable water system map[42]

42 Ibid

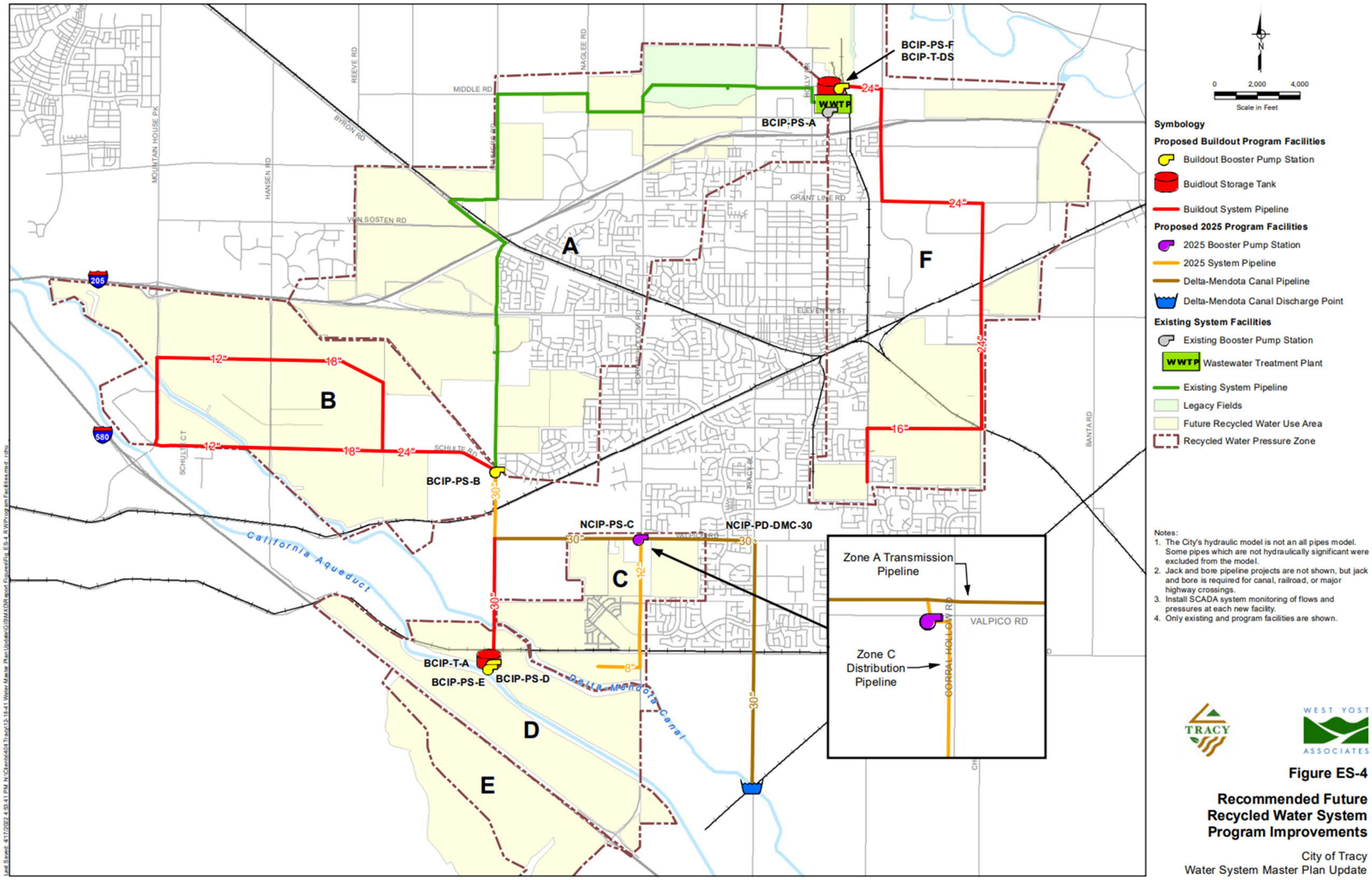


Figure 29: City of Tracy – Citywide recycled water system map[43]

[43] Ibid

5.2.3. Compression, Storage, Dispensing (CSD)

Figure 30: Diaphragm GH2 Compressor

After the hydrogen production by the electrolyzer system, compression, storage, and dispensing equipment is required in order to fill vehicles at pressures of 350 bar or 700 bar or fill the mobile storage trailers.

Figure 26 shows the two compression stages and the storage at each pressure level. In order to properly design the number of compressors and the storage sizing, a fueling profile was needed. The profile that was developed in collaboration with Valley Link is shown in Figure 31. Based upon this filling profile and the production rate of the electrolyzer, the size of the compression and storage could then be sized. However, when the first analysis was completed for an electrolyzer that was sized at exactly the peak capacity for the trains of 4,000 kg/d, the storage could not be filled in time to serve the fill profile shown. Therefore, the electrolyzer needed to be oversized. To meet the filling profile, a 1.15x oversizing of the electrolyzer was needed and the filling profile is included in the Financial Model for reference. For the filling of the buses and the mobile storage modules in the first phase no oversizing was assumed. The compressors then needed to meet this higher flow and were sized for that. The storage was sized such that the available hydrogen in storage never went negative and had some contingency (~13%) included. Eight dispensers were included for filling the trains with a chiller included for each dispenser.

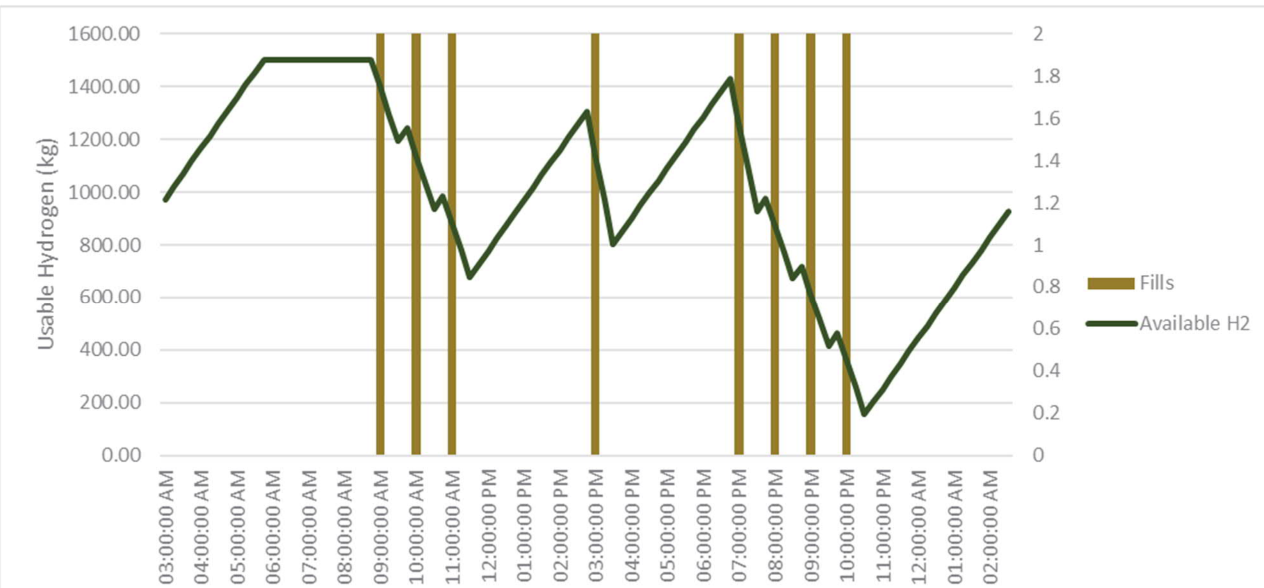


Figure 31: Fueling profile required to meet the Valley Link planned service schedule along with the available hydrogen left in the system in order to serve the fueling profile

For off-site hydrogen sales to local bus transit operators, gaseous hydrogen will be transported using mobile hydrogen storage units mounted on top of a tractor trailer and delivered by a contracted trucking operator. Figure 32 shows two commercially mobile storage systems, the HTEC PowerCube unit and the Hexagon Purus X-Store unit, which are both capable of transporting hydrogen at 450 bar.

Figure 32: Mobile 450 bar GH2 Storage Systems from HTEC (left) and Hexagon Purus(right)

5.2.4. Liquid Hydrogen Backup System

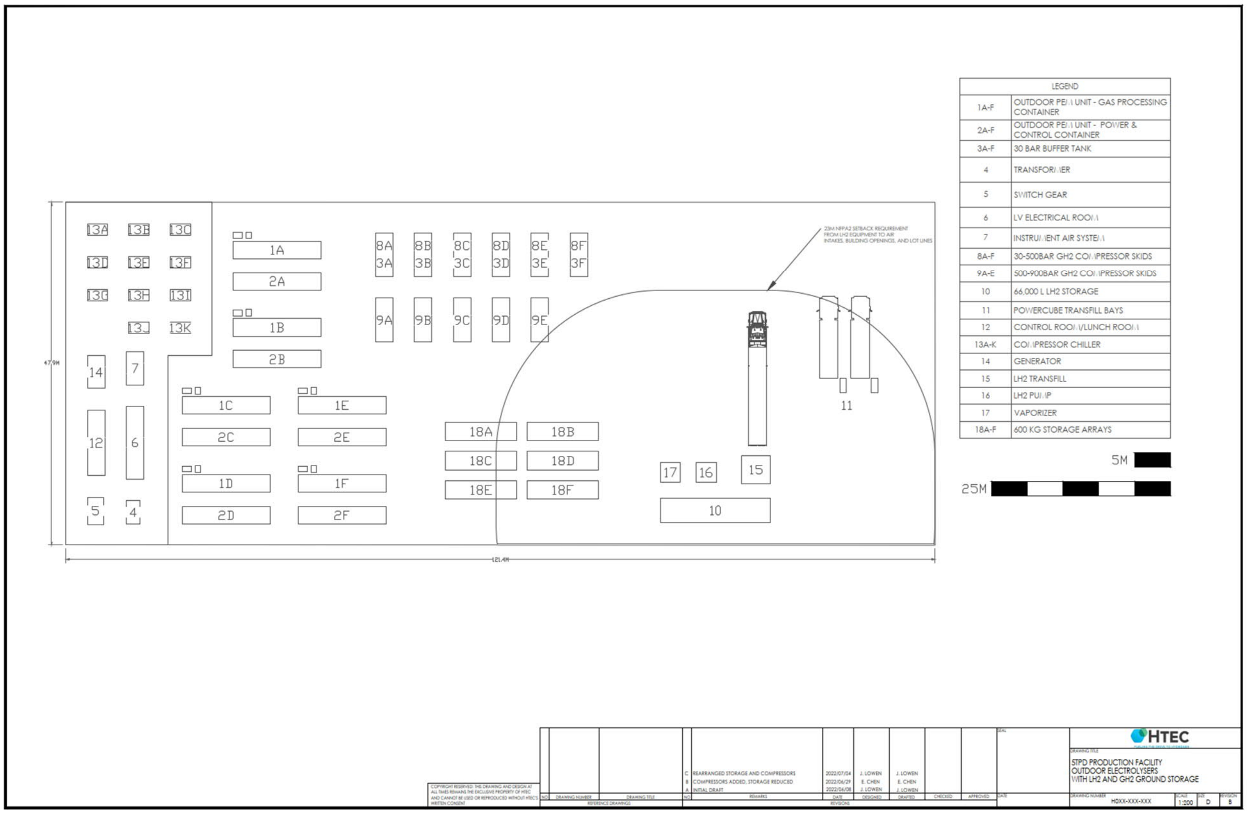
To ensure that Valley Link has very reliable service, a LH2 Backup storage with LH2 pump and vaporizer was also planned such that emergency deliveries could occur when unpredicted events happen. The LH2 backup system includes a 18,000 gallon LH2 Tank, LH2 pump, and vaporizer. The LH2 will be delivered by a hydrogen supplier with the number of deliveries occurring based on vented gas (as the liquid H2 evaporates it must be vented to maintain appropriate tank pressures) and an estimated reliability of the electrolyzer system.

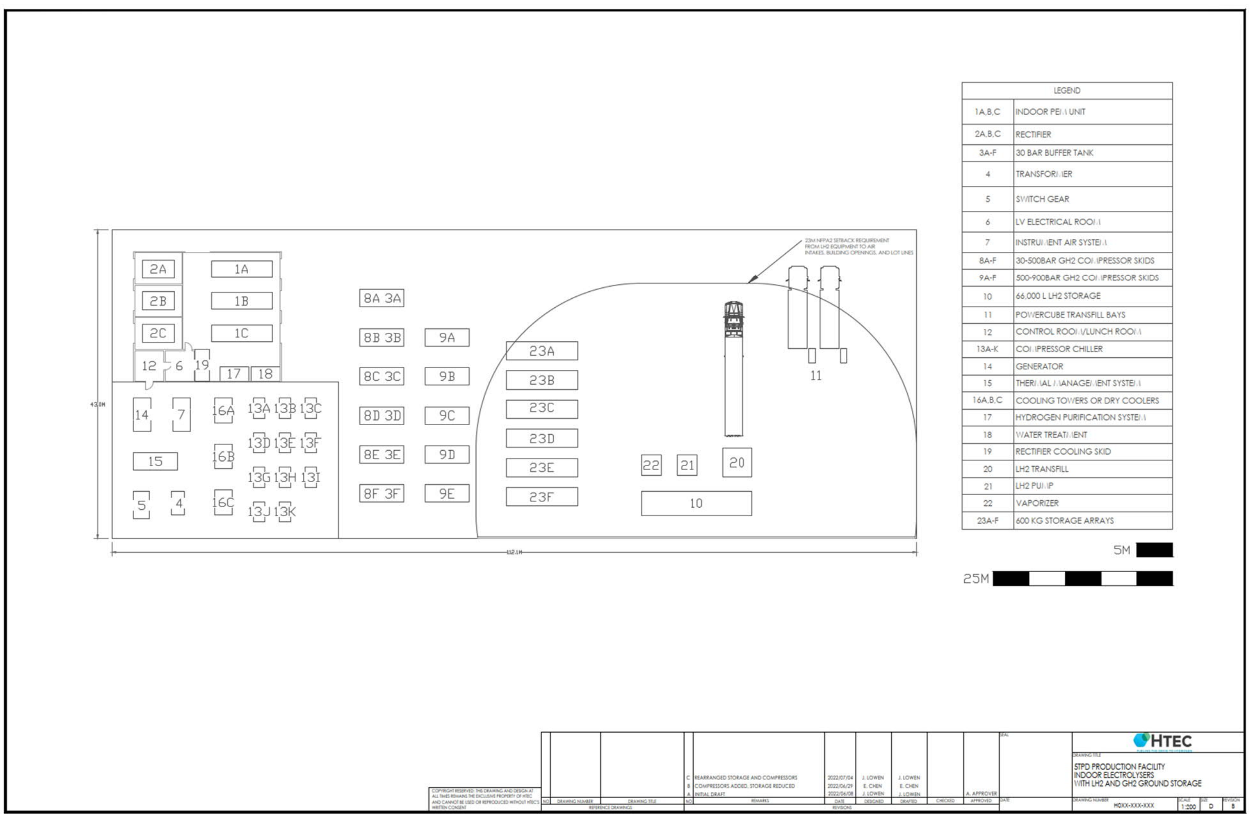
5.3. Site Layout

The California Fire Code (CFC) adopted the National Fire Protection Association 2 (NFPA 2 Hydrogen Technologies Code) for hydrogen installations. NFPA 2 provides fundamental safeguards for the generation, installation, storage, piping, use and handling of hydrogen in compressed gas or liquid form. The site layouts were constructed to conform to NFPA 2 standards such as setback distances of hydrogen equipment from hazardous exposures and other rated equipment.

