Fueling the California Mobility Market with Hydrogen from Natural Gas plus Carbon Capture and Sequestration

Stanford | Natural Gas Initiative
Stanford EARTH | Stanford Center for Carbon Storage

May 2022

About

About the Natural Gas Initiative

Sustainable gas will be a critical component of our clean energy future to provide reliability in a high-renewables world and as a feedstock for low-carbon chemicals and products. The Stanford Natural Gas Initiative is a multi-disciplinary collaboration of more than 40 research groups at Stanford University drawn from engineering, science, policy, geopolitical, and business disciplines that works with a consortium of industry partners and other external stakeholders. Together we strive to generate the knowledge needed to use natural gas to its greatest social and environmental benefit.

About the Stanford Center for Carbon Storage

Carbon Capture, Utilization, and Storage is a key technology for achieving net-zero greenhouse gas emissions. The Stanford Center for Carbon Storage (SCCS) uses a multidisciplinary approach to address critical questions related to flow physics, monitoring, geochemistry, geomechanics and simulation of the transport and fate of CO_2 stored in partially to fully depleted oil & gas fields and saline reservoirs. SCCS is an affiliates program associated with the Stanford University School of Earth, Energy and Environmental Sciences.

***Suggested Citation**: Bracci, J., Okoroafor, E.R., Shrimali, G., Hennessy, E., Kim, T., Biddle Seamon, D., Boness, N.L., Saltzer, S. D., Kovscek, A.R., Benson, S.M., Zoback, M.D., Fueling the California Mobility Market with Hydrogen from Natural Gas plus Carbon Capture and Storage, Stanford Natural Gas Initiative and Stanford Center for Carbon Storage, May 2022.*

Stanford | Natural Gas Initiative

Stanford EARTH | Stanford Center for Carbon Storage

Acronymns

AB	Assembly Bill
ATR	Auto thermal reforming
BAU	Business as usual
BEV	Battery electric vehicle
CAPEX	Capital expenditures
CARB	California Air Resources Board
CCS	Carbon Capture and Sequestration
CI	Carbon intensity
EFI	Energy Future Initiatives
EMFAC	Emission Factor Database
EO	Executive Order
FCEV	Fuel cell electric vehicle
FCFP	California Fuel Cell Partnership
FER	Fuel economy ratio
LCFS	Low Carbon Fuel Standard
LCOH	Levelized cost of hydrogen
MSS	Mobile Source Strategy
NETL	National Energy Technology Laboratory
OPEX	Operating expenditures
SMR-CCS	Steam methane reforming with carbon capture and sequestration
UGS	Underground gas storage site
ZEV	Zero emission vehicle

Table of Contents

Key Findings

- Based on subsurface criteria, community impact analysis, and land ownership status, 7 sites in northern California appear to be feasible prospects for a collocated SMR-CCS new build facility.
- Future hydrogen demand for the mobility markets in California will be dependent on the evolution of state policy and incentives. Our analysis indicates that a facility with 250 metric ton per day capacity would be appropriate to meet the mid demand scenario.
- With existing federal and state incentives (45Q and LCFS), we estimate the levelized cost of blue hydrogen (SMR-CCS) to be $1.79 per kg which is competitive with grey hydrogen.
- The primary barrier to CCS projects in California continues to be the regulatory framework. Further work with key stakeholders including legislators in Sacramento is needed to enhance commercial attributes of CCS projects and public acceptance.

Introduction

California leads the nation and much of the world in policies to mitigate climate change. The state has near-term goals of 40% emissions reductions (relative to a 1990 baseline) and 60% renewable electricity by 2030 (AB 32); it has a long-term target of net zero emissions by 2045 (EO B-55-38). Most recently, in September 2020 Governor Newsom issued EO N-79-20 that requires new passenger cars and trucks to be zero-emission by 2035, and all medium and heavy duty vehicles to be zero-emission by 2045. Although battery electric vehicles currently represent most of the zero emission vehicles (ZEVs) on the road in California, fuel cell electric vehicles offer features including longer range, higher payload, greater cargo volume, and fast refueling.

Shell has been an advocate of using hydrogen to meet the increasing transportation fuel demand in a decarbonizing world [1]. The Shell study concludes that in 2050, 113 million fuel cell electric vehicles could save up to 68 million metric tons of fuel and almost 200 million metric tons of carbon emissions. Currently, Shell has six hydrogen refueling stations in California and is currently working in partnership with Toyota, with the support of the State of California, to build three more plus three heavy duty stations. Further growth in the hydrogen market is expected. Indeed, the California Fuel Cell Partnership (FCFP), of which Shell is a prominent member, has set a vision of 200 hydrogen stations by 2025 and 1000 stations by 2030, pursuant to the Governor's 2018 ZEV infrastructure proposal.

Shell's existing hydrogen refueling stations are supplied with hydrogen generated by Steam Methane Reforming (SMR) of natural gas. The affordability of natural gas makes SMR the most common and economical way to produce hydrogen. The median CO_2 emissions normalized for SMR hydrogen production is 9.3 kg CO_2 per kilogram of net hydrogen produced [2]. If the FCFP vision of 200 stations in California in 2025 is realized at an average dispensing rate of 200 kg H_2 per day, the corresponding emissions would be 136 metric tons of CO_2 per year.

Stanford and the Energy Futures Initiative recently released a joint study "An Action Plan for Carbon Capture and Storage in California: Opportunities, Challenges and Solutions" [2], that identifies over 70 Gt of potential CO_2 storage capacity in the state, and lays out many of the regulatory hurdles, as well as providing recommendations the state can take to achieve scale in CCS.

With sizable federal tax credits (45Q) for captured and sequestered carbon that require projects to begin construction before 2026, it is critical that new CCS projects begin development in the near-term. These tax credits, combined with Low Carbon Fuel Standard incentives (LCFS), offer a strong—and urgent—business case for commercial scale blue hydrogen projects (SMR and CCS) in California.

This report is a comprehensive assessment of the technical and business potential for siting a hydrogen SMR facility with carbon capture and onsite geologic storage in Northern California to supply Shell's hydrogen distribution retail network. The report includes the findings from the following workstreams:

- Workstream 1: Assessment of carbon dioxide storage opportunities in Northern California
- Workstream 2: Evaluation of business and regulatory framework for hydrogen generation with CCS in California.
- Workstream 3: Technoeconomics of hydrogen generation with CCS in California
- Workstream 4: Combined feasibility analysis and recommended path forward

A pre-project scoping analysis was performed prior to the commencement of the workstreams listed above. This scoping analysis was done to determine the region for the project focus – Northern, Central, or Southern California.

Results of pre-project Scoping Analysis

A preliminary scoping analysis was performed to determine the location and preferred SMR new-build size for further study. An assessment of all the oil and gas fields and underground gas storage sites in California was conducted to determine which ones met allowable criteria for CO_2 storage. These results were combined with an assessment of hydrogen demand for the transportation market, infrastructure needs and costs, technoeconomics, and local regulatory/community/ social issues. It was jointly decided by Shell and Stanford that the study would focus on Northern California for further evaluation, based on the results shown in Table 1. Thus, the detailed evaluation presented herein is focused on the northern region of California.

	Bay Area + Sacramento Valley		San Joaquin Valley		South Coast (LA)	
H_2 Demand for Transportation	**2035 H2 Demand** 265 ton/day	**Associated CO_2 captured** 0.871 Mt/year	**2035 H2 Demand** 115 ton/day	**Associated CO_2 captured** 0.378 Mt/year	**2035 H2 Demand** 351 ton/day	**Associated CO_2 captured** 1.153 Mt/year
CO2 Subsurface Storage Options	**O&G/UGS** 27 Sites 442-662 Mt CO_2	**Saline Res** 5 reservoirs 4-12 Gt CO_2	**O&G/UGS** 25 Sites 429-1090 Mt CO_2	**Saline Res** 9 reservoirs 30-86 Gt CO_2	**O&G/UGS** 14 sites 214-400 Mt CO_2	**Saline Res** 2 basins 0.4-5.2 Gt CO_2
Infrastructure Needs and Costs	**Co-located SMR & CCS:** Yes **H_2 transportation:** 75 km **Feedstock gas:** 1002 ton/day **Gas Price:** $0.65 / therm		**Co-located SMR & CCS:** Yes **H_2 transportation:** 100 km **Feedstock gas:** 435 ton/day **Gas Price:** $0.65 / therm		**CO_2 transport cost:** $10/ton **$H_2$ transportation:** 50 km **Feedstock gas:** 1327 ton/day **Gas Price:** $0.69 / therm	
Techno-economics	**LCOH:** $2.04/kg **Without H_2 transport:** $1.26/kg		**LCOH:** $2.49/kg **Without H_2 transport:** $1.55/kg		**LCOH:** $1.77/kg **Without H_2 transport:** $1.16/kg	
Local regulatory/ community/social	**Ozone Non-Attainment** Moderate	**PM2.5 Non-Attainment** Marginal	**Ozone Non-Attainment** Extreme	**PM2.5 Non-Attainment** Moderate	**Ozone Non-Attainment** Extreme	**PM2.5 Non-Attainment** Serious

Table 1: Summary of results of pre-project scoping

Workstream 1: Assessment of CO_2 Storage Opportunities in Northern California

Agreed Scope of Work:

- Literature and data review of all previously published geologic studies for a localized region in California agreed upon in advance with Shell.
- Additional high-grading and scoring of potential storage locations using criteria described above with a focus on depleted gas fields and UGS sites, but with consideration of saline reservoir potential as well.
- Land ownership evaluation for identified sites
- Final site recommendation (which may include more than 1 site) with a detailed site characterization plan for future consideration.

The workflow for the technical assessment of CO_2 storage opportunities in California follows a criteria-driven methodology developed for the geological storage of CO_2 in porous media [3]. The criteria-driven methodology is organized into three stages: site screening, site ranking, and site-specific characterization (Figure 1). The first two stages of the workflow utilize information generally available in public databases, geological surveys, or storage atlases. Additional information, simulations, and data may need to be acquired or performed to select the optimal site during site characterization (stage 3, not part of this study). As

shown in Figure 1 below, the data required at each stage and the complexity of analysis increases while the number of sites evaluated decreases.

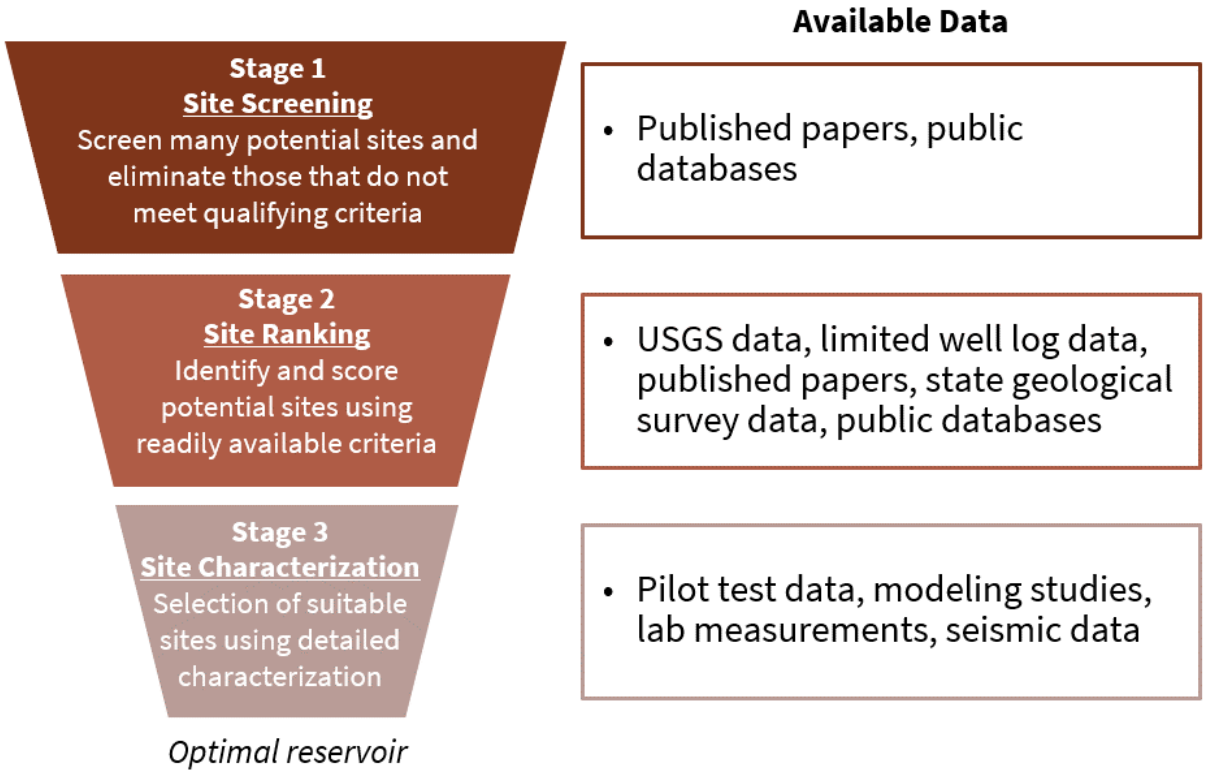

Figure 1: Overview of the site selection workflow designed to select the most suitable site from a pool of potential sites [3]

Stage 1: Site Screening is the first stage in which many potential sites are eliminated if they do not meet a qualifying threshold based on storage capacity, injectivity, geological, economic, and siting considerations. The sites that meet these qualifying criteria move to Stage 2, site ranking.

Stage 2: Site Ranking includes scoring and ranking the sites that met the thresholds in the site-screening stage. Each field received a technical score that combines the capacity and injectivity optimization scores, retention and geomechanical risk minimization criteria scores. The user assigns a weight to each criterion based on the most important parameters for the project. The highest-ranking sites move onto the site characterization stage.

Stage 3: Site Characterization is the final stage where the top-ranking sites from Stage 2 are analyzed in detail to enable the user to determine the most suitable site for CO_2 storage. Additional data may need to be acquired at this stage (e.g., seismic, pilot test data), and computational and experimental studies may need to be performed to characterize each reservoir. Stage 3 analysis was not performed as part of this study.

Previous CO_2 Storage Assessments for California

There have been previous studies aimed at assessing the CO_2 storage potential in California, including some regional studies that have examined sites in Northern California. These studies have investigated oil and gas fields, underground storage sites, as well as saline formations.

A study on the carbon sequestration options for the West Coast states determined that California has outstanding sequestration opportunities due to its large capacity and the potential for value-added benefits from enhanced oil recovery (EOR) and enhanced gas recovery (EGR) [4]. The criteria for screening the basins in California include presence of significant porous and permeable strata, thick and pervasive seals, sufficient sediment thickness to provide critical state pressures for CO_2 injection,and accessibility. In addition, basins overlain by national and state parks and monuments, wilderness areas, Bureau of Indian Affairs-administered lands, and military installations were excluded. Based on their screening approach, ten basins in California were identified with estimated storage capacity of saline formations ranging from about 150 to about 500 Gt of CO_2, the potential CO_2-EOR storage estimated to be 3.4 Gt, and the cumulative production from gas reservoirs suggests a CO2 storage capacity of 1.7 Gt.

In a study on factors impacting geologic carbon sequestration potential in California [5], the authors used Bunker, Millar, and Conway Ranch fields as analogs for most gas fields in the Sacramento Basin to evaluate the impact on compartmentalization on CO_2 storage potential. They showed that compartmentalization could limit potential storage capacity, multiple pool strategies for compartmentalized reservoirs are likely to fall short of meeting the lifetime needs of a typical emissions source, and larger fields within the basin may offer better opportunities for CO_2 storage.

The Energy Futures Initiative and Stanford University [2] conducted a three-stage evaluation to assess the suitability of storage in California based on EPA regulations and CARB CCS project eligibility criteria. Stage 1 eliminated sites that did not meet qualifying criteria established by either the EPA and the LCFS CCS Protocol. In Stage 2, additional geographic information (e.g. faulting, seismicity, sensitive habitats, population density, restricted lands) was used to develop an exclusion layer identifying regions where siting of a CO_2 storage facility is unacceptable. Finally, in Stage 3 the results of Stage 1 and Stage 2 were merged to identify prospective storage locations. Based on this analysis, the combined CO_2 storage potential at saline reservoirs and oil and gas fields in the state of California was estimated to be around 70 Gt.

The evaluations described above focused on the CO_2 storage potential of basins or fields in California. The studies did not rank the basins or fields to determine the best locations for CO_2 storage.

Site screening, scoring and ranking using the criteria-driven approach described in Figure 1 has been applied to assess the oil and gas fields in California as potential CO_2 storage sites [6]. Seven parameters were adopted to score and select technically superior storage sites after sites had successfully passed the screening stage. The seven parameters include CO_2 storage resource, porosity, permeability, reservoir thickness, depth to the top of the

formation, presence of a bottom seal, and geothermal gradient. Results of the scoring were used to rank the sites as high priority, moderate priority, and future priority for study as CO_2 injection sites. Fourteen large prospective sites representing 20 $MtCO_2$/year storage rates were identified near the Sacramento Basin and in Kern County. Specifically, it was determined that 10 storage sites in the southern San Joaquin and Ventura Basins have a combined average storage resource of 806 $MtCO_2$, while In northern California 4 sites (2 depleted gas fields and 2 UGS sites) have a combined average CO_2 storage resource of 218 $MtCO_2$.

The seven scoring parameters do not account for factors that would minimize the loss of CO_2 when stored in the subsurface, the geomechanical risks with CO_2 injection, and other economic and siting constraints that may impede the deployment of a CO_2 storage project. We considered these additional factors in our study, providing a comprehensive, methodological approach to ranking sites suitable for CO_2 storage in Northern California.

Site Screening

The first step was to identify all oil and gas fields potentially suitable for CO_2 storage in California and, subsequently, choose the most suitable region for subsurface storage. Stage 1 of the multi-stage screening criteria was applied on all oil and gas and underground gas storage fields in California [3].

Stage 1 consists of three steps. In the first step, sites that qualify for CO_2 storage are identified by comparing field characteristics to “disallowed” conditions. Next, in step 2, areas where CO_2 should not be stored are identified and put into an ‘exclusion zone’. Criteria for the exclusion zone includes potential for faulting and seismicity, population density, sensitive habitats and restricted lands. In the third step, the potential areas for CO_2 storage are assessed by removing the excluded zone from the fields that qualify for CO_2 storage. Details of the Stage 1 screening can be found in [6]. The criteria used in stage 1 are presented in Table 2.

To screen and quantify each field, geological properties, geological structure, and risk-induced data was gathered from existing references and public data. The California Department of Conservation (CA DOC)) has published geological properties (such as porosity and permeability), reservoir conditions (pressure and temperature), structure, operation history, and salinity for each oil and gas field in the state [7]. Information on California’s quaternary faults in Geographic Information System (GIS) format was determined from the United States Geological Survery (USGS) database [8]. For underground gas storage (UGS) fields, the California Council on Science and Technology (CCST) recently reported and summarized properties for underground structures [9]. The estimated CO_2 storage capacity in oil and gas fields was taken from National Energy Technology Laboratory (NETL) National Carbon Sequestration Database (NATCARB) [10]. CA DOC also has publicly available information on wells that traverse the potential sites, including well logs, production history, injection history, areal location, and permitting documentation to understand the current status of each field and the last recorded reservoir conditions. This information in available in the WELLSTAR database [11].

All 516 fields in 4 different districts (Northern, Inland, Coastal, and Southern), were evaluated using the Stage 1 screening criteria. This resulted in 66 sites across California, as noted in Table 1.

Category	Criteria	Disqualifying Threshold
Capacity and Injection Optimization	Depth of top of formation	<800m
	Permeability	<10 mD
	Porosity	<10%
	Reservoir thickness	<10 m
Retention and Geomechanical Risk Minimization	Secondary confining units	No secondary confining unit
	Top seal thickness	<10m
	Active/inactive faulting	Faults active in the Quaternary distance to pressure front: <2km
	Earthquake record	M ≥ 3 (epicenter< 10 km) & M < 3 (epicenter <5km) to pressure front
	Bottom seal/potential for pressure transmission to the basement	No bottom seal
	Production from a reservoir below the storage interval	Yes
Siting and Economic Constraints	Sensitive habitats for depleted fields that are inactive	Critical wildlife habitat for certain species and wilderness study areas
	Population density for depleted fields are that are inactive	> 75 people per km^2
	Restricted lands for depleted fields that are inactive	National landmarks, conservation lands, military installments, American Indian Lands, Federal Lands and State Lands

Table 2: Stage 1 screening criteria

Combining the results of stage 1 with other criteria including hydrogen demand for the transportation market, infrastructure needs and costs, technoeconomics, and local regulatory/community/ social issues with the CO_2 subsurface storage technical feasibility, a decision was made to focus on Northern California for further evaluation. Northern California has 25 oil and gas fields and 2 underground storage sites which passed the Stage 1 selection criteria.