Two site layouts were developed for an indoor PEM electrolyzer design and an outdoor design. The site layouts show a total of 11 compressors, which is the maximum number which the model can output. This provides an idea of the worst-case scenario for site footprint and setback considerations.

(See Appendix for full page layouts)


25M NFPA2 SETBACK REQUIREMENT FROM LH2 EQUIPMENT TO AIR INTAKES, BUILDING OPENINGS, AND LOT LINES
LEGEND
1A-F OUTDOOR PEM UNIT - GAS PROCESSING CONTAINER
2A-F OUTDOOR PEM UNIT - POWER & CONTROL CONTAINER
3A-F 30 BAR BUFFER TANK
4 TRANSFORMER
5 SWITCH GEAR
6 LV ELECTRICAL ROOM
7 INSTRUMENT AIR SYSTEM
8A-F 30-500BAR GH2 COMPRESSOR SKIDS
9A-E 500-900BAR GH2 COMPRESSOR SKIDS
10 66,000 L LH2 STORAGE
11 POWERCUBE TRANSFILL BAYS
12 CONTROL ROOM/LUNCH ROOM
13A-K COMPRESSOR CHILLER
14 GENERATOR
15 LH2 TRANSFILL
16 LH2 PUMP
17 VAPORIZER
18A-F 600 KG STORAGE ARRAYS
5M
25M
COPYRIGHT RESERVED: THIS DRAWING AND DESIGN AT ALL TIMES REMAINS THE EXCLUSIVE PROPERTY OF HTEC AND CANNOT BE USED OR REPRODUCED WITHOUT HTEC'S WRITTEN CONSENT
C REARRANGED STORAGE AND COMPRESSORS 2022/07/04 J. LOWEN J. LOWEN
B COMPRESSORS ADDED, STORAGE REDUCED 2022/06/29 E. CHEN E. CHEN
A INITIAL DRAFT 2022/06/08 J. LOWEN J. LOWEN
HTEC
STPD PRODUCTION FACILITY
OUTDOOR ELECTROLYSERS
WITH LH2 AND GH2 GROUND STORAGE
H0XX-XXX-XXX 1:200 D B


25M NFPA2 SETBACK REQUIREMENT FROM LH2 EQUIPMENT TO AIR INTAKES, BUILDING OPENINGS, AND LOT LINES
LEGEND
1A,B,C INDOOR PEM UNIT
2A,B,C RECTIFIER
3A-F 30 BAR BUFFER TANK
4 TRANSFORMER
5 SWITCH GEAR
6 LV ELECTRICAL ROOM
7 INSTRUMENT AIR SYSTEM
8A-F 30-500BAR GH2 COMPRESSOR SKIDS
9A-F 500-900BAR GH2 COMPRESSOR SKIDS
10 66,000 L LH2 STORAGE
11 POWERCUBE TRANSFILL BAYS
12 CONTROL ROOM/LUNCH ROOM
13A-K COMPRESSOR CHILLER
14 GENERATOR
15 THERMAL MANAGEMENT SYSTEM
16A,B,C COOLING TOWERS OR DRY COOLERS
17 HYDROGEN PURIFICATION SYSTEM
18 WATER TREATMENT
19 RECTIFIER COOLING SKID
20 LH2 TRANSFILL
21 LH2 PUMP
22 VAPORIZER
23A-F 600 KG STORAGE ARRAYS
5M
25M
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C REARRANGED STORAGE AND COMPRESSORS 2022/07/04 J. LOWEN J. LOWEN
B COMPRESSORS ADDED, STORAGE REDUCED 2022/06/29 E. CHEN E. CHEN
A INITIAL DRAFT 2022/06/08 J. LOWEN J. LOWEN A. APPROVER
HTEC
5TPD PRODUCTION FACILITY
INDOOR ELECTROLYSERS
WITH LH2 AND GH2 GROUND STORAGE
H0XX-XXX-XXX 1:200 D B

5.4. Stakeholder Interviews

To better understand the potential for onsite clean hydrogen production and delivered hydrogen, interviews were held with three electrolyzer OEMs (NEL, Cummins, Plug Power) and two hydrogen technology developers/integrators (Mitsui, HTEC). Table 12 below summarizes the standard questions asked and each stakeholders response and the detailed interview notes are attached in Appendix A.

Table 12: Stakeholder Interview Summary

	NEL	Cummins	Mitsui	Plug Power	HTEC
Company type	Electrolyzer supplier	Electrolyzer supplier	Integrator and CSD provider	Electrolyzer and CSD supplier	Integrator
Recommended electrolyzer solution	2. 5 MW PEM containerized	HyLYZER 500 1-2.5 MW PEM containerized	N/A	2x 1 MW containerized PEM system	N/A
Electrolyzer price	*$1700-1800/kW (incl. Electrolyzer, Power Supply/Rectifier, and Thermal Control System/Dry Cooler)*	*Waiting for NDA*	N/A	$1400 – 1500/kW *(incl. Electrolyzer, Power Supply/Rectifier, and Thermal Control System/Dry Cooler)*	N/A
Electrolyzer supply constraints	1 year for station module, 1 year for 2.5 MW electrolyzer TBC	24 months for electrolyzers right now but should decrease to 12 for this project	N/A	1 MW lead time 14 months, 5 MW containerized 16-18 months	20-24 months today for electrolyzers
Building vs. containerized system	N/A	Containerized costs more for every addition but is less risky and can be more turnkey	Not interested in investing in facility but could provide backup delivery or offtake	Containerized	Building saves on upfront and O&M costs but is more risky if demand doesn't come
Backup supply	Stacked gaseous cylinders ~500 kg @ 450 bar plus delivered gaseous	Did not discuss	Liquid or gaseous delivery from Livermore facility	Liquid storage tank plus flexibility to order liquid tanker from PP plant in Mendota	Liquid
Delivered liquid hydrogen price	N/A	N/A	~$10/kg	Sub $10/kg	N/A
Fill rate	100 kg/hr for one station/compressor	N/A	Heavy-duty station filling 780 kg/hr at 700 bar	They need to know more specs	Industry avg. 1-1.5 kg/min (60-90 kg/hr), liquid pumps 3-4 kg/min (180-240 kg/hr)

Throughout the stakeholder interviews, a number of key themes emerged, and are summarized below.

- Fueling profile is key: The fueling profile is a key technical aspect for equipment manufacturers. The filling speed required for the trains is not currently available but is it at the high end of what dispenser manufacturers are currently designing for heavy-duty applications.
- Long lead times: There are long lead times today for all equipment, but the longest lead time is for electrolyzers at 12-24 months. Lead times should decrease by the time this project goes into the development phase; however, it is important to consider when developing a project schedule.
- Operations and maintenance not provided with equipment supply: All electrolyzer OEMs had some offerings that were turnkey solutions, however, the O&M for the production facility would likely need to be provided by another company. Due in part to large demand, OEMs are focusing on designing and building the best equipment and are not currently focused on operating and maintaining the equipment.
- Liquid delivery is more cost effective than gaseous delivery for heavy-duty transportation: All stakeholders mentioned that the industry is turning towards liquid delivery for heavy-duty transport, especially if long distances are required for delivery.

6. FINANCIAL MODEL

For this feasibility study, two proforma models were used to estimate a high-level cashflow for two hydrogen scenarios at Valley Link:

1. Financial Model #1: Onsite hydrogen production facility to serve the Valley Link rail project through all three phases of project development through to the Mature Valley Link operations.
2. Financial Model #2: Liquid delivered hydrogen to serve the Valley Link rail project through all three phases of project development through to the Mature Valley Link operations.

The cashflow model estimates the levelized cost of hydrogen (LCOH), as well as potential revenue from external hydrogen sales and low-carbon fuel credits. The revenue from ticket purchases was not included in the models, so there were no estimates for the project rate of return or payback periods. A future iteration of the financial models would allow for these financial indicators to be calculated as they are incorporated in the cash flow tab.

The financial models include a number of default values and assumptions to represent realistic estimates for all parameters. However, at this this stage of the project, where there are a number of assumptions and parameters still to be refined, the models can be used to explore the impact of key parameters such as electricity price, utilization, storage capacity, and electricity strategy.

6.1. Inputs and Assumptions

For the financial models, a number of key inputs and assumptions were gathered including project phasing, production volumes and sales, general financial assumptions, electricity supply, plant design, LCFS credit revenue and energy storage strategy. The following sections provide a summary of some of the key inputs and assumptions.

Both financial models contain sources for the key inputs and assumptions for the User to understand and verify against other future project constraints that might arise. Each input and assumption will not be discussed here given the source information contained in the model, but the overall architecture and thinking behind the financial model will be discussed.

The overall architecture of the model with data inputs, data flow, submodels, and outputs are shown in Figure 33.

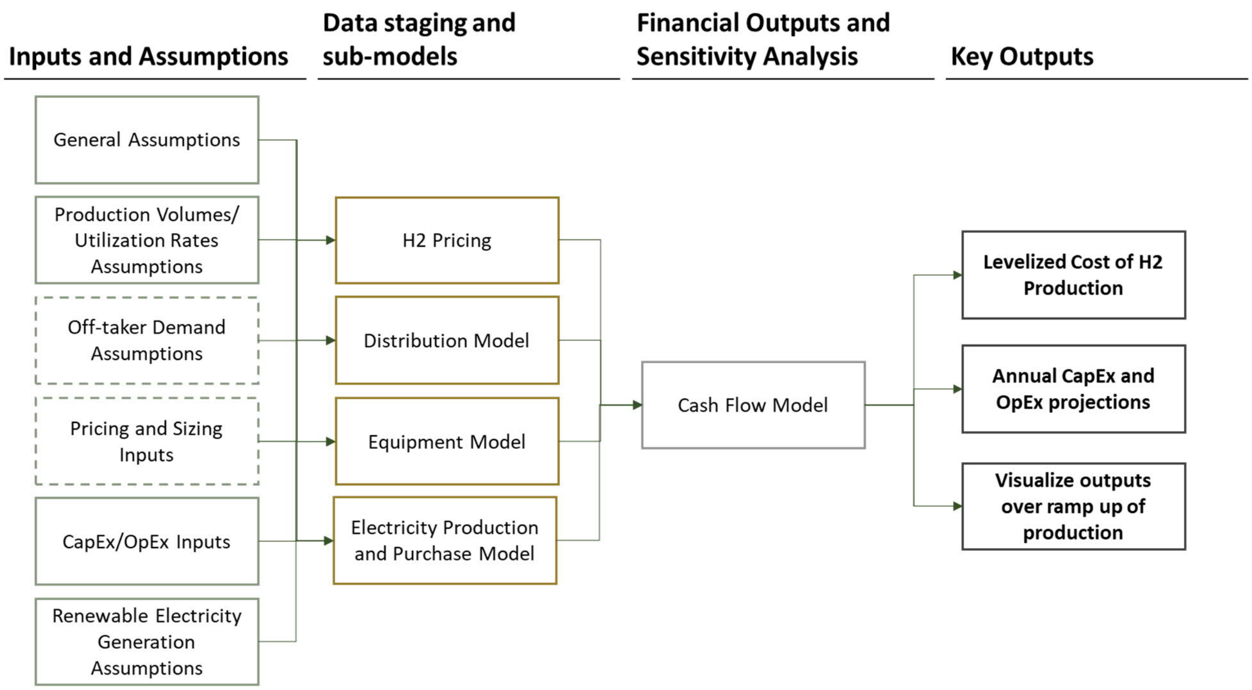


Figure 33: Financial model data staging and flow through the sub-models

6.1.1. Financial Model #1 – Onsite Hydrogen Production

As shown in Table 2, the hydrogen produced for phase 1 will serve fuel cell electric buses from local transit operators. Phases 2 and 3 represent the 26-mile initial operating segment of the Valley Link project between the BART system in Dublin-Pleasanton and the Mountain House Station. The main difference between phases 2 and 3 is an expected increase in ridership resulting in double trainsets rather than single.

In financial model #1 it was assumed that onsite renewable electricity would supply the hydrogen production facility as much as possible. There are four main scenarios or options to select from in the model:

- Option 1: Tracy OMF – 47 Acre Layout - Solar only + Grid
  - 12 MWac PV
- Option 2: Tracy Land all available - Solar only + Grid
  - 48 MWac PV
- Option 3: Tracy OMF – 47 Acre Layout - Solar with BESS + Grid
  - 12 MWac PV with BESS selected based on lowest cost when considering supply from both PV+BESS and Grid using Tables shown in Section 4.1.1
- Option 4: Tracy Land all available - Solar with BESS + Grid
  - 48 MWac PV with BESS selected based on lowest cost when considering supply from both PV+BESS and Grid using Tables shown in Section 4.1.1

6.1.2. Financial Model #2 – Delivered LH2

For financial model #2, phases 2 and 3 remain the same as in Table 2, but phase 1 is not included as the FCEBs would not be served by delivered liquid hydrogen at the Tracy facility.

The delivered LH2 model assumes LH2 delivered to the LH2 refueling station at the Tracy OMF for a set price defined by the user with a default value based on vendor discussions. The main components of the LH2 station are a LH2 storage tank, pump, vaporizer, GH2 storage tubes, chiller, and dispenser. The assumptions and equipment are detailed in the model.

This model was included to provide a baseline to compare with the onsite production options.

6.2. Financial Outputs and Sensitivity Analysis

To clearly outline the different options and scenarios analyzed, they are listed below:

- Financial model #1 - Onsite Electrolytic Hydrogen Production from Solar PV and grid electricity
  - For each option below, two levels of sales of excess hydrogen production capacity (after sales to local bus transit operators) were evaluated since the electrolyzer will have excess capacity due to several factors that include oversizing to meet the specific fueling profile of Valley Link and lower demand weekend days: 0% and 100%
    - Option 1: Tracy OMF – 47 Acre Layout - Solar only + Grid
    - Option 2: Tracy Land all available - Solar only + Grid
    - Option 3: Tracy OMF – 47 Acre Layout - Solar with BESS + Grid
    - Option 4: Tracy Land all available - Solar with BESS + Grid
- Financial model #2 – Delivered LH2 to refueling station at Tracy OMF
  - Two levels of sales of excess hydrogen dispensing capacity were evaluated due to the lower demand on weekends: 0% and 100%

Another parameter of significant importance is the grid electricity price. An average electricity price was used because the team has not yet solicited input from a renewable developer or CCA provider. Partnering with a renewable developer would allow the team to better understand what options there may be for achieving a lower grid electricity price with a lower carbon intensity. This is a subject for future study and the financial model allows this to be investigated.