Subsurface Site Ranking

The methodology for the Stage 2 site ranking is shown in Figure 2. Starting with the sites that qualified from Stage 1, the following criteria were ranked in Stage 2: CO_2 capacity optimization, injection optimization, CO_2 loss minimization, and geomechanical risk minimization.

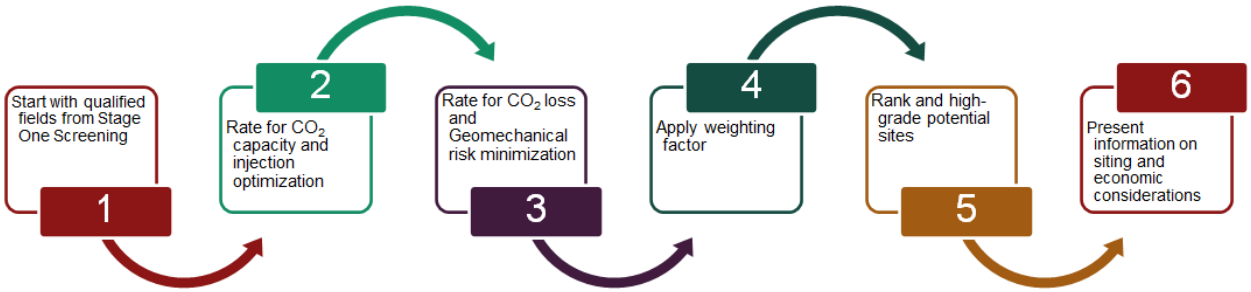

Figure 2: Methodology for Stage 2 site ranking.

Capacity and Injection Optimization

The capacity and injection optimization criteria from [3], presented in Table 3, were applied to all 27 sites in Northern California that passed Stage 1 screening. All five criteria, i.e., **compartmentalization**, **depth of top of formation**, **size** (storage capacity), **permeability**, and **porosity**, were evaluated. Degree of **compartmentalization** was deduced from the maps for Northern California [7].

Criteria	1 (worst)	2	3	4	5 (best)
Compartment-alization	Numerous small (<10% the size of the project) compartments with separate pressure regions	5-10 potential compartments	3-5 Potential compartments	2-3 Potential or confirmed compartments	No compartments
Depth of Top of Formation	800-1000m	Deep (>3,000 m)	2,000-3,000m	1,000-2,000m	
Size (Storage Capacity)	20 MT	50 MT	100 MT	200 MT	≥300 MT
Permeability	10-20 mD	20-50 mD	50-100 mD	100-500 mD	>500 mD
Porosity	10-15%	15-20%	20-25%	>25%	

Table 3: Stage 2 – Site ranking criteria for CO_2 storage and injection optimization.

Retention and Geomechanical Risk Minimization

We scored ten of eleven criteria in this category. Information on **top seal capillary entry pressure** was not available. However, it is assumed that the top seals would minimize entry of CO_2 because they held back natural gas (in the depleted gas fields) for many years.

Criteria	1 (worst)	2	3	4	5 (best)
Top Seal Capillary Entry Pressure (MICP-Threshold Pressure)	P_{entry} (<20 bars)	P_{entry} (20-50 bars)	P_{entry} (50-100 bars)	P_{entry} (>100 bars)	
Stacked Reservoir/ Seal Pairs	1		2		3+
Trap Style	Fault dependent trap (normal)		Stratigraphic, Rollover anticline into growth fault, faulted anticline		Double-plunging anticline (dome)
Degree of Faulting	Extensively faulted		Moderately faulted		Limited faulting
Presence of Quaternary Faults at Reservoir Depth	<2 km from closest injection well		< 5 km from closest injection well		>10 km from closest injection well
Density of Existing/Abandoned Wells	>8 wells/km^2	6-7 wells/km^2	4-5 wells/km^2	2-3 wells/km^2	<1 well/km^2
Age of Existing/Abandoned Wells	>40 years		10-40 years		<10 years
Previous Resource in Reservoir	Depleted oil		Depleted oil + gas reservoir		Depleted gas reservoir
Max plume pressure resulting on caprock (as best can be determined from existing data)	0.9x caprock fracture pressure		0.8x caprock fracture pressure		< 0.8x caprock fracture pressure
Reservoir Current Pressure	Close to initial reservoir pressure or severely depleted below the critical pressure (7.3MPa)				Sufficiently depleted that can accommodate injected CO_2 below the initial pressure
CO_2 Density	<300 kg/m^3	300-500 kg/m^3	500-700 kg/m^3	>700 kg/m^3	

Table 4: Stage 2 – Site ranking criteria for CO_2 loss and geomechanical risk minimization.

stacked reservoir/ seal pairs, **trap style**, and **degree of faulting** were determined from the geological cross-section available for all fields [7]. **Presence of Quaternary faults at reservoir depth** was assessed by extrapolating from the top of the reservoir where there were known quaternary faults to the reservoir depth, along the dip of the fault. If there was a fault at the reservoir depth where a quaternary fault existed on the surface, we considered the fault at the reservoir depth to also be a quaternary fault.

We computed the **density of existing/abandoned wells** by dividing the number of wells from the WELLSTAR database [11] by the area of the field from NATCARB [10]. We estimated the **age of the existing/abandoned wells** as the difference between the current year and the year of the oldest set of wells in each field.

In all cases the **previous resource in the reservoir** was assumed to be gas.

We used Theis' solution [12] to estimate the **maximum plume pressure resulting on caprock.**That is, the pressure at the point of CO_2 injection in the well. Next, we used the **CO_2 density (**estimated from the NIST database at the reservoir's current pressure and temperature [13]) to calculate the resulting pressure on the caprock from the point of CO_2 injection. We then compared the pressure on the caprock to the fracture pressure in order to assess the proper score for each field. We deduced the fracture pressure from leakoff tests in WELLSTAR for some sites. In the absence of leakoff tests, we estimated the fracture pressure as the minimum horizontal stress for each field [14], using an overburden gradient of 23 Mpa/km.

Reservoir current pressure was obtained from permits contained in the WELLSTAR database [11]. We acknowledge that some of the pressures might not be current, as measurements in the database are the last reported values. Reservoirs that are aquifer supported can return to near initial pressure just a few years after production stops. We assume that all sites had pressures that were depleted relative to initial pressure, and did not eliminate any sites based on this criterion.

Applying Weighting Factor

We used a paired comparison matrix to assign relative weighting for each criterion. The matrix is shown in Table 5. We assigned a score between 2 and 4 to compare any two criteria. A score of 2 indicates that the row criterion is less important than the criterion in the column. A score of 3 indicates equal importance between the two criteria. A score of 4 indicates that the criterion in the row has more importance than the criterion in the column. We calculated the total weight from each row's sum. We ranked each parameter and then assigned weightings of 1.75, 1.5, 1.25, and 1.0 for different groups of criteria as shown in Table 6. We then applied the weighting factor to the ratings for the CO_2 capacity and injection optimization, and CO_2 loss and geomechanical risk minimization.

	Criteria	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
Capacity and Injection Optimization	A. Compartmentalization		4	4	4	4	2	4	2	2	4	2	2	2	2	2
	B. Depth of top of formation	2		2	2	2	2	2	2	2	2	2	2	2	2	2
	C. Size (storage capacity)	2	4		4	4	2	2	2	2	2	2	2	2	2	2
	D. Permeability	2	4	2		2	2	2	2	2	2	2	2	2	2	2
	E. Porosity	2	4	2	4		2	2	2	2	2	2	2	2	2	2
Retention and Geomechanical Risk Minimization	F. Stacked reservoir / seal pairs	4	4	4	4	4		4	4	2	4	2	4	2	4	4
	G. Trap style	2	4	4	4	4	2		2	2	2	2	2	2	2	2
	H. Degree of faulting	4	4	4	4	4	2	4		2	2	2	2	2	2	2
	I. Presence of Quaternary faults at depth	4	4	4	4	4	4	4	4		4	4	4	4	4	4
	J. Density of existing/abandoned wells	2	4	4	4	4	2	4	4	2		2	4	4	4	4
	K. Aged of existing / abandoned wells	4	4	4	4	4	4	4	4	2	4		4	4	4	4
	L. Previous resource in reservoir	4	4	4	4	4	2	4	4	2	2	2		4	2	2
	M. Max plume pressure resulting on caprock	4	4	4	4	4	4	4	4	2	2	2	2		2	2
	N. Reservoir current pressure	4	4	4	4	4	2	4	4	2	2	2	4	4		2
	O. Top seal capillary entry pressure	4	4	4	4	4	2	4	4	2	2	2	4	4	4	

Table 5: Technical score paired comparison weighting matrix. A two means the row criterion is less important than the column criterion. A three means both criteria are equally important and a four means the row criterion is more important than the column criteria. Letters in top row correspond to criteria in second column.

Subsurface Ranking and High-Grading of Potential Sites

We determined the weighted technical score for each site as the product of the weighting factor (from Table 6) and the score for each parameter (as determined from Table 4). We computed the weighted ***total*** subsurface score, i.e., the sum of the weighted technical score for each site for the categories: **Capacity and Injection Optimization** and **Retention and Geomechanical Risk Minimization**. The weighted total subsurface score for each site ranged from 80.25 to 107.25. We then ranked the fields from 1 to 27 in descending order based on their weighted total score. The results are shown in Table 7. We also graded the fields into high, medium, and low to guide how to prioritize Stage 3 site characterization.
In Figure 3, we show the high-graded fields and their storage capacities. Once the minimum CO_2 storage space is determined, it can be used to further eliminate sites that do not meet that criterion. Figure 4 shows where the fields are located in map view.

Criteria	Total weight	Weighting
Presence of Quaternary faults at reservoir depth	72	1.75
Age of existing / abandoned wells	70	1.75
Stacked reservoir / seal pairs	66	1.75
Density of existing / abandoned oil and gas wells	64	1.75
Top seal capillary entry pressure	61	1.75
Max plume pressure on caprock	60	1.50
Previous resource in reservoir	58	1.50
Degree of faulting	56	1.50
Reservoir current pressure	56	1.50
Compartmentalization	54	1.25
Trap style	50	1.25
Size (storage capacity)	48	1.25
Porosity	47	1.25
Permeability	45	1.25
Depth of top of formation	39	1.00
CO2 density	N/A	1.00

Table 6: Weightings for individual criteria.