6.2.1. Financial Model #1: Onsite Electrolytic Hydrogen Production from Solar PV and grid electricity - 0% Sales of Excess Hydrogen

Figure 34 shows the levelized cost of hydrogen (LCOH) for the different project options with breakout among the different major cost categories, which are:

- LH2 Backup Deliveries – costs associated with the LH2 refueling system for backup purposes
- Electrolyzer stack replacement – costs associated with the electrolyzer stack replacement
- Equipment maintenance – costs to maintain equipment

- Water Input and Wastewater Disposal – costs for water feedstock and wastewater treatment
- REC OpEx – costs associated with purchasing Renewable Energy Certificates (REC) for grid purchased electricity (this was not implemented in the options and scenarios presented in this report but is a capability of the model)
- Comp/Liq + Storage Electricity – costs associated with electricity purchases for compression, storage and the balance of plant (BOP) equipment
- Production electricity – costs associated with electricity purchases for hydrogen production via electrolysis
- Comp/Liq + Storage Equipment – CapEx costs for installation of compressor, storage and other BOP equipment
- Production equipment – CapEx costs associated with installation of electrolyzer system package
- Energy Storage Facility - CapEx costs associated with installation of BESS
- Solar PV Facility – CapEx costs associated with installation of solar PV plant

Levelized costs are calculated here by discounting all the projects costs to a net present value (NPV) and then dividing by the discounted production rates of the plant. The LCOH can roughly be thought of as what the price of hydrogen would need to be for breakeven. By breaking down the levelized cost by category, the contribution of the different cost categories to the overall cost can be observed.

The LCOH for the different project options are very high when compared to typical delivered hydrogen pricing quoted by suppliers in this project ($8-10/kg), however, this does not typically include the additional compression, storage and dispensing (CSD) equipment for refueling vehicles which the scenarios below do. The LCOH would increase by another $2-4/kg for that equipment. Project options 2 and 4 are still very high comparatively and this is a result of a PV plant that is much larger than the electrolyzer load (48 MW vs. 12 MW) which results in significant excess unneeded electricity. Since the LCOH only looks at project costs, no revenues from excess electricity sales are included. See Figure 35 for the impact of project revenue streams (e.g., selling excess electricity) on the net LCOH.

The most significant cost categories are those associated with electricity supply: “Production Electricity” OpEx, Solar CapEx. Following those are the “Production Equipment” (electrolyzer) and the energy storage facility. The variation in “Production Electricity” OpEx across the options is due to the variation in how much grid electricity is required for the system.

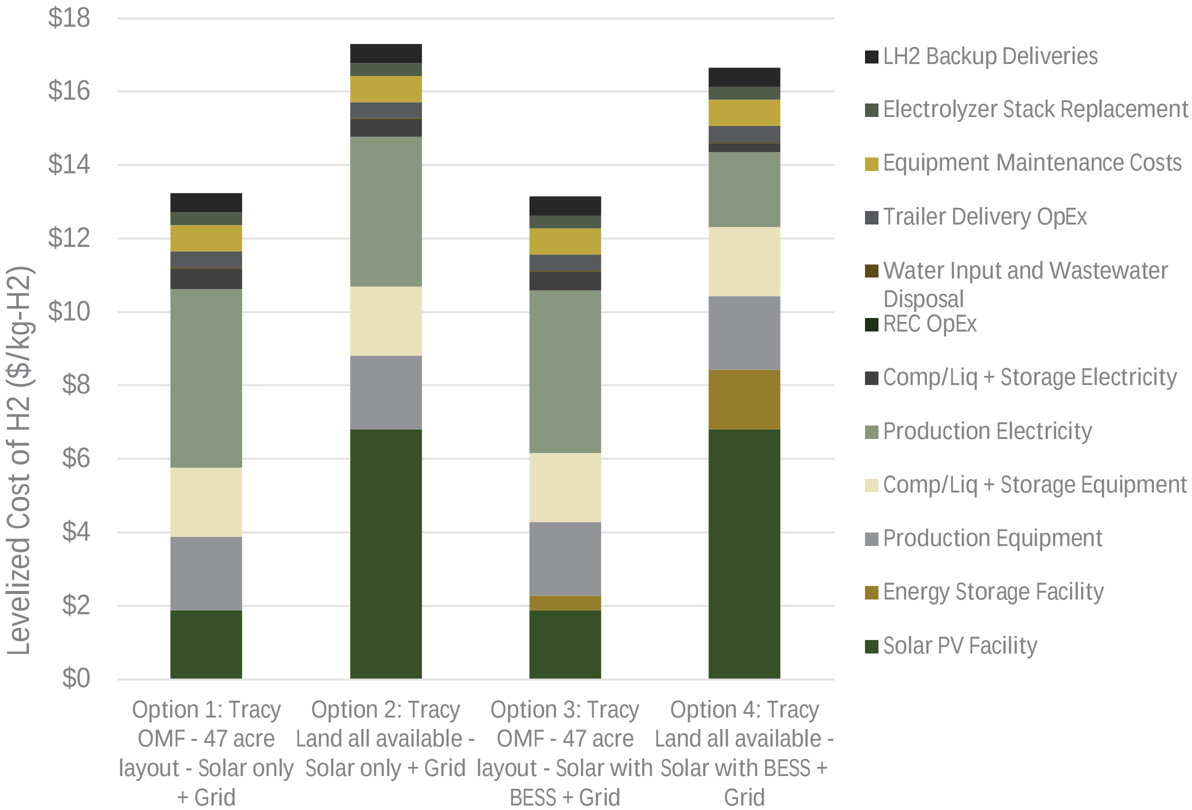


Figure 34: Levelized cost of hydrogen for 4 different options with 0% sales of excess hydrogen production capacity after serving Valley Link and local bus transit operator hydrogen demand

Figure 34 only shows the project costs and there is significant revenue potential in some of the project options. Figure 35 shows the total levelized cost per unit with the impact from any revenue generated by the project. These revenue streams include excess PV electricity sales, LCFS credits, sales to local bus transit operators, and any other sales which for the case in Figure 35 is 0%. All excess PV electricity sales occur at $40/MWh and the sales of hydrogen all occur at $8/kg in Figure 35. Option 1 and 3 do not have any excess electricity sales after Phase 3 and so those impacts are only from LCFS credits and sales to local bus transit operators. Option 2 and 4 have more significant electricity surplus, and those sales can have a large impact on the net levelized cost.

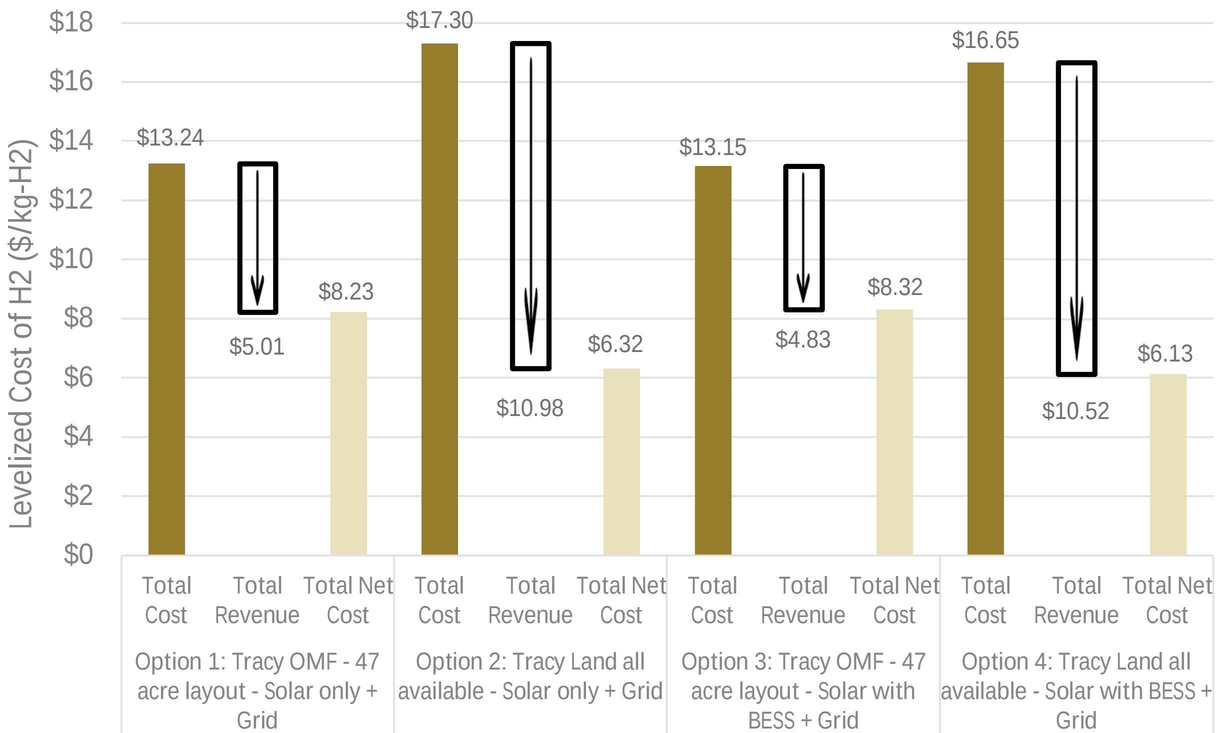
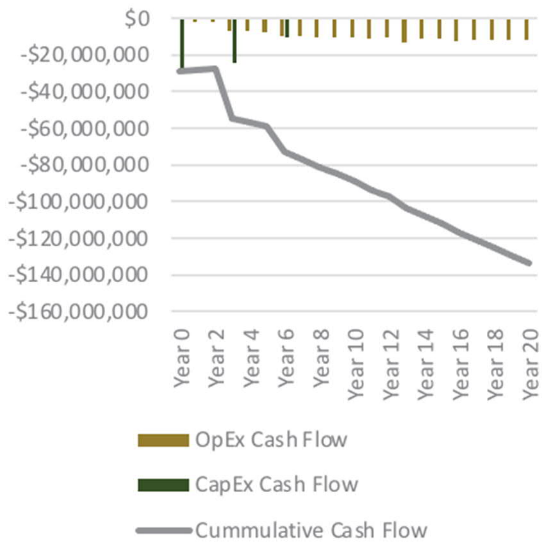
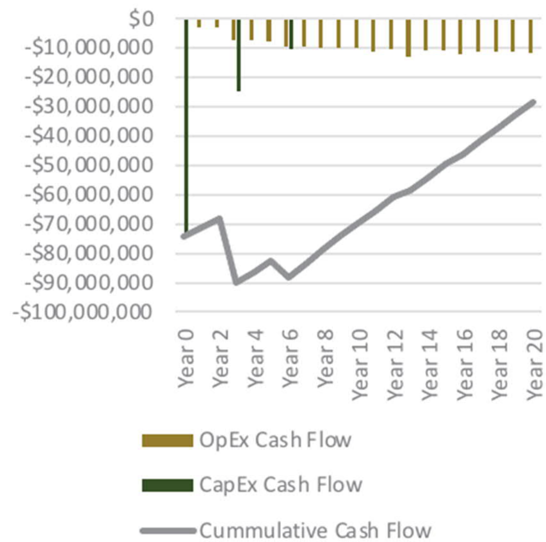


Figure 35: Levelized cost of hydrogen and the impact of revenue sources (LCFS, H2 sales, excess electricity sales) for 4 different options with 0% sales of excess hydrogen production capacity after serving Valley Link and local bus transit operator hydrogen demand

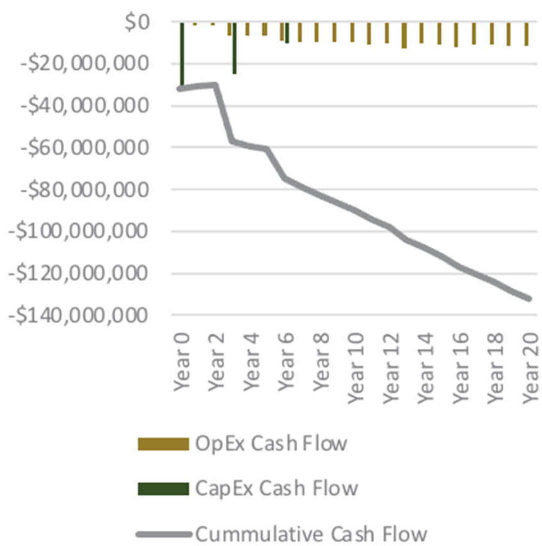
Another important way to look at the project financially is to view the cash flows over the years. Figure 36 shows the CapEx, OpEx, and cumulative project cash flows. Again, the importance of the revenue streams in Option 2 and 4 from the excess electricity can be seen. Those projects almost reach a net positive cumulative cash flow without accounting for ticketing sales. Increasing the sales of excess capacity will be important to driving toward a net positive cash flow earlier. This is discussed in the next section.



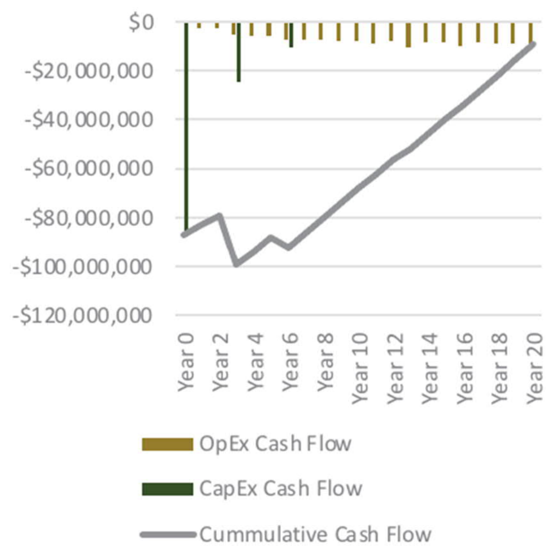
a) Option 1: Tracy OMF – 47 Acre Layout - Solar only + Grid



b) Option 2: Tracy Land all available - Solar only + Grid



c) Option 3: Tracy OMF – 47 Acre Layout - Solar with BESS + Grid



d) Option 4: Tracy Land all available - Solar with BESS + Grid

Figure 36: Cash flows for the different onsite production project concept options with 0% sales of excess hydrogen production capacity after serving Valley Link and local bus transit operator hydrogen demand

Figure 37 shows the carbon intensity of the different options analyzed. The Options that use more grid electricity result in higher carbon intensities. The carbon intensity of grid electricity can be offset through the purchase of Renewable Energy Certificates (RECs). These are currently in the $20/MWh range and can bring the carbon intensity down to 4.7 g-CO2e/MJ-H2 in Phase 3 of all the project options. For reference, carbon intensities for hydrogen in the LCFS are shown in Figure 38. There is a large range of hydrogen carbon intensities with an average around 20 g-CO2e/kg-H2. Although significant volumes are sold at higher carbon intensities, the negative carbon intensities bring the average down to 20.