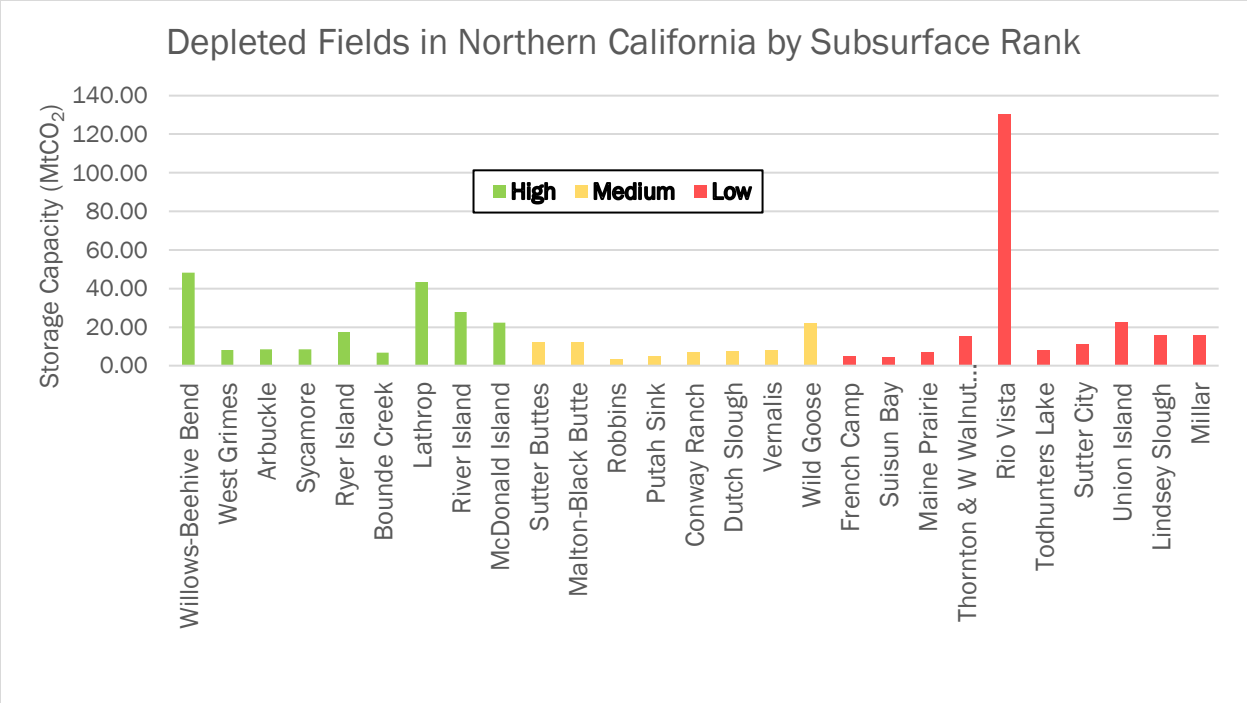

Figure 3: High-graded fields in Northern California and their storage capacities.

Figure 4: Map of the 27 fields evaluated in this study, color coded by rank.

Field Name	Type	Weighted Subsurface Score	Subsurface Ranking (Weighted)	Subsurface Rank
Willows-Beehive Bend	OG field	108.50	1	High
West Grimes	OG field	107.25	2	High
Arbuckle	OG field	107.00	3	High
Sycamore	OG field	106.75	4	High
Ryer Island	OG field	105.00	5	High
Bounde Creek	OG field	104.75	6	High
Lathrop	OG field	102.50	7	High
River Island	OG field	100.25	8	High
McDonald Island	UGS	100.00	9	High
Sutter Buttes	OG field	99.25	10	Medium
Malton-Black Butte	OG field	99.00	11	Medium
Robbins	OG field	98.50	12	Medium
Putah Sink	OG field	98.25	13	Medium
Conway Ranch	OG field	97.00	14	Medium
Dutch Slough	OG field	96.50	15	Medium
Vernalis	OG field	96.25	16	Medium
Wild Goose	UGS	94.00	17	Medium
French Camp	OG field	93.75	18	Low
Suisun Bay	OG field	93.50	19	Low
Maine Prairie	OG field	91.75	20	Low
Thornton & W.-Walnut Grove	OG field	88.25	21	Low
Rio Vista	OG field	87.75	22	Low
Todhunters Lake	OG field	85.75	23	Low
Sutter City	OG field	84.00	24	Low
Union Island	OG field	83.75	25	Low
Lindsey Slough	OG field	83.25	26	Low
Millar	OG field	80.25	27	Low

Table 7: Ranking of fields in Northern California for CO_2 storage.

Summary of Subsurface Site Ranking Findings

Based on this analysis, the top-ranking fields had one or more of the following characteristics:-

- far from known quaternary faults
- few or no separate compartments

- sufficiently depleted from the initial pressure yet having a current reservoir pressure above 7.38 MPa.

The current reservoir pressure is a crucial parameter for the assessment as it could change the eligibility of some fields for CO_2 storage, or change the rating of the field based on density and maximum plume pressure on the caprock. We recommend that prior to Stage 3 reservoir characterization and site selection, there should be confirmation of the current reservoir pressure from dynamic models or estimates obtained from wellhead pressures or bottomhole pressure surveys (if they exist in company databases). In the absence of these sources of data, formation pressure acquisition should be prioritized for Stage 3.

Surface Site Evaluation

Based on available information, we also evaluated the fields for potential community impacts (air quality and community vulnerability/environmental justice concerns) and performed an assessment of land ownership.

In order for this project to be successful, it is essential that the hydrogen production facility is placed in a location where it will not burden already-burdened communities, or cause damage to the local community. To assess this, we use two metrics: air quality, measured as increased exposure to PM2.5, and community vulnerability, measured using a variety of metrics from CalEnviroscreen [15]. An assessment of land ownership was also performed.

Air Quality Impacts

While using hydrogen to power vehicles reduces tailpipe emissions, the SMR facilities used to produce the hydrogen emit both criteria pollutants and greenhouse gases [16]. While carbon capture significantly reduces the greenhouse gas emissions, it does not solve the criteria pollutant emissions. To assess the potential air quality issues associated with hydrogen production, we performed an air quality analysis for the placement of an SMR facility in each potential site.

To assess the air quality impacts of operating an SMR facility in each potential site, we use InMAP [17], a reduced complexity air quality model, and the InMAP Source Receptor Matrix (ISRM) [18] to determine the expected increase in annual average fine particulate matter (PM2.5) concentrations caused by the facility. We then multiply the increase in PM2.5 concentration in each grid cell by the population in each grid cell to determine the increase in exposure, measured as ug-people/m^3. The total increase in exposure is the sum of the increased exposure in each grid cell. Given the lack of data on the impacts of carbon capture technology on criteria pollutant emissions from SMR facilities, we assume emissions are the same as they would be without capture. Table 8 shows the increase in PM2.5 exposure caused by placing the facility at each potential site. Sites with the lowest exposure increase are located further north, in areas with lower population density. Conversely, sites with the highest exposure increase are in areas with larger populations and closer to urban centers.

Community Vulnerability/Environmental Justice

To assess the environmental justice impacts of locating the SMR facility in each potential site, the CalEnviroscreen tool was used. CalEnviroscreen is a tool to measure environmental health and vulnerability to pollution. Four categories of indicators were considered in this analysis: Health Burden; Pollution Burden; Racial Composition; and the overall Enviroscreen score. To complete this analysis, the U.S. Census Tract that each potential site was located in was identified using a spatial overlay, and the characteristics of the census tracts were appended to the sites. The sites were then ranked from least favorable to most favorable according to each metric.

Health Burden

Since increased exposure to pollutants such as ozone and PM2.5 are associated with increased adverse health impacts, there is potential for existing health problems in communities in the surrounding locations to be exacerbated. As such, it would be unfavorable to site the facility in a location that already has significant health issues. CalEnviroscreen includes two health metrics that could be impacted by an increase in air pollutants: asthma incidence; and cardiovascular disease incidence.

Table 8 shows the sites ranked by the **percentile of asthma events** in the census tract they are located in. Two sites fall within the top 10 percentile: Ryer Island and Suisun Bay, suggesting that these two sites may not be suitable. Table 8 also shows the sites ranked by the **percentile of cardiovascular events** in the census tract they are located in. One site falls within the top 10 percentile: Wild Goose, suggesting that it may not be suitable.

Pollution Burden

Since operation of the SMR facility would be expected to increase exposure to air pollutants such as PM2.5 and ozone, it is essential that the facility is not sited in a location that already has high levels of these pollutants. To assess this potential problem, the sites were ranked by PM2.5 pollution percentile and pollution burden percentile.

Table 8 shows the sites ranked by **PM2.5 level**. All sites are located in tracts in census tracts below the 55th percentile for PM2.5 pollution. This suggests that this all sites are acceptable from this perspective.

Table 8 also shows the sites ranked by **pollution burden**. Three sites are located in census tracts in the top 10th percentile for pollution burden: Millar, Maine Prairie, and French Camp. Based on this metric, all three of these sites would be unfavorable.

Racial Composition

Numerous studies have demonstrated that people of color have historically been, and continue to be, exposed to higher levels of pollution [19], [20]. In addition to avoid placing an additional burden on these communities, site locations with large nonwhite populations should be avoided. Table 8 shows the proposed sites ranked by the **nonwhite population** percentage in the census tract in which the potential site is located. We highlighted in color orange sites with percentage of non-whites greater than 50% as possible sites that may be of concern. By this metric, there are 13 sites that are possible areas for concern.

Poverty Index

It is also assumed that the local community and/or environmental justice community will provide strong resistance if an SMR-CCS project is sited in a location with high poverty index. The poverty index is the percent of the population living below two times the federal poverty level (based on a 5-year estimate, from 2015-2019). Table 8 shows the **poverty index** at each of the sites. The smaller the poverty index, the more preferred that site will be for CO_2 storage and siting the SMR-CCS project. We flag sites with more than 50% of the population living below two times the federal poverty level. By this metric, there are three sites (Lathrop Gas; McDonald Island Gas; and Union Island Gas) that may not be suitable for collocating the SMR with CCS.

Cal Enviroscreen Score

In addition to looking at individual metrics, the overall Cal Enviroscreen rating was considered. This metric incorporates income, health, pollution, and other sociodemographic and environmental factors. Table 8 shows the sites ranked in order of the **Cal Enviroscreen percentile**, where a higher percentile indicates a more vulnerable community. Four potential sites are located in census tracts in the top 10 percentile: McDonald Island Gas; Lathrop Gas; Union Island Gas; and French Camp Gas.

Field Name	Exposure (ug-persons/m3)	Asthma Incidence %	Cardio-Vascular %	PM 2.5 %	Pollution Burden %	Non-White %	Poverty Index %	Cal Enviroscreen %	Site with high potential for Health, Environmental, and Community Impact
Willows-Beehive Bend	2.8	21.4	59.5	15.0	38.7	27.4	32.1	25.9	
West Grimes	5.2	45.4	22.7	11.5	66.0	68.4	31.5	64.8	
Arbuckle	5.2	45.4	77.8	11.5	66.0	68.4	31.5	64.8	
Sycamore	5.2	45.4	77.8	11.5	66.0	68.4	37.5	64.8	
Ryer Island	9.5	95.5	88.0	16.1	73.8	71.9	23.3	66.8	Flagged
Bounde Creek	3.0	21.4	59.5	15.0	38.7	27.4	32.1	25.9	
Lathrop	11.4	65.2	48.2	46.3	88.2	71.0	56.5	93.5	Flagged
River Island	8.3	45.2	53.1	25.1	83.8	58.7	43.1	63.7	
McDonald Island	12.9	65.2	48.2	46.3	88.2	71.0	56.5	93.5	Flagged
Sutter Buttes	3.7	22.4	80.7	23.5	34.9	24.6	12.3	37.6	
Malton-Black Butte	2.3	47.7	55.8	8.9	50.7	41.3	36.4	41.6	
Robbins	5.6	81.1	52.2	20.2	78.8	45.8	39.0	61.6	
Putah Sink	18.6	29.1	46.6	18.8	64.1	37.2	17.4	24.5	
Conway Ranch	12.4	60.1	70.0	23.9	68.0	49.5	17.4	54.9	
Dutch Slough	9.9	78.9	79.5	24.9	41.3	65.3	26.0	47.2	
Vernalis	8.2	24.4	27.9	46.0	67.4	60.8	30.0	54.8	
Wild Goose	3.7	73.4	98.0	34.5	43.5	41.3	35.1	61.9	Flagged
French Camp	16.7	83.5	89.5	53.7	98.9	82.3	47.1	99.2	Flagged
Suisun Bay	7.9	95.5	88.0	16.1	73.8	71.9	23.3	66.8	
Maine Prairie	10.4	57.3	44.1	17.2	91.8	46.0	16.8	54.7	Flagged
Thornton & W.-Walnut Grove	8.3	45.2	53.1	25.1	83.8	58.7	43.1	63.7	
Rio Vista	8.2	49.1	68.3	20.3	56.3	27.0	38.1	57.1	
Todhunters Lake	18.6	17.5	22.7	26.9	77.0	45.1	21.7	35.4	
Sutter City	3.7	22.4	80.7	23.5	34.9	24.6	12.3	37.6	
Union Island	10.5	65.2	48.2	46.3	88.2	71.0	56.5	93.5	Flagged
Lindsey Slough	8.2	85.8	84.6	16.6	74.5	35.7	27.2	77.8	
Millar	10.4	57.3	44.1	17.2	91.8	46.0	16.8	54.7	Flagged

Table 8: Community impact assessment table. Red indicates fields of concern for a particular criterion.

Summary of Air Quality and Community Vulnerability Findings

To ensure community acceptance of this project, the facility should be located in a site that will not result in a large increase in exposure to $PM_{2.5}$, and that does not have large, vulnerable populations. Figure 5 shows the potential sites colored by the increased exposure the facility would cause, and the overall CalEnviroscreen Percentile. Overall, the sites that best meet the criteria discussed above are located in the Northern part of the region, near Yuba City and further North.

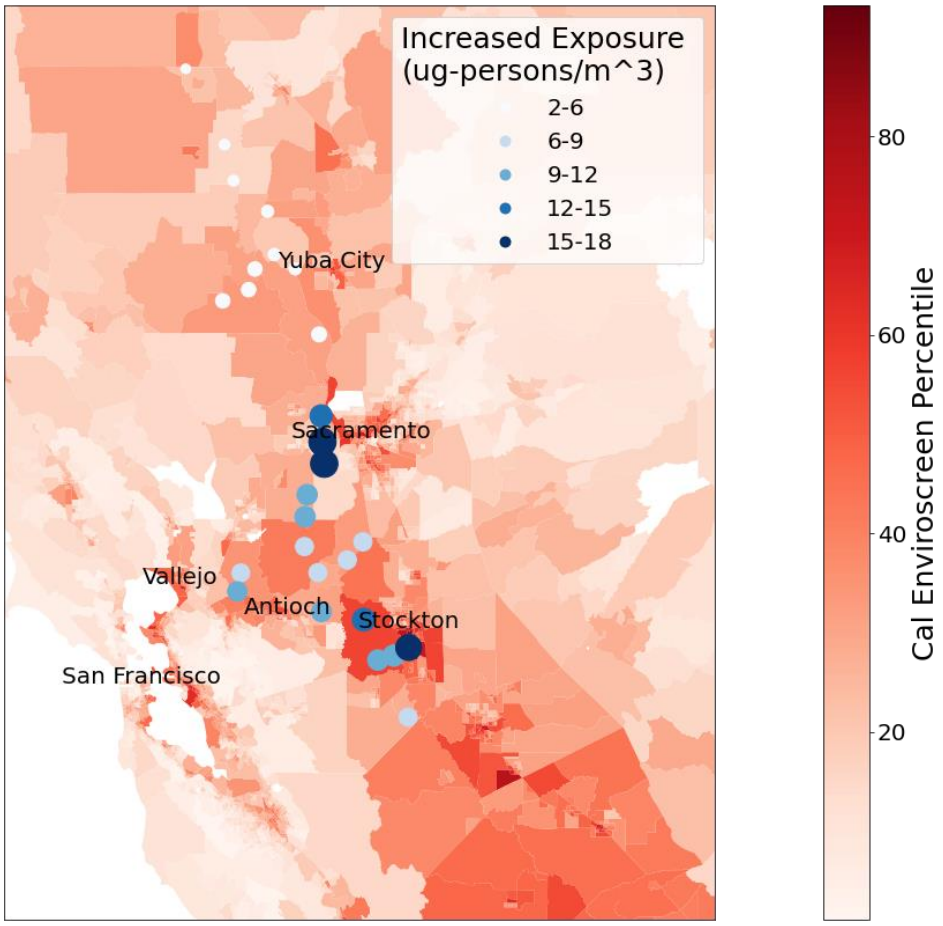

Figure 5: Map of potential sites. Sites are color coded by potential increased exposure caused by a hydrogen SMR facility.

Land Ownership and Location Evaluation

Using ParcelQuest (an online database of landownership in California) [21], we were able to obtain information on landownership above each of the fields evaluated in this study. Table 9 shows the criteria we used to evaluate the land ownership and suitability of the location for SMR.

Criteria	1 (worst)	2	3	4	5 (best)
% Land Area for Agriculture/Agricultural Preserve	0-20	21-40	41-60	61-80	80-100
Parcel Density for agriculture (#parcels/ acre)	>300		100-300		0-100
Distance to nearest major highway (km)	>20		11-20		0-10

Table 9: Criteria for scoring land ownership and location suitability.

Table 10 shows the percentage of the surface land above a given site that is used for agriculture/agricultural preserves, or is owned by the Government. We also provide the parcel density for agriculture, i.e., the number of parcels over the given land area in acres. It is assumed that fields in agricultural areas (higher % land for agricultural or % land owned by government) with fewer landowners (lower parcel density for agriculture) might have fewer surface issues associated with siting a new build H_2 SMR with CCS. Distance to the nearest major highway is also a parameter of interest as the hydrgeon will need to be transported to a filling station along major trucking routes. Applying the criteria in Table 9 to the data in Table 10 gives a total land-type score that ranges from 3 to a maximum of 15. Sites with a land-type score between 3 to 7 are low ranking and flagged as red, sites with a land-type score between 8 and 11 are medium ranking and colored yellow, while sites with a land-type score greater than 11 rank high and are colored green on the land type score column of Table 10.

Field Name	% Land for Agriculture /Agriculture Preserve	% Land Government	Parcel Density for Agriculture (# parcels/ acre)	Distance to nearest major highway (km)	Land type score
Willows-Beehive Bend	94.3	2.75	73.4	12.1	13
West Grimes	99.9	0.0	112	9.4	13
Arbuckle	93.4	0.73	90.8	0.7	15
Sycamore	89.8	0.0	235	14.9	11
Ryer Island*	NA	100	NA	7.0	NA
Bounde Creek	88.2	6.1	63	13.9	13
Lathrop	91.9	0.1	99	6.6	15
River Island	98	0.6	102	11.6	11
McDonald Island	73.5	1.7	147	11.5	10
Sutter Buttes	89.1	0.0	106.5	23.6	9
Malton-Black Butte	73.8	0.8	132.4	2.5	12
Robbins	100.0	0.0	88.9	22.8	11
Putah Sink	94.5	3.0	183.7	7.0	13
Conway Ranch	88.2	3.6	368.0	2.1	11
Dutch Slough	28.2	32.8	49.8	7.9	12
Vernalis	79.5	4.8	82.8	4.2	14
Wild Goose	98.2	0.0	278.9	25.8	9
French Camp	45.8	14.5	58.6	0.8	13
Suisun Bay*	NA	NA	NA	9.3	NA
Maine Prairie	66.2	0.0	196.3	17.5	10
Thornton & W.-Walnut Grove	96.8	0.0	426.7	3.5	11
Rio Vista	62.3	5.5	210.9	14.8	10
Todhunters Lake	78.6	9.3	179.5	0.9	12
Sutter City	81.6	0.2	68.6	28.0	11
Union Island	94.8	0.0	301.2	9.8	11
Lindsey Slough	56.3	0.0	299.3	22.8	7
Millar	89.0	8.2	117.1	12.3	11

*Table 10: Evaluation of surface land ownership. Red indicates areas of concern. *NA is used to indicate that parcel ownership information is not available, but thought to be 100% government owned (not ranked).*

Workstream 1 Conclusions

Based on the insights from the subsurface and surface technical assessments, we make the following conclusions and recommendations supported by the data in Table 11:

- While 27 fields were evaluated in this study, the 10 lowest ranking from a sub surface perspective also tend to have issues from a surface perspective (land ownership or potential significant community impact.
- 9 fields have a high subsurface rank, only 2 of which have potential significant community impact.
- We suggest the remaining 7 depleted gas fields be considered for futher study: Willows-Beehive, West Grimes, Arbuckle, Sycamore, Ryer Island, Bounde Creek, and River Island.