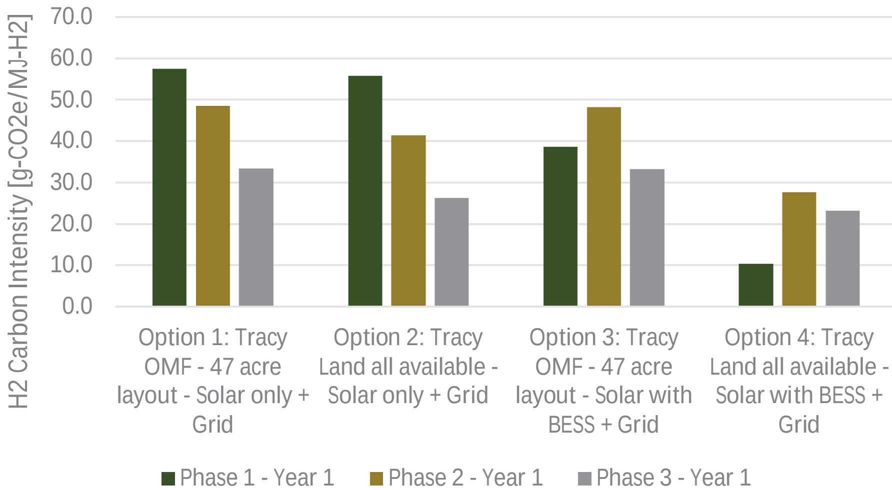


Figure 37: Carbon intensity of the hydrogen dispensed in each onsite hydrogen production project option and each project phase (note: the carbon intensity of the California grid will decrease for future phases)

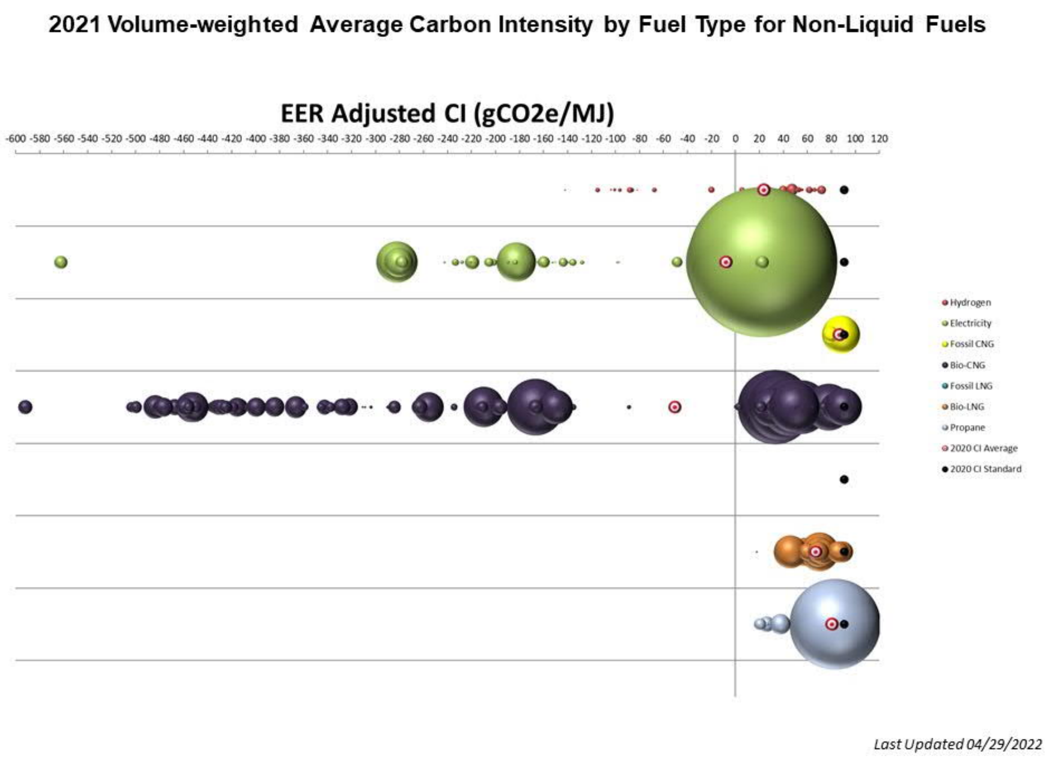


Figure 38: Carbon intensities of non-liquid fuels in the LCFS program[44]

[44] https://ww2.arb.ca.gov/resources/documents/lcfs-data-dashboard

Figure 39 shows the effect of +/- 20% changes in different financial model parameters for Project Option 4 with 0% excess capacity sales. For this Project Option, the LCOH was $6.13/kg. The parameters varied here represent those that are most impactful as well as those that frequently generate questions from stakeholders (e.g., water costs). The most important parameters all have to do with electricity, and how much the project can buy it for, produce it for, and sell it for. The electrolyzer is also a very important parameter but will not be shifting by +/- 20% between now and 2025/30 timeframe. The H2 sale price and the LCFS credit price are also important parameters that will affect the net LCOH. Besides these parameters, the other impactful parameter is whether the project can sell the excess hydrogen capacity it has. The project will have excess hydrogen capacity due to 1) lower weekend demand and 2) oversizing of the electrolyzer to meet the train fueling profile. The next section addresses this parameter.

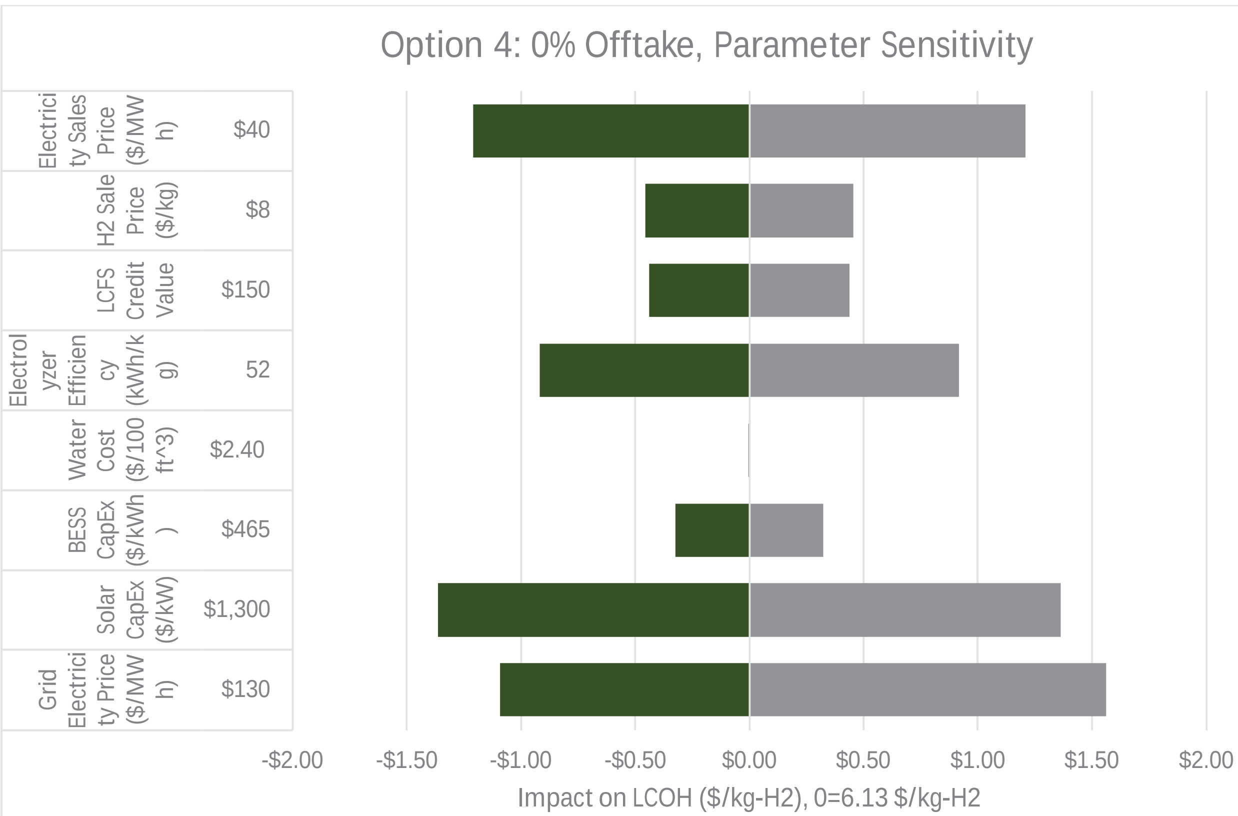


Figure 39: Effect on LCOH of +/- 20% changes in different financial model parameters for Project Option 4 with 0% excess hydrogen production capacity sales

6.2.2. Financial Model #1: Onsite Electrolytic Hydrogen Production from Solar PV and grid electricity - 100% Sales of Excess Hydrogen

Figure 40, Figure 41, and Figure 42 were all developed for comparison to the figures for 0% sales of excess hydrogen capacity in the previous section. Note the significant reductions in LCOH for each of the project options by achieving full equipment utilization. It will be important for the Project to seek additional hydrogen sales such that equipment is fully utilized.

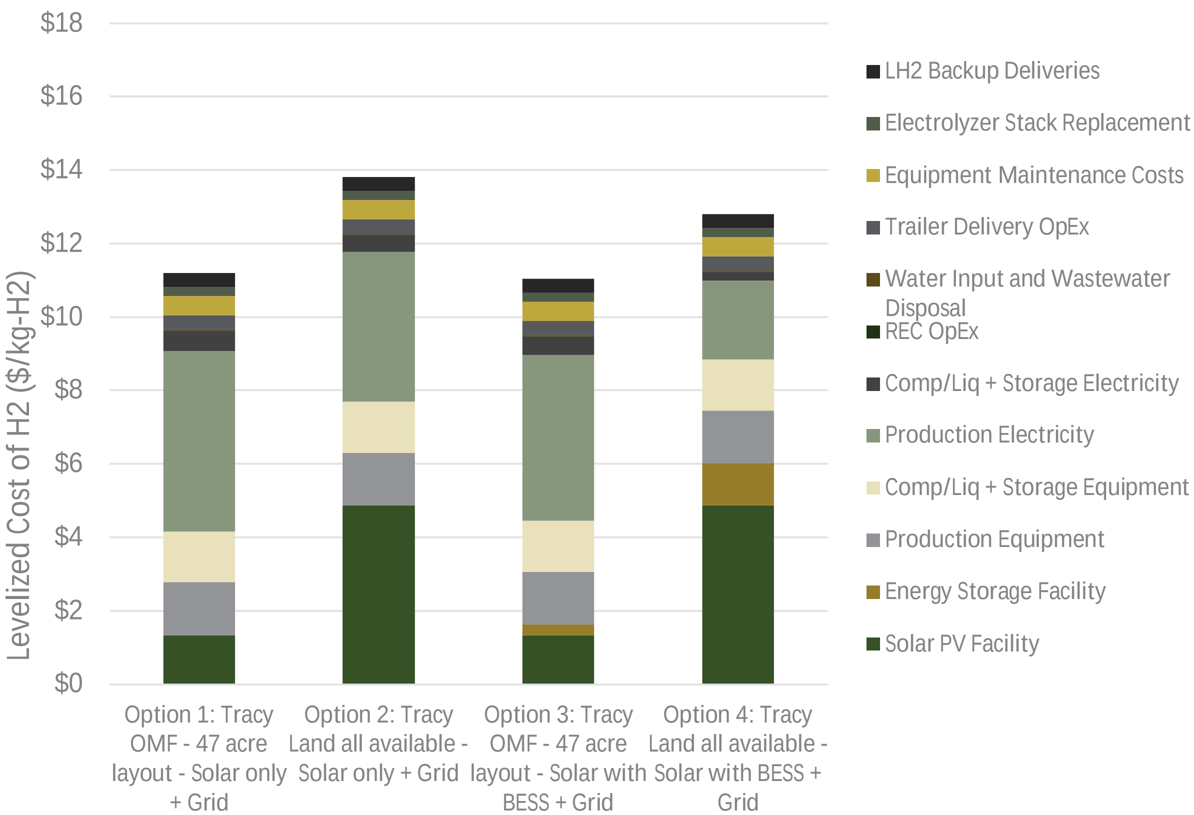


Figure 40: Levelized cost of hydrogen for 4 different options with 100% sales of excess hydrogen production capacity after serving Valley Link and local bus transit operator hydrogen demand.

The additional revenue potential from these excess capacity sales can also be significant. Project Option 4 achieves a total net LCOH of $1.95/kg. Again, it will be important for the Project to seek additional hydrogen sales.

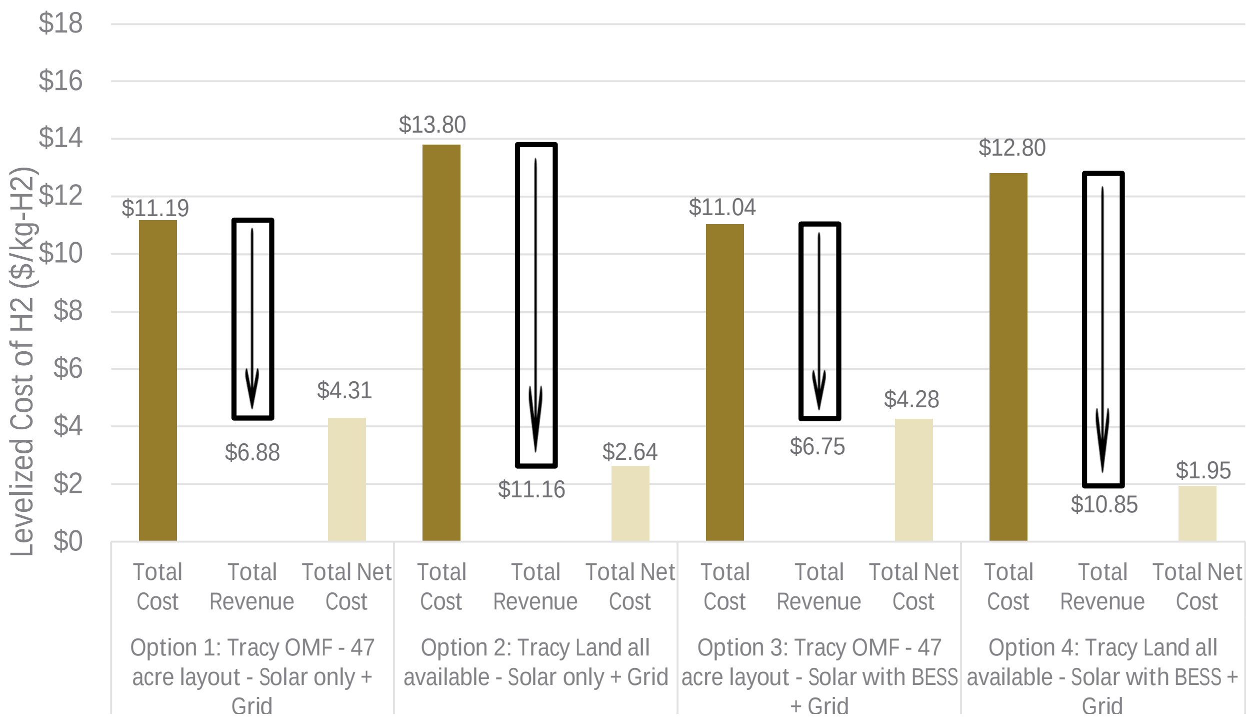
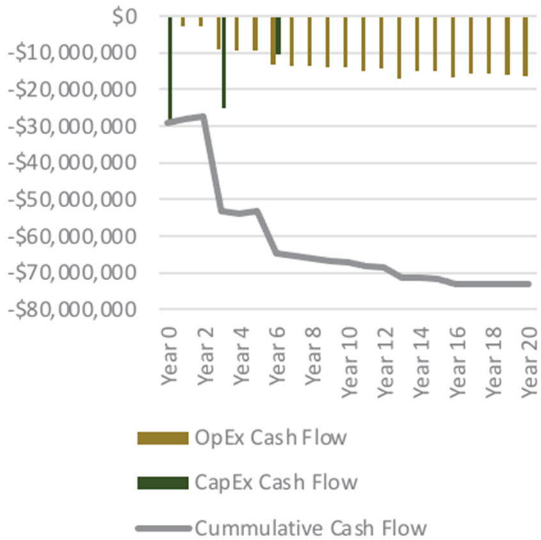
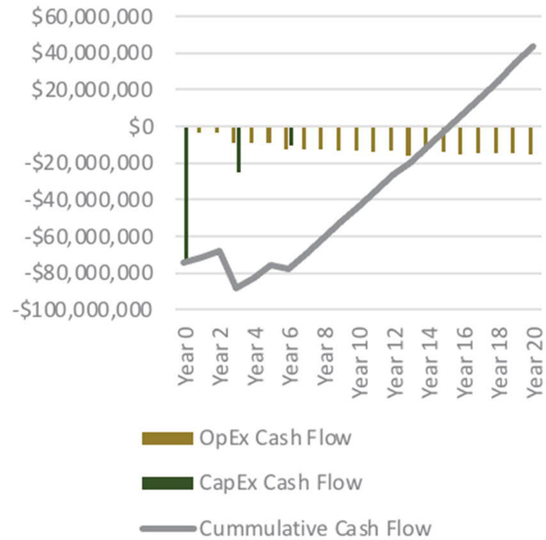


Figure 41: Levelized cost of hydrogen and the impact of revenue sources (LCFS, H2 sales, excess electricity sales) for 4 different options with 100% sales of excess hydrogen production capacity after serving Valley Link and local bus transit operator hydrogen demand

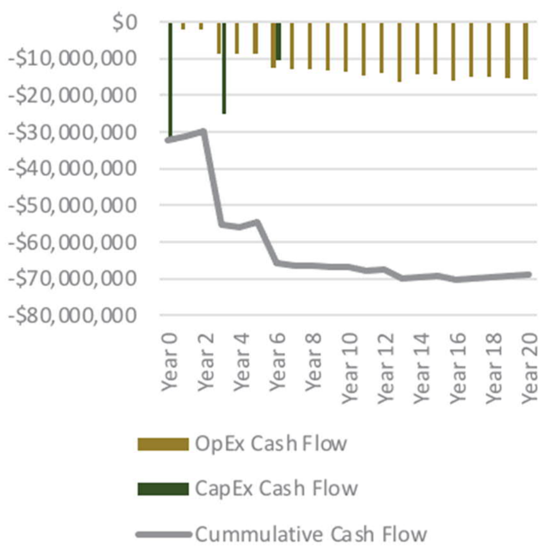
The cumulative cash flow in Options 2 and 4 achieve positive cashflow several years earlier than in the case of 0% excess hydrogen capacity sales.



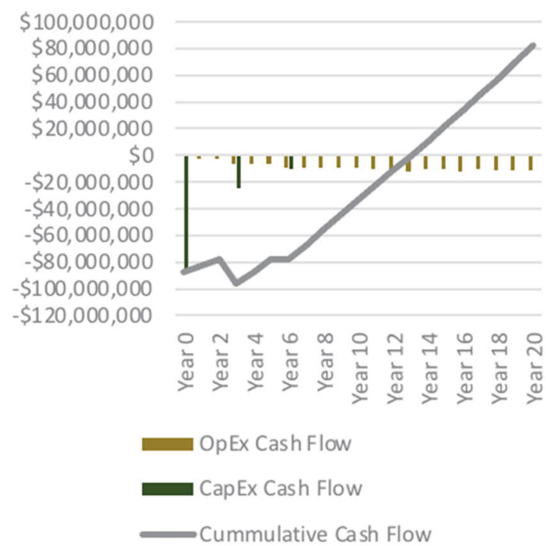
a) Option 1: Tracy OMF – 47 Acre Layout - Solar only + Grid



b) Option 2: Tracy Land all available - Solar only + Grid



c) Option 3: Tracy OMF – 47 Acre Layout - Solar with BESS + Grid



d) Option 4: Tracy Land all available - Solar with BESS + Grid

Figure 42: Cash flows for the different onsite production project concept options with 100% sales of excess hydrogen production capacity after serving Valley Link and local bus transit operator hydrogen demand

6.2.3. Financial Model #2: Delivered LH2

Given the complexity of the onsite production project options associated with Financial Model #1, a baseline Financial Model was developed for comparison to a project with less complexity, i.e., hydrogen delivered to the site from a centralized production facility. Various discussions were had with different suppliers to understand the pricing available. Based on those discussions, delivered LH2 to Valley Link was assumed to cost $8/kg with a carbon intensity of 15 g-CO2e/MJ-H2. The details of all the inputs are included in the Excel model that accompanies this report.

Figure 43 shows the LCOH for the delivered LH2 project option where no excess dispensing capacity is sold and where all the excess dispensing capacity is sold. This is similar to the analysis done in the previous section for the onsite production options. There is excess dispensing capacity for similar reasons mentioned in the onsite production section. The LH2 pumps need to be able to provide enough dispensing capacity for the peak refueling hour, and there is also lower demand on the weekend. Both of these result in the system having some excess capacity. Comparing these LCOH to those in the respective figures of the prior sections (Figure 34 and Figure 40), it is apparent that the delivered LH2 project option is a lower cost option. However, there is more revenue potential associated with the onsite production project options such that the net LCOH in Figure 44 is not lower than the net LCOH for the onsite production options 2 and 4 in Figure 35. Once the excess hydrogen capacity is considered, the revenue potential grows further, however, onsite production options 1 and 3 do not have a net LCOH lower than the delivered LH2 option. It should also be noted that the LCOH is dominated by the OpEx for hydrogen delivery. The LCOH is only one metric in financial analysis. Figure 45 shows the cumulative cash flow for the project. This shows that the delivered LH2 project option will never reach positive cumulative cash flow.

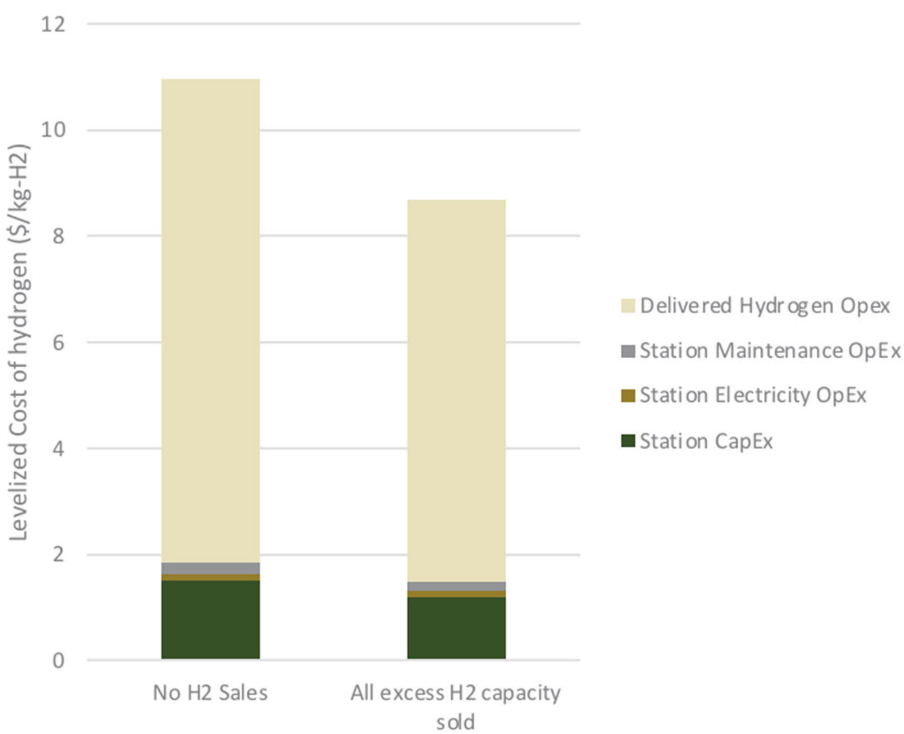


Figure 43: Levelized cost of hydrogen for the delivered LH2 project concept option with 0% and 100%

sales of excess hydrogen dispensing capacity

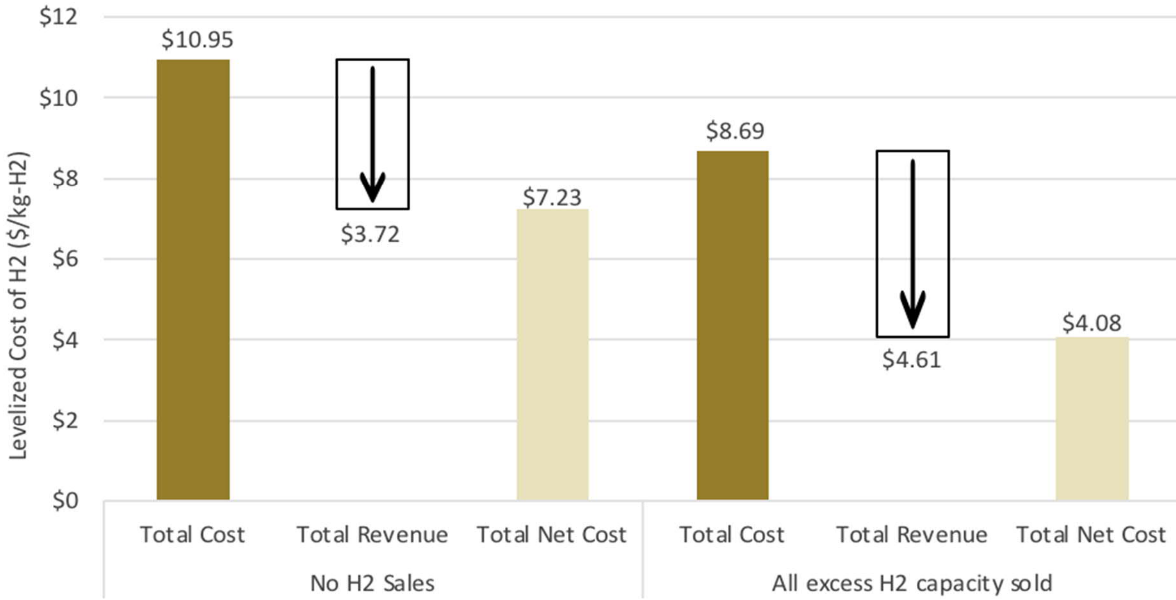
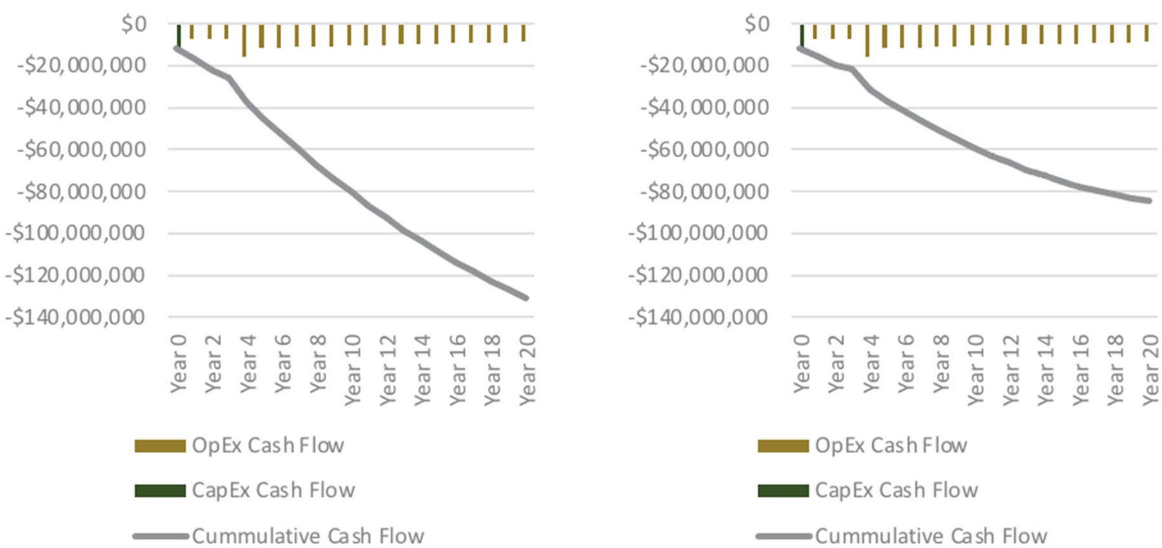


Figure 44: Levelized cost of hydrogen and the impact of revenue sources (LCFS and H2 sales) for the delivered LH2 project concept option with 0% and 100% sales of excess hydrogen dispensing capacity



a)

Figure 45: Cash flows for the delivered LH2 project concept option with (a) 0% and (b) 100% sales of excess hydrogen dispensing capacity

Figure 46 shows the other non-financial metric of importance: carbon intensity (although this ends up of having an important indirect impact financially due to the LCFS program). Comparing to Figure

37, the carbon intensity of the delivered LH2 project option outperforms all the onsite production options (except Option 4 in Phase 1). However, if RECs were to be purchased for any grid electricity used in the onsite production options, then the onsite production options would outperform the delivered LH2 option.