Field Name	Subsurface Rank	Land type score	Cal Enviroscreen %	Sites with high potential for health, environmental, and community impact
Willows-Beehive Bend	H	13	25.9	
West Grimes	H	13	64.8	
Arbuckle	H	15	64.8	
Sycamore	H	11	64.8	
Ryer Island*	H	NA	66.8	
Bounde Creek	H	13	25.9	
Lathrop	H	15	93.5	Flagged
River Island	H	11	63.7	
McDonald Island	H	10	93.5	Flagged
Sutter Buttes	M	9	37.6	
Malton-Black Butte	M	12	41.6	
Robbins	M	11	61.6	
Putah Sink	M	13	24.5	
Conway Ranch	M	11	54.9	
Dutch Slough	M	12	47.2	
Vernalis	M	14	54.8	
Wild Goose	M	9	61.9	Flagged
French Camp	L	13	99.2	Flagged
Suisun Bay*	L	NA	66.8	
Maine Prairie	L	10	54.7	Flagged
Thornton & W.-Walnut Grove	L	11	63.7	
Rio Vista	L	10	57.1	
Todhunters Lake	L	12	35.4	
Sutter City	L	11	37.6	
Union Island	L	11	93.5	Flagged
Lindsey Slough	L	7	77.8	
Millar	L	11	54.7	Flagged

Table 11: Summary of subsurface and surface finding . Red indicates areas of concern.

For future site characterization/next steps, we suggest applying Stage 3 criteria [3] to these 7 depleted fields. Stage 3 involves assessing the criteria shown in Table 12, as well as revisiting any criteria in Stage 1 or 2 for which there was not enough information to assess. Each of the criterion in Table 12 has an associated narrative which outlines the issues that should be considered during site characterization.

Category	Criteria	Narrative
Capacity and Injection Optimization	Number of Injection Wells Needed	The cost of the project increases with the number of wells that are needed for injection. However, there is an upper limit to how much can be injected into a single well. Frictional losses can be significant when injecting large volumes. There would be project risk if the project were to lose a well, injecting a large volume of CO_2, which could delay the project. All these factors should be evaluated when considering the number of injection wells.
	Vertical Heterogeneity	Vertical heterogeneity can increase the storage utilization of the reservoir.
	Horizontal Heterogeneity	Horizontal stratigraphic heterogeneities would guide the flow in a non-uniform areal distribution.
Retention and Geomechanical Risk Minimization	Top Seal Continuity	The top seal needs to be continuous over the spatial extent of the plume to minimize the chance of migration to shallower intervals or to the Earth surface.
	State of Stress in Top Seal	A clay-rich ductile formation is highly preferred. Low-stress anisotropy reduces the tendency for faulting and increases the hydraulic fracturing pressure.
	Quality of Bottom Seal	A bottom seal with permeability lower than 100nD is preferred. This will diminish the potential fluid migration pathway to the basement.
	Quality of Existing/Abandoned wells	The wells in the vicinity of the CO_2 storage site should have passed mechanical integrity tests, have wellbore and cement evaluation logs indicating no leakage pathways through the wells, or received approval from the regulatory bodies for an alternative demonstration that the well(s) will not be a potential CO_2 leakage pathway.
	Top Seal Capillary Entry Pressure	The top seal capillary entry pressure should be great enough to prevent CO_2 migration through that top seal. Account should be taken of the potential for non-0° CO_2 -brine contact angles with adjustments made to the minimum acceptable mercury injection capillary pressure as needed.
	CO_2 Secondary Trapping Mechanisms	Solubility, residual, and mineral trapping can make the CO_2 immobile and increases storage security. Each trapping mechanism takes progressively longer to occur and the amount of CO_2 trapped should be analyzed by numerical simulation.
	Pressure Buildup	Pressure change cannot exceed the hydraulic fracture pressure of the reservoir or the top seal nor increase the buoyancy pressure, so it exceeds the capillary entry pressure of the top seal.
	In Situ Pressure (confined reservoirs)	Strongly pressure depleted reservoirs may negatively impact a wide array of chemical and geomechanical processes relevant to both storage optimization and retention risk.
	Age of Fault Displacement	Determination of the age of the most recent fault displacement can show whether a fault is potentially active.
	Potentially Active Small-Scale Faults	If high-resolution geophysical data reveal the presence of potentially active faults, pressure changes should not exceed that which would be expected to induce slip on those faults.

Table 12: Stage 3 site characterization criteria. Source: Callas et. al. (2022, in review) [3].

Workstream 2: Evaluation of business and regulatory framework for H2 generation with CCS in California

Agreed Scope of Work:

- Detailed analysis of the hydrogen mobility markets across California with special attention paid to the certainty of growth curves for site selection.
- Assessment of the optimum capacity for a refueling station, and therefore the required hydrogen production volume, for this project.
- Evaluation of CCS regulatory issues in California (primacy, pore-space ownership, permitting process, etc.) and recommendations for navigating.
- Assessment of the risks affecting private sector investment decisions in CCS in California, including the risks associated with managing long-term liability of sequestered CO_2.

Hydrogen Mobility Market Analysis

To assess California's market potential for hydrogen in the transportation sector, we examined zero-emission vehicle (ZEV) growth projections for the state developed by the California Air Resources Board (CARB). CARB's Emission Factor, or EMFAC, database [22] contains both current and projected vehicle population by vehicle category (light, mid, and heavy-duty cars, trucks, buses etc.) and fuel/motor type (gasoline, natural gas, diesel, electricity, etc.) out until 2050. The EMFAC database contains "business as usual" (BAU) growth projections of zero-emission vehicles and does not distinguish between battery electric vehicles (BEVs) or fuel cell electric vehicles (FCEVs). By "business as usual" we mean expected growth in ZEVs based on current policy and regulation in place to spur ZEV adoption (i.e. ZEV adoption schedules). ZEV adoption schedules are in effect for mid and heavy-duty buses and trucks (Advanced Clean Truck and Innovative Clean Transit Rules) and are accounted for in the EMFAC database. While Governor Newsom has announced a goal to reach 100% ZEV sales in California by 2035 (EO N-79-20), CARB has yet to put forth a ZEV adoption schedule for passenger vehicles and so it is not taken into consideration in EMFAC. Instead of using EMFAC data exclusively for passenger ZEV growth projections, we also look to CARB's Mobile Source Strategy (MSS) which does consider N-79-20 and does split ZEVs into BEVs or FCEVs.

In addition to yearly vehicle population, EMFAC also provides annual estimates of fuel consumption by vehicle type. This data is used to assess the equivalent hydrogen demanded when these vehicles are to be converted to FCEVs.

We focus our results on Sacramento and the Bay Area as these are the regions we selected for further study for a new-build SMR with CCS facility. Conveniently, EMFAC data can be analyzed by region. For the MSS, we only have state-level data and so we multiply the total FCEV projections from the MSS by the fraction of vehicles on the road in California that drive in Sacramento and the Bay Area.

FCEV Projection Methodology and Results

EMFAC contains ZEV growth projections and does not distinguish between FCEV and BEVs. We were tasked with determining a plausible fraction of future ZEVs that will be fuel cell electric. For this analysis, we split the Bay Area and Sacramento vehicles into 3 vehicle categories based largely on vehicle size and expected FCEV market share, and developed low, mid[1], and high FCEV growth projections out until 2045 for these vehicle categories.

The first vehicle category includes all passenger vehicles (<8,500 lbs). It is generally agreed today that in the passenger vehicle space, BEVs will hold market share over FCEVs as BEVs are more mature and require less infrastructure. To reflect this, we assume in a lower FCEV penetration case that only 5% of passenger ZEVs each year (from EMFAC) will be FCEV and the remaining will be BEV. The high FCEV penetration case will draw FCEV population numbers directly from the MSS (Figure 6). This FCEV population number must only be multiplied by the fraction of vehicles in California driving in the Bay Area and Sacramento.

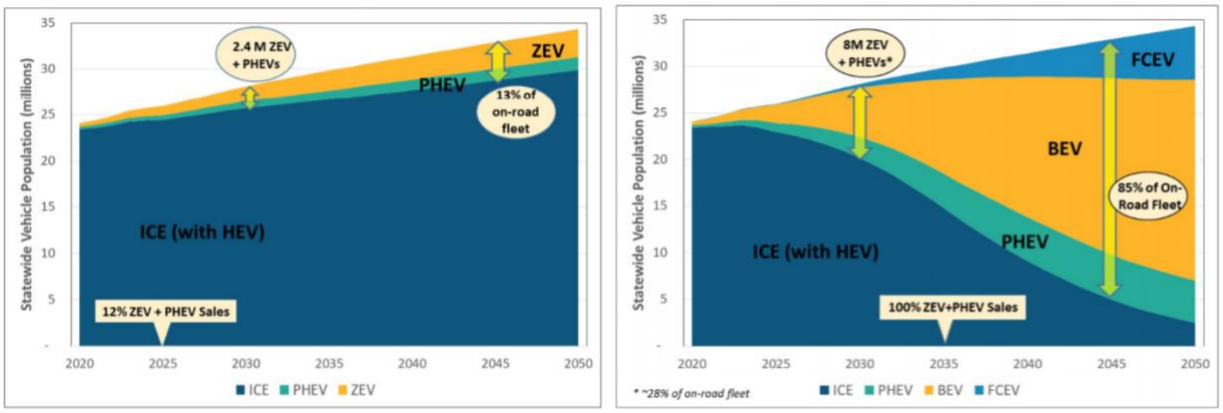

Figure 6: CARB BAU (left) and Mobile Source Strategy (right) for vehicle type population projections in California [23] [1].

The second vehicle category includes both mid-duty and light heavy-duty vehicles (between 8,500 lbs and 26,000 lbs) as well as school and transit buses. While BEVs are still expected to be more prevalent than FCEVs into the future for these vehicle categories, there is more uncertainty. Bus, van, and small truck operators will likely choose a ZEV type based on cost, infrastructure availability, route length, and business model fit. For these vehicle types, we assume a low-end FCEV growth would be 5% of ZEVs each year from EMFAC, and a high-end FCEV penetration would be 50% of ZEVs from EMFAC. The methodology can be better visualized in Figure 7.