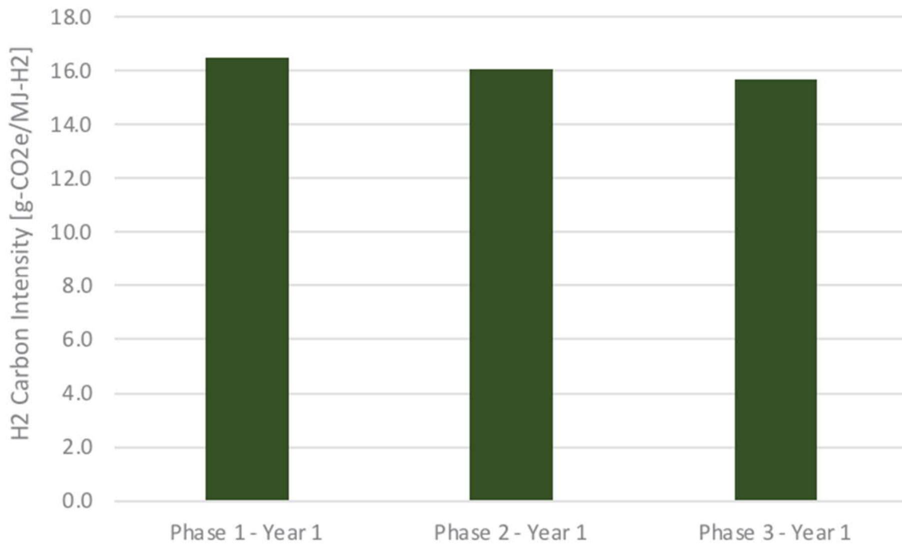


Figure 46: Carbon intensity of the hydrogen dispensed for the delivered liquid hydrogen project option in each project phase (note: the carbon intensity of the California grid will decrease for future phases)

6.3. Financial Model Conclusions

Given the various options analyzed and the comparison of financial metrics and the carbon intensity for the different options, Figure 47 was developed to allow comparison amongst the project options using both a financial metric and carbon emissions metric. Figure 47 shows the ratio of overall project NPV and the resulting carbon emission reductions from the project relative to the Diesel base case analyzed in the Environmental Impact Report (EIR)[45]. All of the project options considered result in lower carbon emissions versus the Diesel base case in the EIR. Figure 47 shows additional results to those shown in the prior sections, i.e., cases where the project options purchase RECs to ensure that all grid electricity consumed is 100% renewable with a carbon intensity of 0 g-CO2e/MJ-electricity. The price of these RECs was assumed to be $20/MWh. The reason for including this analysis was that project Options 1 and 3 were not competitive (based on this $NPV/tonne-CO2e-reduced metric) with the other project options due to the large amount of grid purchases required in those options. Figure 47 also shows error bars representative of +/-20% given the number of assumptions made in these analyses. These error bars give some visualization to the likely spread in this metric as each project evolves in design specifics.

[45] See Table 3.8-5. https://www.Valley Linkrail.com/_files/ugd/95df9a_a81455bc12234037abf79eeb8c0c7094.pdf

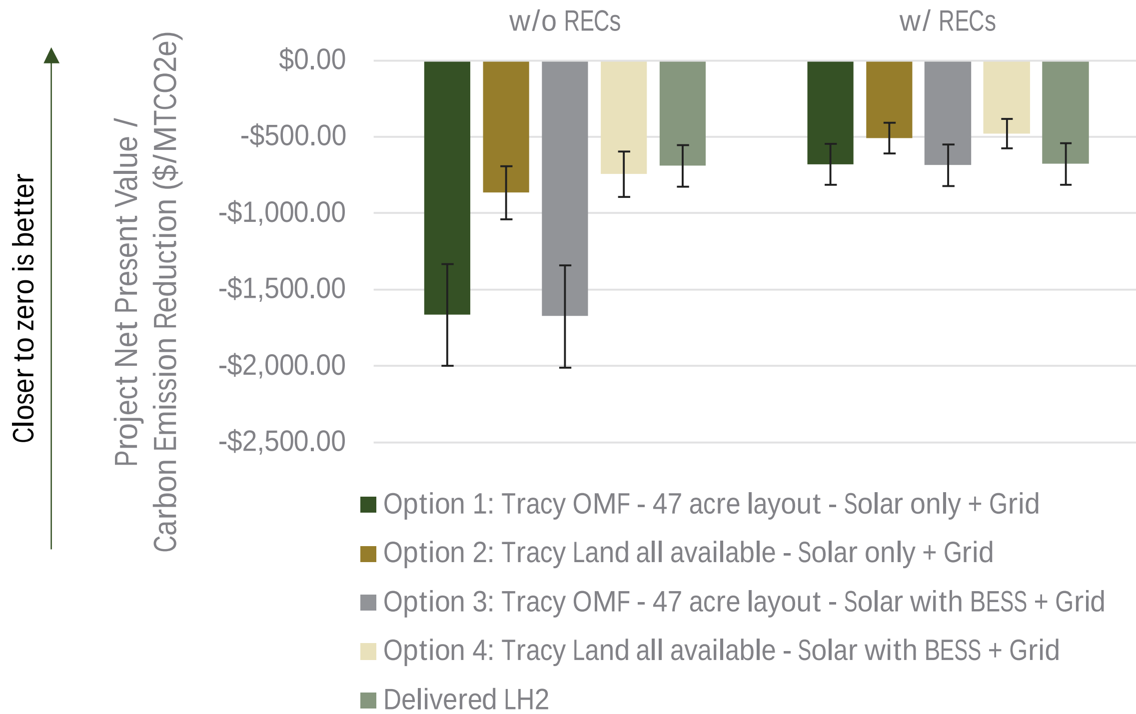


Figure 47: Comparison of the ratio of project NPV and the resulting carbon emission reductions vs. the diesel base case in the EIR for each of the project options considered, including scenarios in which RECs were purchased to reduce the carbon intensity of grid electricity used

Using this ratio of project NPV and the resulting carbon emission reductions, the importance of purchasing RECs for the onsite production project options is apparent, particularly for Option 1 and 3. Option 2 and 4 are nearly competitive with the delivered LH2 option especially Option 4 without purchasing RECs. However, once RECs are purchased to reduce the grid electricity carbon intensity, Options 2 and 4 outperform the delivered LH2 option, and Option 1 and 3 become competitive with it. Although the project complexity with the onsite production options introduces more risk, these projects also offer the best opportunity to reduce carbon emissions at the lowest cost. Additionally, the risk brought on by an onsite production opportunity can be mitigated by reducing the CapEx cost through other grant programs (e.g., becoming a part of the California hydrogen hub proposal to the US DOE) as well as developing public-private partnerships with entities that specialize in the project areas covered. This is discussed in the next section.

7. PROJECT FINANCING AND METHODS OF PROCUREMENT

There are a number of options for project procurement and financing for a facility of this scale. The options for procurement discussed in this report include traditional procurement, public private partnerships (P3s), and a private company.

As the onsite hydrogen production model is more complex, it will be the focus of the project financing option discussion going forward, however the same benefits and risks apply to both the onsite production and delivered LH2 models.

Additionally, it should be noted that the project financing options discussed here are limited to the hydrogen production facility and fueling station, any contracts or agreements related to the design and build of the energy farm should be considered separately. Although the energy farm contracts should be dealt with separately from the production facility, they could be integrated into P3 agreements by including the private renewable energy developer as a partner.

7.1. Traditional Procurement

Traditional procurement options include all service options where the Valley Link as the public sector entity would own and manage the production asset and go out to bid for various parts of the project, such as design and then build as separate contracts. Traditional procurement options allow for more control of the project and more flexibility allowing for contracts with a number of different groups for design, build, operate and maintain, however with that flexibility comes inherent risk. With shorter contracts and different entities involved in different stages of the project, setbacks and budget overruns are common challenges that public sector infrastructure projects commonly face. An alternative procurement method that many public sector infrastructure projects look towards are public private partnerships otherwise known as P3s or P3 agreements. The key differences between traditional procurement and P3s are that P3s usually include longer-term contracts (20-50 years) and cover multiple parts of the project under one agreement. See figure below for key differences.[46]

[46] https://www.ivey.uwo.ca/media/1964203/comparing-p3-and-traditional-approaches.pdf

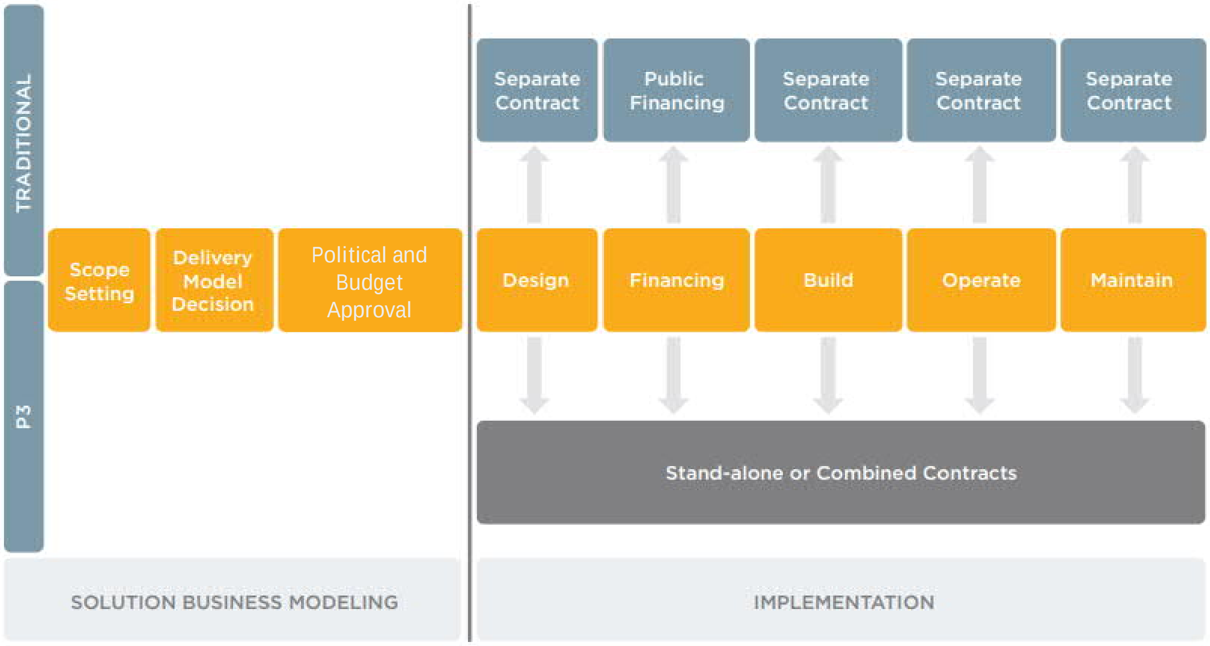


Figure 48: Key differences between traditional procurement and P3 agreements

7.2. Public Private Partnerships

7.2.1. Overview

P3s are becoming popular methods of procurement as an alternative to the traditional method outlined above. P3s are usually longer-term contracts (5-50 years) that cover multiple parts of a project (design, build, finance, operate, maintain) under one agreement between a public sector entity and one or more private companies. P3 agreements often take more time and money to create and a lot more of the design and finance modeling is done upfront before the agreement begins. It is commonplace for the public sector entity to hire an owner's representative that has relevant expertise that can work with the public entity to develop initial project scoping and financial modeling in preparation for a Request for Proposals (RFP) for a private entity partner(s). As the P3 agreement preparation stage of the project is where the public sector entity takes on the most risk, the owner's representative will be important for a successful project. Additionally, the owner's representative will work with the public entity throughout the lifecycle of the P3 agreement to ensure various performance metrics are being met, some of which are not easily calculated (e.g., equipment availability for dispensing). Once the P3 agreement has been signed, it offers public sector entities a number of opportunities, which are outlined below:

- P3 agreement is usually tied directly to lifecycle performance of the facility
- Where P3 agreements include design and build as well as operate and maintain, there is less risk associated with the O&M part of the project as it was designed for by the partnership
- Allows public sector to focus on core services and competencies and allows the P3 to access

additional sources of revenue

- Sharing of risk throughout the entire lifecycle of the project
- Allows both the public sector entity and private company to access other sources of funding

P3 agreements cover a wide range of agreements. The figure below shows the level of public vs. private sector involvement and some example agreements. It is disputed whether design-build qualifies as a P3 or a public contract. For the purpose of this report, any agreement that includes more than one part of the project will be considered a P3.

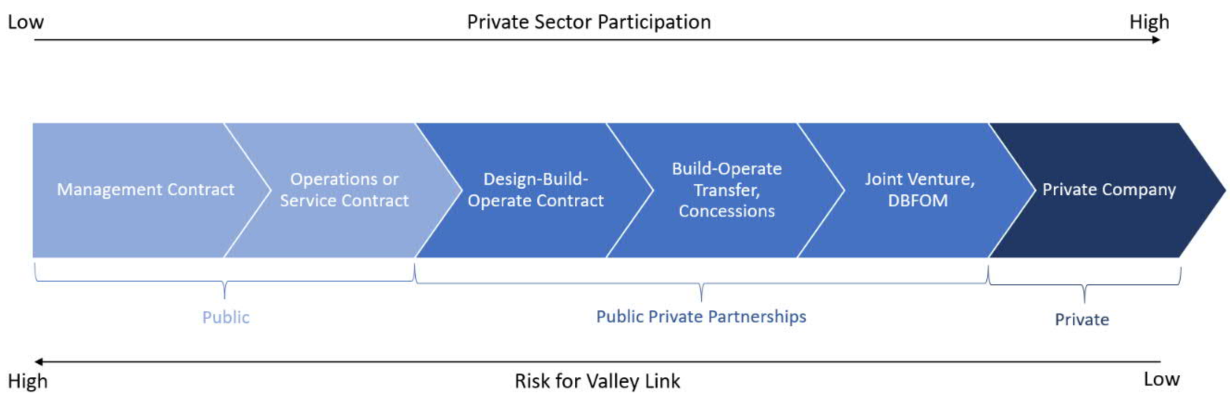


Figure 49: Flowchart of increasing private involvement in public infrastructure projects

7.2.2. Potential P3 Agreements at Valley Link

The P3 agreements that would apply best to the Valley Link production facility include Design-Build (DB), Design-Build-Operate (DBO), Design-Build-Operate-Maintain (DBOM), Design-Build-Finance-Operate (DBFO), Design-Build-Finance-Operate-Maintain (DBFOM). There are also Transfer models that could be considered such as Build-Operate-Transfer (BOT), or Build-Own-Operate-Transfer (BOOT), however it should be further discussed whether it would be beneficial for Valley Link to own and operate the facility sometime in the future. Whether the agreement includes a transfer at the end of the contract or not, there are a number of complexities that arise in an agreement of this scale. To take on the complexities of the agreement and minimize risk for all parties involved, a special purpose vehicle (SPV) or project company is often created for the lifetime of the contract. Not all P3 agreements require the use of an SPV, however, for infrastructure projects that are capital-intensive, private companies often want to limit financial risk by creating an SPV. Figure 50 below represents a public private partnership model for the Valley Link production facility, including the use of an SPV.

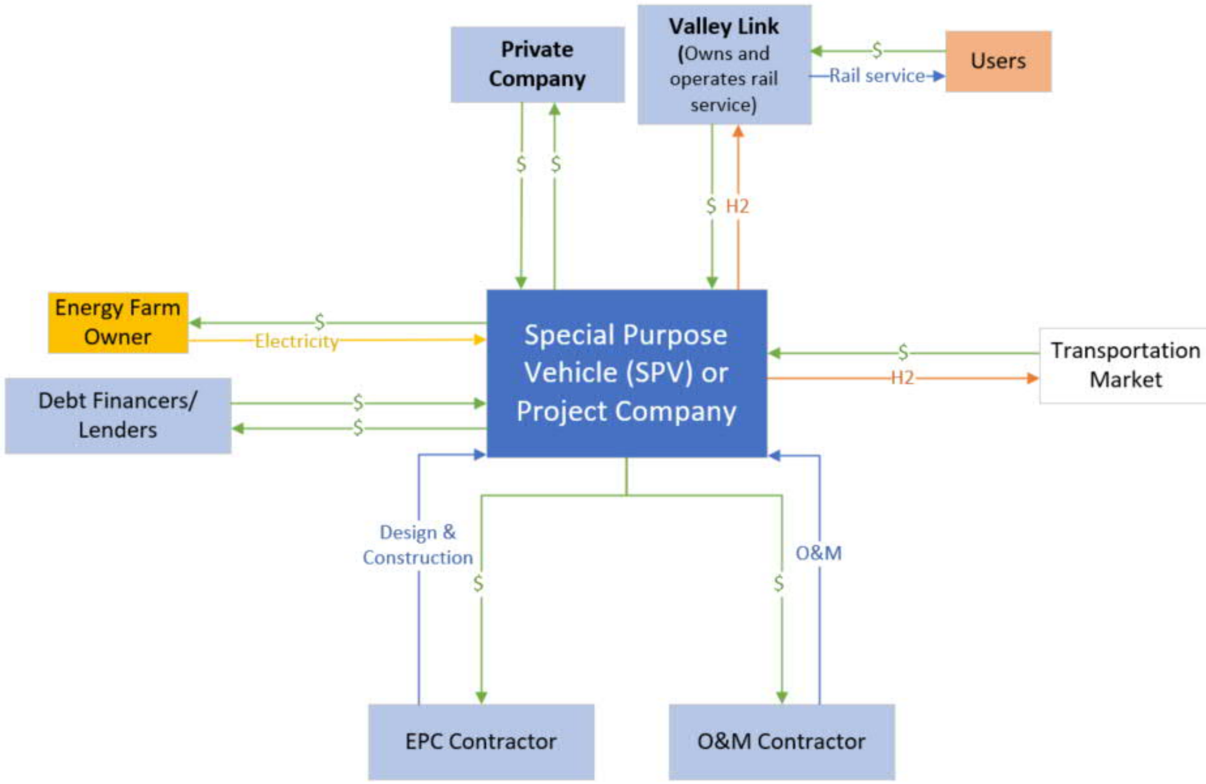


Figure 50: Example of P3 agreement for Valley Link including SPV

7.2.3. Considerations for Valley Link

Most of the examples of P3s in existence today are for public sector infrastructure projects including hospitals, schools, highways, light rail transit, wastewater plants, etc. Although hydrogen production infrastructure for public transit agencies lends itself well to P3s, it is an emerging field and therefore there are no historic examples of successful P3s that would directly apply to Valley Link. It is therefore recommended that the following considerations be evaluated in detail additionally to any traditional P3 considerations.

- Understanding the California Codes of Law and what it has to say about P3s
  - The information included thus far is general in nature and not specific to California
  - It should be noted that the Public Contract Code[47] does allow for design-build projects with a transition period for O&M. This transition period should be temporary in nature and not span many years.
  - It should also be noted that some good guidance documents do exist for P3 agreement development. The League of California Cities has developed a relatively recent

[47] https://leginfo.legislature.ca.gov/faces/codes_displayText.xhtml?lawCode=PCC&division=2.&title=&part=3.&chapter=4.&article=

guidance document dated May 2021[48].

    - This document references Government Code section 5956[49] and states that this section allows Local Agencies to utilize private sector investment capital to study, plan, design, construct, develop, finance, rebuild, improve, repair, or operate, or any combination thereof, "fee-producing infrastructure facilities". 5956.4(c) identifies "Energy or power production" as "fee-producing infrastructure facilities". These qualified fee-producing infrastructure facilities may be procured through a "competitive negotiation process" and "shall not require competitive bidding". Therefore, although the Public Contract Code appears to limit the P3 agreements possible for public agencies, this code allows financing to be brought in from the private sector.

- Higher O&M risk due to lack of experiential data might result in a higher fixed price for hydrogen for Valley Link
- Revenue from excess offtake sales to transportation market may not be included in the P3 or may not impact the fixed price for Valley Link as it would raise the risk profile for the private company

For the most part P3s are used when there is existing commercialized technology available from several competitive companies. For the onsite production facility there is a limited number of electrolyzer technologies available, and the existing technologies have limited experience in the field. Therefore, the private partner may be taking on more risk by designing for O&M when there is little existing data for the O&M required throughout the lifetime of the facility. This may result in that risk being included in a higher fixed hydrogen price to Valley Link.

Similarly, private companies are often interested in P3s due to the guarantees of a captive market. The public partner will often agree on a certain amount of demand or utilization for the entire lifetime of the P3 contract. So, if the private company is going to take on the risk of selling the excess hydrogen to a market that is not yet fully developed, again that risk might be quantified in the fixed price of the hydrogen contract. Alternatively, if the P3 entity obtains higher revenue than was initially assumed based on the risk of the new market, that revenue might not flow back to Valley Link. It will be very important that Valley Link better understand these risks, how a private company may understand them, and make sure that the P3 contract best covers the potential risk for both partners but also allows both partners to benefit from the market opportunity.

7.3. Private Company

If Valley Link does not want to take on the risk of being a partner in the development of the onsite production facility, there is the option for a private company to undertake the project completely and just sell fuel to Valley Link. Valley Link could lease out a parcel of the land at the Tracy OMF facility to a private firm and then enter into an agreement to purchase hydrogen from them at an

[48] https://www.cacities.org/Resources-Documents/Member-Engagement/Professional-Departments/City-Attorneys/Library/2021/21-Spring/5-2021-Spring;-Crawford-Merewitz-Public-Private-Pa.aspx
[49] https://leginfo.legislature.ca.gov/faces/codes_displayText.xhtml?lawCode=GOV&division=6.&title=1.&part=&chapter=14.&article=

agreed upon price. This option would allow Valley Link to take on less of the construction risk, however the agency would not be involved in the design and scale up of the facility, so there would be more risk associated with having enough hydrogen supplied on time, and at a reasonable price. Additionally, due to Valley Link's relationship with the local government and the public scrutiny transit agencies face, leasing the land may not even be an option.

7.4. Funding Opportunities

Whether through traditional procurement methods or through a P3 agreement, Valley Link would need to raise funds either through government loan programs or grants. Government grants would provide the greatest financial contribution to the project by lowering the capital cost of the project. The largest fund available for hydrogen production projects in the US, the $8 billion DOE hubs fund, will be accepting applications in the fall of 2022. The Hubs funding program will provide funding to 6-10 regional hubs across the US. The hubs must include multiple production technologies and multiple end-uses, and will be very large in scale since the focus of the program is to scale-up the hydrogen industry (e.g., ~100 tonnes-H2/day). If Valley Link were to partner with other larger producers in the California central valley for a hub application, they could potentially get some funding to offset the capital costs of the facility.

State assembly bill AB118 created the Clean Transportation Program, which authorizes the Clean Energy Commission (CEC) to develop and deploy alternative and renewable fuels and advanced transportation technologies to help attain the state's climate change and clean air goals. There remains $7 million available in funding for zero- and near-zero-carbon fuel production projects, with an additional $17 million that could be available in the coming years depending on future budget act appropriations.[50]

Valley Link as the entity that is dispensing the fuel, would also qualify for the generation of Low Carbon Fuel Standard (LCFS) credits. The LCFS requires transportation fuel providers to lower the carbon intensity of their fuels by purchasing credits which are equivalent to 1 tonne-CO2e abated. By using clean hydrogen as the fuel for the trains, Valley Link could generate credits and sell them on the market. The historical credit price and total volume of credits exchanged on the market is shown in Figure 51 below. The potential revenue from the LCFS credits per kg-H2 dispensed is included in the financial model described above in section 6.

[50]CEC Staff Workshop. Zero and Near Zero Carbon Fuel Production and Supply Funding Concepts. 5/18/2022. Source: https://efiling.energy.ca.gov/GetDocument.aspx?tn=243123&DocumentContentId=76809

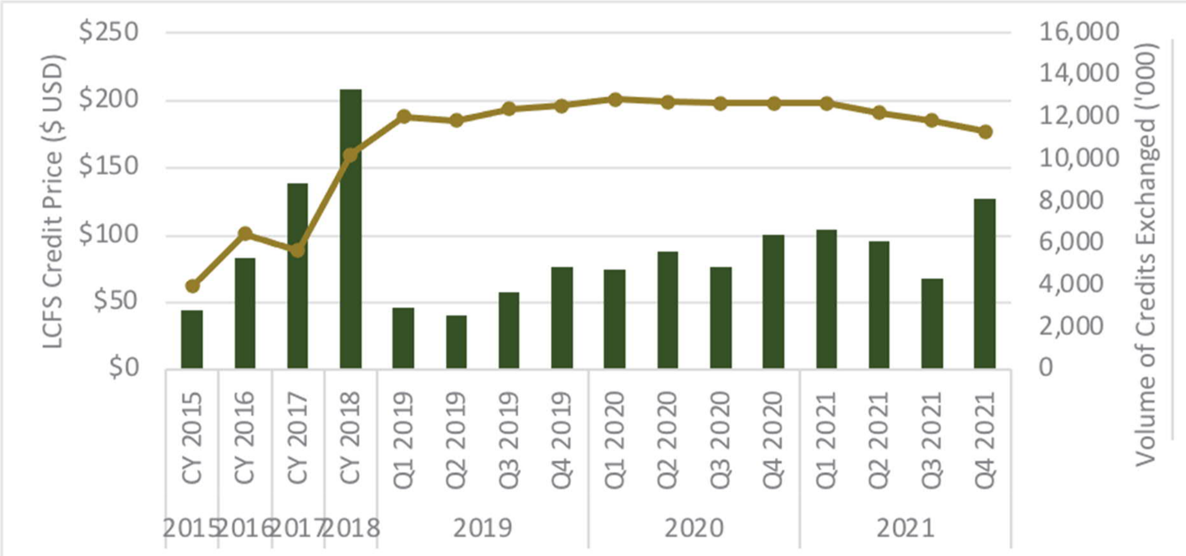


Figure 51: LCFS credit market historical data

Beyond assessing the applicability of the potential funding opportunities mentioned above there are a few strategies to be employed that would expand the total funding opportunity:

- Go after transit funding to offset the cost of the trains and rail infrastructure separately from the hydrogen production facility and dispensing.
- Apply for funding for each phase of the project separately to minimize risk and to improve the cash flow.
- Apply for funding for the solar farm separately from the hydrogen production facility so as to make use of different funding sources.
- During the preparation phase of the project, discuss project with state and county officials to increase visibility of the project and the need for funding allocated through the state or county budgets.

8. RECOMMENDATIONS

In making a recommendation, it is important to consider the project stages and assess in which stage the project is and what decisions must be made to move to the next project stage, which thereby informs the recommendation. The project being structured in three phases sheds some risk as it allows significant learning in the first project phase in addition to market/technology maturation and further partner relationship building. An indicative project schedule was built and is included in the Appendix A. This project schedule is indicative of a project with a design-build-operate-maintain P3 strategy. See below for an outline of the project stages:

- Feasibility
- Planning and Preliminary Design
- Issue RFQ/RFP
- Award/Negotiations
- Development/Design
- Construction
- Operate & Maintain

Currently, the project has completed the feasibility stage. The purpose of this feasibility study was to evaluate the physical and financial feasibility of developing an on-site hydrogen production system at the OMF that is fed by on-site renewable electricity and compare it to purchasing hydrogen from a supplier and dispensing it at the OMF. A key tool in this feasibility study was a financial model that included technical constraints and calculations to understand the operational and financial feasibility.

Given the following considerations: 1) the feasibility study showed the on-site electrolytic hydrogen production facility to be feasible with significant potential for developing positive cash flow to drive down Valley Link rider costs, 2) the significant opportunity from funding announcements related to hydrogen (e.g., IIJA), and 3) the significant private sector and state interest in the onsite electrolytic hydrogen production projects, it is recommended that Valley Link pursue the *onsite electrolytic hydrogen production concept* and move into the Planning and Preliminary Design stage. Figure 52 shows the different activities in the next project stage, which include developing strategies for permitting, water supply, electricity supply, public-private partnership, utility interconnection, and offtake sales agreements. The financial model will also need to be updated during this stage as new information is gathered. The activity on public-private partnership strategy is important since it can reduce risk across the project, therefore, learning more about public-private partnerships and exploring potential partners is key. Figure 52 also shows the key decision gates where Valley Link board will decide on whether to pursue the project further.