[1] Mid-case projections are an average of the low and high projection scenarios

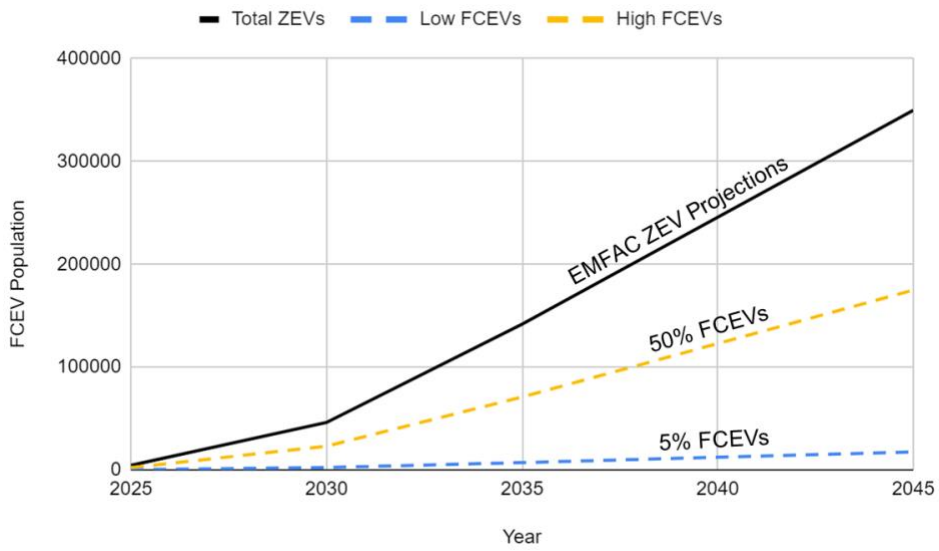

Figure 7: Mid-duty vehicle (MDV) FCEV growth projection methodology.

The third vehicle category includes all other heavy heavy-duty vehicles (>26,000 lbs). Tractor trailers travelling long-distances and for much of the day are most numerous in this category. For this vehicle category, the market is expected to be dominated by fuel cell ZEVs as they have shorter refill times, longer ranges, and a higher on-board energy storage density in comparison to BEVs. For the heavy heavy-duty vehicles, we assume a low-end FCEV growth of 20% of ZEVs each year from EMFAC, and a high-end FCEV penetration of 90% of ZEVs from EMFAC. This projection methodology is the same as visualized in Figure 2 but for heavy heavy-duty vehicles and this different FCEV penetration percentages.

Summing results from each of these three vehicle categories, we generated Figure 3. As is shown, in the high FCEV adoption case, the Bay Area and Sacramento reach over 1.5 million FCEVs by 2045. In the low adoption case however, we could see on the order of 100,000 FCEVs on the road by 2045. Somewhere between these two estimates is the most likely outcome.

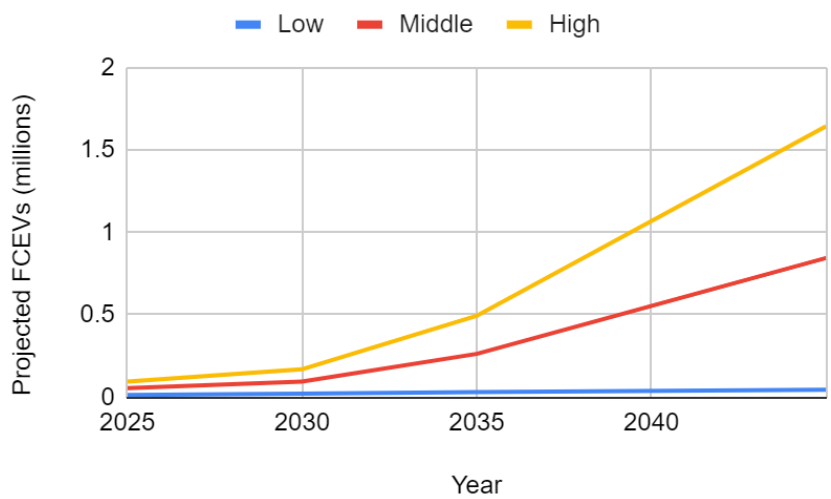

Figure 8: FCEV population projections.

Hydrogen Demand Projection Methodology and Results

After assessing FCEV growth in the Bay Area and Sacramento, we then developed a methodology for estimating hydrogen demand to fuel FCEVs into the future. This ties to the Workstream 2 assessment of optimal SMR-CCS capacity to build-out to minimize hydrogen fuel costs.

To convert FCEV population into FCEV hydrogen demand, we use Eq. 1:

$$(H_2\ per\ FCEV\ per\ year)_i = \frac{HV_P}{HV_{H2} * FER_i} * (2020\ Fuel\ per\ ICEV\ per\ year)_i \qquad \text{(Eq.1)}$$

where:

- i = vehicle category (passenger, mid-duty, light heavy-duty, heavy heavy-duty, buses)
- $2020\ Fuel\ per\ FCEV\ per\ year$: petroleum requirement for an internal combustion engine vehicle (ICEV) on the road in 2020 (kg). These values are derived from the EMFAC database [2] for each vehicle category analyzed.
- HV_P: petroleum heating value (MJ/kg). Equal to 120 MJ/kg H_2
- HV_{H2}: heating value of hydrogen (MJ/kg). Equal to about 42 MJ/kg diesel or gasoline.
- FER: fuel economy ratio (MJ petroleum needed / MJ H_2 needed). Values shown in Table 1.
- $H_2\ per\ FCEV\ per\ year$: hydrogen requirement for each FCEV on the road for one year (kg)

By using Eq. 1, we are assuming:

- An average value petroleum/H_2 consumption per year for each vehicle category

- Vehicles will drive about the same amount in 2020 as they do each year into the future
- FCEV vehicles see minimal efficiency gains into the future

Table 13 shows the values we use for FER for the different vehicle categories. These values are derived from a paper written by Argonne National Laboratory [24]. FER is typically lower for vehicles that drive on highways in a constant state of motion, and higher for vehicles driving in the city with consistent stopping and starting. This is because ICEVs are much more efficient in a constant state of motion.

Vehicle Category	Fuel Economy Ratio
LDVs (< 8,500 lbs)	2
MDVs (> 8,500 lbs and < 14,000 lbs)	1.8
LHDVs (> 14,000 lbs and < 26,000 lbs)	2
Buses (all weights)	2
HHDVs (> 26,000 lbs)	1.65

Table 13: FER by vehicle category.

Multiply H_2 per FCEV per year by FCEV vehicle population projections for each vehicle category and then summing vehicle category results (Eq. 2), we generate hydrogen demand projections for FCEVs in the Bay Area and Sacramento (Figure 9).

$$(H_2\ Demand)_t = \sum_i (Population)_{t,i} * (H_2\ per\ FCEV\ per\ year)_i$$

With:

- t = future year
- $Population_{t,i}$ = FCEV Population in category i at year t

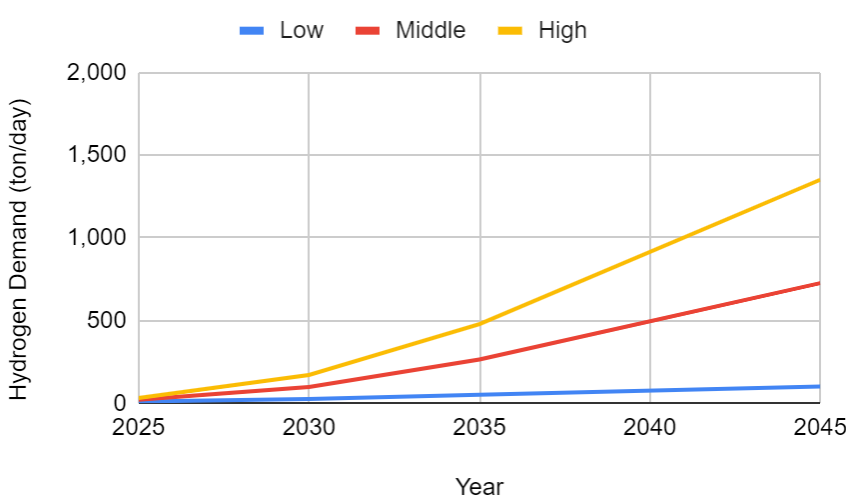

Figure 9: H_2 demand projections for the Bay Area and Sacramento transportation sector.

As is shown in Figure 9, hydrogen demand for FCEVs in the Bay Area and Sacramento could reach as high as 500 metric ton/day by 2035 with further infrastructure development and policy support or could be as low as 50 metric ton/day in 2035 in a BAU scenario. It is most likely that the true hydrogen demand for the transportation sector in the Bay Area and Sacramento will fall somewhere between the high and low demand scenarios shown in Figure 4.

Refueling Station Buildout Analysis

In 2020, California reached 44 total hydrogen refueling stations with a total dispensing capacity of 14.3 metric ton/day. In the San Francisco Bay Area and Sacramento specifically, there were 18 hydrogen stations online in 2020. These stations have a total dispensing capacity of 6.7 metric ton/day, or on average about 370 kg/day for each station. By 2026, it is estimated that around 176 hydrogen refueling stations come online in California with a total of about 170 metric ton/day capacity. At least 30 metric ton/day capacity is expected to be built out in the Bay Area and Sacramento by this time. [25]

Shown in Figure 10, the majority of refueling stations in the Bay Area and Sacramento today are in densely populated areas. Into the future, further refueling station infrastructure could be placed along major highways routes such as I-5 and I-80 that can support both heavy-duty tractor trailers and passenger FCEVS.

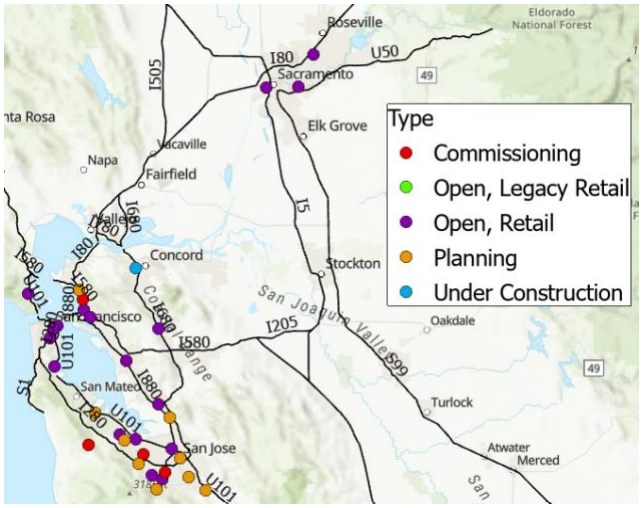

Figure 10: 2021 Hydrogen refueling station landscape in the Bay Area and Sacramento [3].

Given the uncertainty surrounding the hydrogen mobility market in California into the future, we assess how many refueling stations an SMR-CCS facility would be able to support based on facility size and average refueling station capacity (Table 14). We chose SMR-CCS facility sizes that reflected 2035 hydrogen demand estimates from Figure 9 (50, 250, and 500 metric ton/day) and average refueling station capacities that are most likely (500 to 1500 kg/day) given current refueling station capacities and future station capacity projections detailed above [25].