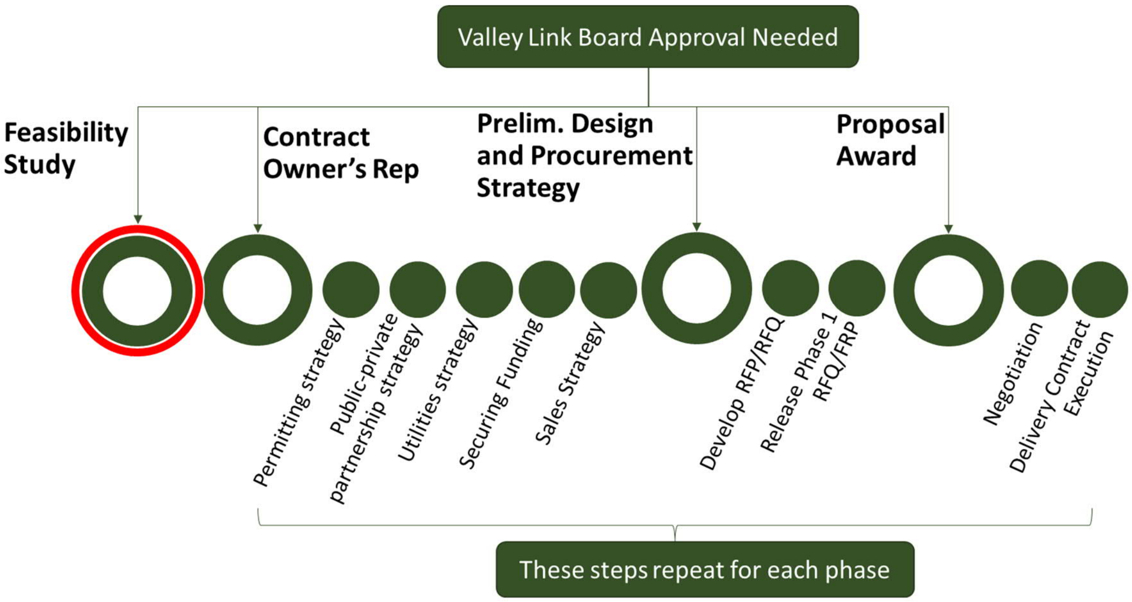


Figure 52: Valley Link board approval gates and the various activities occurring before each gate

The activities required to in the Planning and Preliminary Design stage will require hiring an Owner's Representative[51]. Their scope of work should include:

- Project specification development
- Tailoring of project financial model as new design and cost input updates occur from various stakeholder meetings
- Modeling of solar PV systems and dispatch of BESS for hydrogen production systems to assess changes as the design evolves
- Performance modeling of hydrogen production and dispensing systems to assess changes as the design evolves and ensure that vendor claims are accurate
- Drafting Requests for Information on different project elements
- Working with utilities to understand the interconnection process to their systems (water/electricity)
- Developing hydrogen offtake agreements
- Assistance in RFQ/RFP document development particularly the project performance related language, e.g., performance guarantees such as availability and minimum efficiency requirements
- Due to the complexity of P3s in a new area of infrastructure development, it is recommended that Valley Link and the owner's representative seek special legal counsel on the procurement strategy and contracting.
- Identify funding opportunities and support in writing proposals to secure funding

[51] Per the Public Contract Code, the entity developing the RFQ/RFP documents must be a licensed engineer in California

opportunities

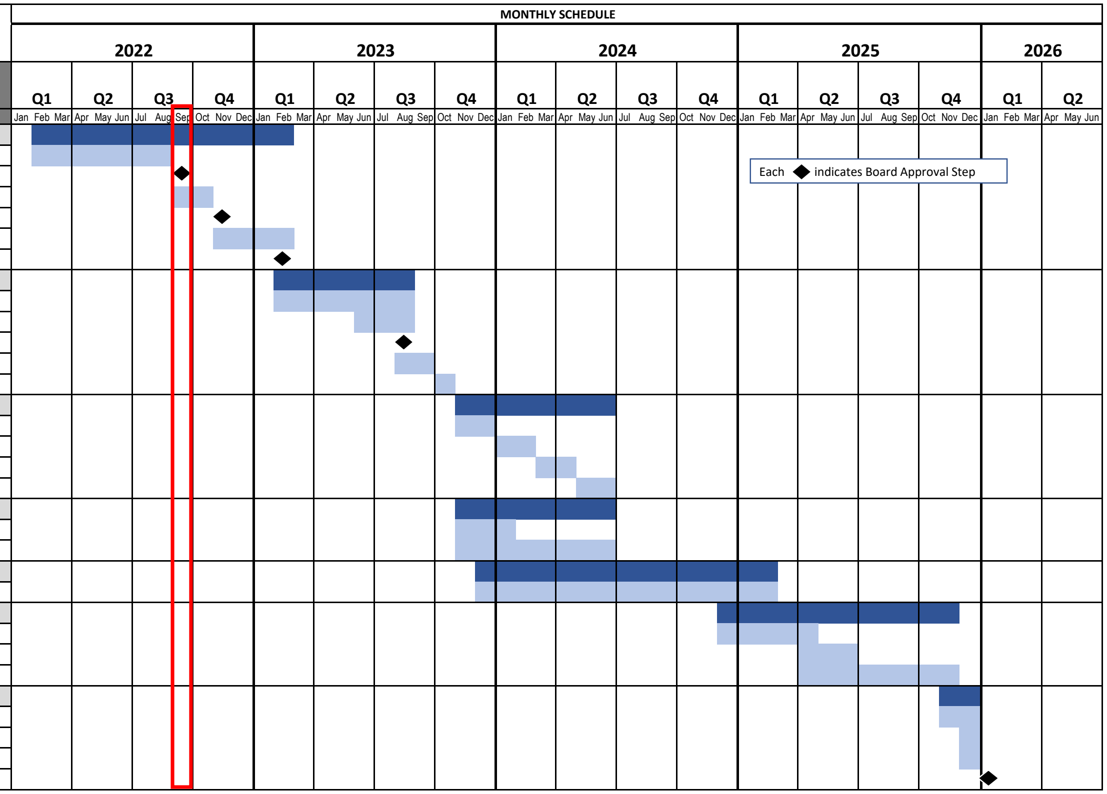
The learnings from Phase 1 will inform similar activities in the scaling-up in Phase 2 and 3. However, with long-lead equipment delivery schedules, the project team should prepare the initial design and business case for all three phases prior to issuing the RFP for Phase 1 and include the scope for Phase 2 and 3 as alternates in the Phase 1 RFP where the proposers are asked to design and price those alternates. Valley Link does not have to select the alternates, but it will provide important feedback to Valley Link from the proposers in seeing how the Phases will fit together.

Figure 53: Rendering of 55 MW solar, a 16 MW electrolyzer, storage tanks and 3 MW of fuel cells.
Source: HDF Energy, https://www.hdf-energy.com/en/references/

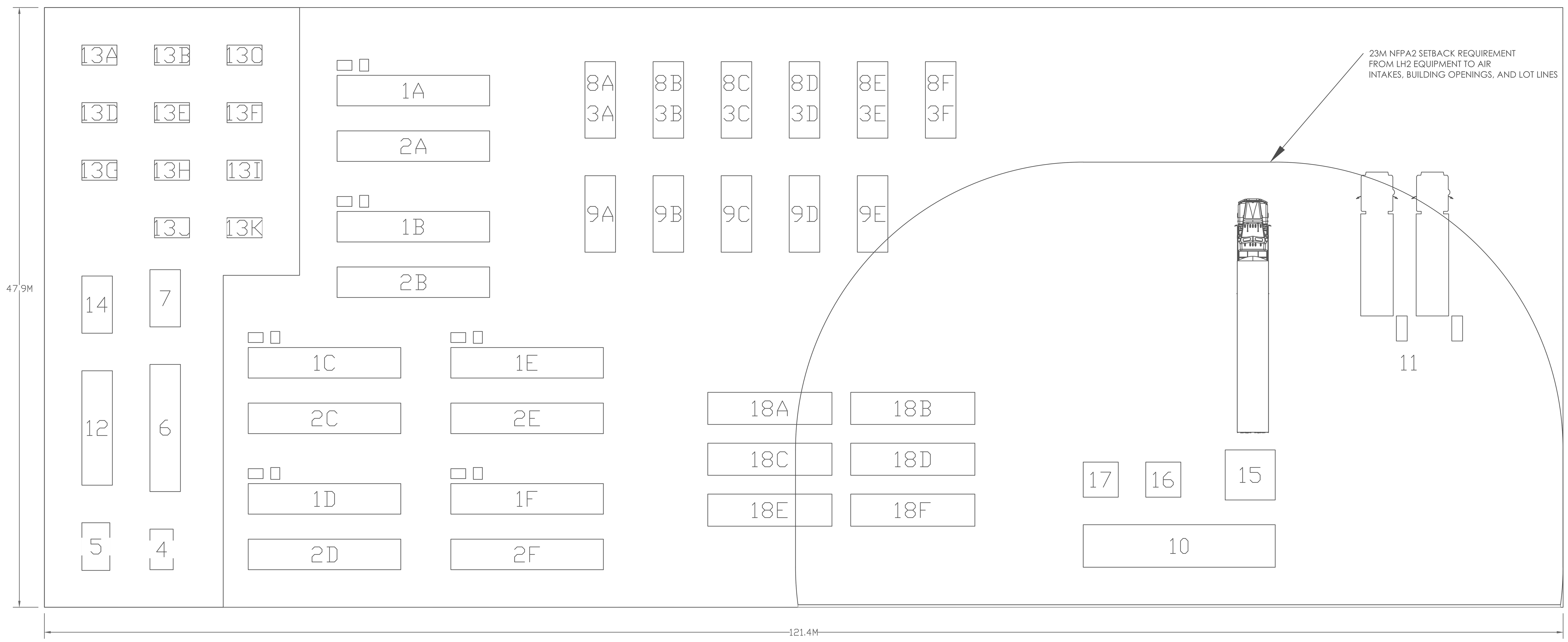
APPENDIX A–PROJECT SCHEDULE EXAMPLE

Phase 1 Schedule - Valley Link Onsite H2 Production Facility

Task Number	Task Name
1	**Preliminary Engineering and Design**
1.1	Feasibility Study
1.2	Board Approval - Feasibility Study
1.3	Owner's Rep RFP and Selection
1.4	Board Approval - Owner's Representative
1.5	Planning and Preliminary Design Activities
1.6	Board Approval - Preliminary Design and P3 Strategy
2	**Procurement**
2.1	Develop RFP/RFQ Documents
2.2	Release RFP
2.3	Board Approval - Proposal Awarded
2.4	Contract Negotiation
2.5	Delivery Contract Execution
3	**Design**
3.1	30 % Design Documents
3.2	60 % Design Documents
3.3	90 % Design Documents
3.4	Final Design
4	**Permitting**
4.1	Prepare/submit permits
4.2	Obtain Approved Permits
5	**Equipment Acquisition**
5.1	Order/Delivery of Long Lead Items (electrolyzer, dispensers)
6	**Construction**
6.1	Site Preparation (civil work)
6.2	Electrical/Mechanical/Utility Prep
6.3	On-Site Equipment Installation
7	**Commissioning**
7.1	Develop Commissioning Plan
7.2	Pre-Startup Safety Review
7.3	Test & Certify
7.4	Board Acceptance of Facility - Phase 1



APPENDIX B–EXAMPLE PROJECT LAYOUTS



LEGEND	
1A-F	OUTDOOR PEM UNIT - GAS PROCESSING CONTAINER
2A-F	OUTDOOR PEM UNIT - POWER & CONTROL CONTAINER
3A-F	30 BAR BUFFER TANK
4	TRANSFORMER
5	SWITCH GEAR
6	LV ELECTRICAL ROOM
7	INSTRUMENT AIR SYSTEM
8A-F	30-500BAR GH2 COMPRESSOR SKIDS
9A-E	500-900BAR GH2 COMPRESSOR SKIDS
10	66,000 L LH2 STORAGE
11	POWERCUBE TRANSFILL BAYS
12	CONTROL ROOM/LUNCH ROOM
13A-K	COMPRESSOR CHILLER
14	GENERATOR
15	LH2 TRANSFILL
16	LH2 PUMP
17	VAPORIZER
18A-F	600 KG STORAGE ARRAYS

5M

25M

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DRAWING TITLE
5TPD PRODUCTION FACILITY
OUTDOOR ELECTROLYSERS
WITH LH2 AND GH2 GROUND STORAGE

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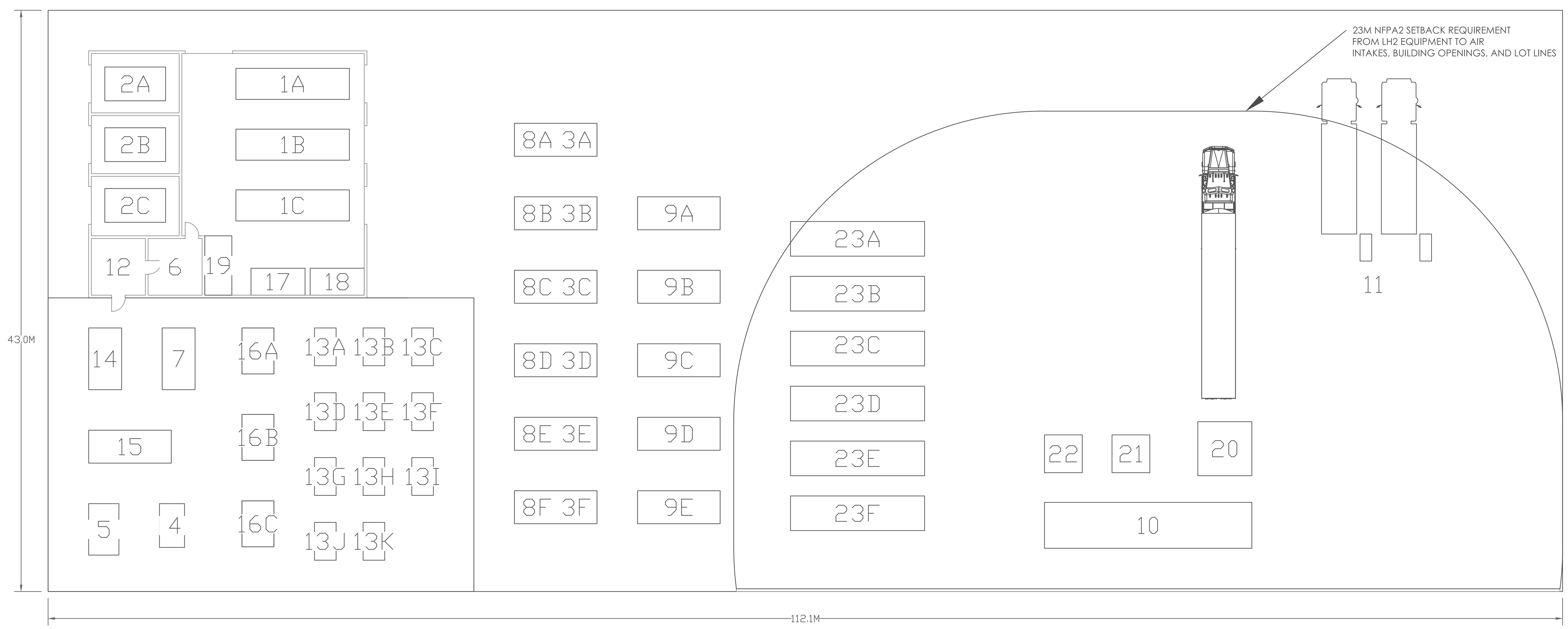

LEGEND	
1A,B,C	INDOOR PEM UNIT
2A,B,C	RECTIFIER
3A-F	30 BAR BUFFER TANK
4	TRANSFORMER
5	SWITCH GEAR
6	LV ELECTRICAL ROOM
7	INSTRUMENT AIR SYSTEM
8A-F	30-500BAR GH2 COMPRESSOR SKIDS
9A-F	500-900BAR GH2 COMPRESSOR SKIDS
10	66,000 L LH2 STORAGE
11	POWERCUBE TRANSFILL BAYS
12	CONTROL ROOM/LUNCH ROOM
13A-K	COMPRESSOR CHILLER
14	GENERATOR
15	THERMAL MANAGEMENT SYSTEM
16A,B,C	COOLING TOWERS OR DRY COOLERS
17	HYDROGEN PURIFICATION SYSTEM
18	WATER TREATMENT
19	RECTIFIER COOLING SKID
20	LH2 TRANSFILL
21	LH2 PUMP
22	VAPORIZER
23A-F	600 KG STORAGE ARRAYS

5M

25M

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HTEC
FUELING THE DRIVE TO HYDROGEN

DRAWING TITLE

5TPD PRODUCTION FACILITY
INDOOR ELECTROLYSERS
WITH LH2 AND GH2 GROUND STORAGE

DRAWING NUMBER	SCALE	SIZE	REVISION
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