SMR-CCS Facility Size (metric ton/day)	Average Refueling Station Capacity (kg/day)				
	500	**750**	**1000**	**1250**	**1500**
50	100	67	50	40	34
250	500	334	250	200	167
500	1000	667	500	400	334

Table 14: Possible number of hydrogen refueling stations supported by an SMR-CCS Facility.

CCS Regulatory Landscape in California

Note: Much of the insight provided in this section was extracted from the following report: Energy Futures Initiative and Stanford University. "An Action Plan for Carbon Capture and Storage in California: Opportunities, Challenges, and Solutions (2020) [26].

Over the last decade, California has enacted a number of policies that could pave the way for CCS to contribute to meeting the state's ambitious climate targets. However, even with these policy drivers, a number of factors have made it difficult for new CCS projects to move forward, and there are currently no operational large-scale CCS projects in California. While incentives (45Q and LCFS) help to make the case for investment more attractive, other issues, including a complex and untested regulatory environment (including permitting process), lack of clarity on pore space ownership, and primacy issues have resulted in hesitation from project investors.

Incentives (45Q and LCFS)

Current financial incentives for CCS in California include the federal Section 45Q tax credit and California's Low Carbon Fuel Standard. The federal 45Q tax credit is linked to the installation and use of carbon capture equipment that directly removes CO_2 from the atmosphere. The current values of the credit are $50/metric ton CO_2 for geologic storage and $35/metric ton CO_2 for EOR or if used for products. Facilities must begin construction by January 1, 2026. Minimum emission size constraints and a 12 year timeframe for which to benefit for the credit also limit potential impact.

The LCFS establishes a credit trading system designed to reduce the carbon intensity (CI) of transportation fuels. As of May 2022, LCFS credits were trading for around $130 per metric ton$CO_2$e, although they have traded for over $200 per metric ton CO_2e in the past year. Blue hydrogen would be eligible for the LCFS credit if it is used in the fuel transportation market in California.

Permitting Issues

All infrastructure projects in California must meet permitting requirements at the local, regional, state, and federal levels, including environmental requirements with the goal of protecting public health, land, water, and air resources. The regulatory permits and processes required for a simple and geographically contained CCS project (e.g. one with co-located capture and storage) are shown in Figure 11.

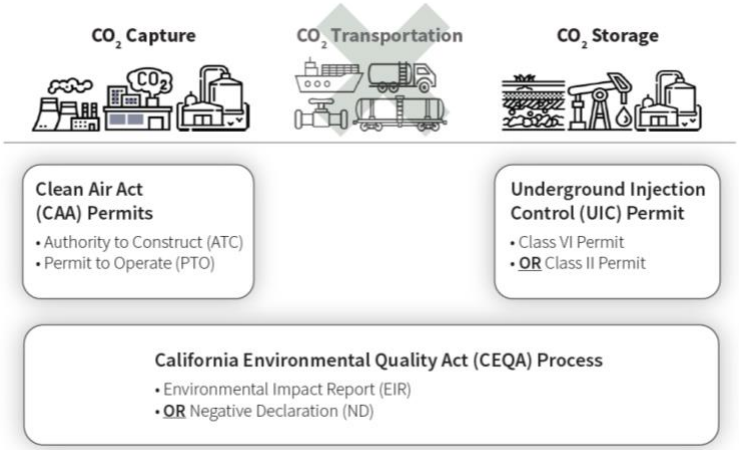

Figure 11: Key permitting processes required for all CCS projects in California. Source: Energy Futures Initiative and Stanford University, 2020 [26].

In addition, projects seeking to receive LCFS credits (described above) must also complete the Permanence Certification process, which includes requirements to ensure that injected CO_2 will remain underground for 100+ years after injection.

A comprehensive evaluation of all the potential permits that a CCS project might need to acquire was recently published by LLNL in a report entitled "Permitting Carbon Capture and Storage Projects in California". The key findings from this report are listed here [27]:

- California has a robust and extensive array of regulations and institutions that are collectively sufficient to protect public health, safety, and the environment while CCS is being deployed.
- Permitting a sufficient number of sound CCS projects to achieve California's climate goals is unlikely due to scattered and/or poorly defined agency jurisdiction boundaries and responsibilities, inefficient and/or time-consuming processes, and inadequate staff resources.
- Environmental review, primarily under the California Environmental Quality Act and related litigation but also under the National Environmental Policy Act, will be a key determinant of project authorization timelines, which will likely span multiple years.
- The authorization process can be made more efficient while retaining its integrity and credibility with relatively few and straightforward operational and organizational fixes, and without major reforms.
- A small number of technical regulatory and statutory fixes would enable deployment of CCS technologies at the scale needed in the longer term.
- Project developers should anticipate and be equipped to handle a complex and technically involved authorization process.

Pore Space Ownership

California has not clarified pore space ownership in law. Pore space refers to the fraction of rock volume not occupied by solid matter, which could be used for storing CO_2. CARB's CCS

Protocol requires that a project operator must show proof of exclusive right to use the pore space in the storage zone in order to obtain LCFS credits.

In California, there is uncertainty about who owns underground pore space rights. California state agencies will need to provide additional regulatory guidance to clarify legal requirements and reduce costs and complexity of pore space ownership. SB 1101 (Caballero) was drafted to address the pore space issue, and is currently making its way through various senate committees.

Primacy

The EPA UIC regulations for Class VI wells have a default of 50 years of Post-Injection Site Care (PISC) responsibility after CO_2 injection wells have been capped. States that have primacy for Class VI wells can implement shorter PISC timeframes if they can demonstrate that a shorter timeframe will not threaten the safety of underground sources of drinking water [2].

California does not have primacy for Class VI wells. The first few Class VI well took upwards of 5 years to obtain EPA approval. In the only two states that have obtained primacy from the EPA, North Dakota and Wyoming, Class VI primacy offers regulatory certainty to developers of CCS.

CCS Investment Risks

Note: Much of the insight provided in this section was extracted from the following report: Energy Futures Initiative and Stanford University. "An Action Plan for Carbon Capture and Storage in California: Opportunities, Challenges, and Solutions (2020) [26].

There are a number of revenue and cost challenges for CCS projects that have a material effect on CCS economic attractiveness.

Revenue Challenge: LCFS Credit Market Uncertainty and Policy Risk

The LCFS is the single largest financial incentive for eligible CCS projects in California. The volatility of LCFS credit market, its vulnerability to policy changes, and the allocation of a percentage of credits away from the project operators and into a Buffer Account may limit the attractiveness of the LCFS as an incentive for new investments in CCS. Also, over time, as the state decarbonizes, there may be fewer credits to trade, diminishing the value of the LCFS [2].

Revenue Challenge: Limitations of the Federal 45Q Tax Credit Design

Although the 45Q credit is a valuable incentive for CCS project development, some aspects of its design limit its effectiveness. The January 2026 deadline for project commencement is challenging, especially given the current economic downturn caused by COVID-19.

The 45Q tax credit may not cover the full costs of CCS projects alone, but it is a significant source of revenues and can be a foundational component of covering a project's costs. The duration of 45Q benefits (12 years) is much shorter than the lifespan of a typical capture facility (typically 20 or more years).

Cost Challenge: Financial Responsibility Associated with UIC Class VI Wells

Under EPA's federal UIC VI well permit, a trust fund is established by a project developer to cover the costs of: corrective action, emergency and remedial response, injection well plugging, PISC, and site closure. An illustrative example is the FutureGen project in Illinois that was a Class VI demonstration project that established an approximately $52 million trust fund for injecting 1.1 $MtCO_2$ annually. This project-specific, upfront cost burden has a non-trivial effect on overall project returns. Using FutureGen as a baseline, a proportioned trust fund established for an ethanol plant would reduce IRR by 10% (e.g. if IRR was 20%, it would become ~18%). While coverage is clearly important, a more efficient approach may be to pool funding into a central storage facility that serves multiple capture facilities [2].

Workstream 2 Conclusions

Based on our analyses of hydrogen mobility markets in Northern California in conjunction with an evaluation of CCS regulatory and business issues, we find the following:

- Future hydrogen demand for mobility in Northern California is uncertain. In a mid-case scenario, about 250 metric ton/day of hydrogen demand would be expected by 2035. This is a typical size of an SMR that would be able to support between 167 and 500 refueling stations depending on refueling station capacities.
- A number of regulatory issues are hindering CCS development in California, including pore space ownership, permitting, primacy. Future legislation addressing these issues will be critical to success of CCS in California.
- Commercial risks include the uncertainty of federal and state policy incentives (e.g. 45Q and LCFS) and securing capital investment for high risk projects with multiple stakeholders and uncertain regulatory climate.

Workstream 3: Technoeconomics of H_2 generation with CCS in California

Agreed Scope of Work

- Economic assessment of cutting-edge hydrogen SMR plants at a variety of scales in Northern California.
- Assessment of CO_2 capture costs associated with new build SMR.
- Technoeconomic assessment of CCS of CO_2 from hydrogen generation.
- Comparative assessment of the technoeconomics of alternate hydrogen generation pathways (e.g., green hydrogen from electrolysis, biomass, renewable natural gas, etc).

In this workstream we discuss our SMR-CCS techno-economic modeling framework, the data used, and results of the techno-economic assessment given different policy, facility sizes, and hydrogen demand scenarios.

The model

We use a detailed financial model to calculate the levelized cost of hydrogen (LCOH). This financial model creates an income statement for a suitably parameterized blue hydrogen facility, followed by a cash flow statement. The cash flows are then used to calculate the net present values (NPV) for the equity and debt investors. The model allows for the demand for hydrogen from the facility to be different from the generation capacity. It also assumes that demand for hydrogen scales linearly to projected demand in 2035.

By design, recall that the NPV for the debt investor is zero; whereas the LCOH is calculated as the per unit revenue at which the NPV for the equity investor is zero. That is, at per unit revenue equal to LCOH, the NPVs for both investors are zero, i.e., all investors not only recover their invested capital but also make returns that meet their expectations. Thus, LCOH is the minimum per unit revenue where all investors would decide to invest.
The model accounts for all costs associated with blue hydrogen production. This includes capital expenditure (CAPEX) and operating expenditure (OPEX) for steam methane reforming (SMR), and carbon dioxide (CO2) capture. OPEX includes fuel (natural gas as well as electricity) variable costs, non-energy fixed costs, as well as storage and transport variable costs. Thus, as defined, LCOH is also equal to the average (appropriately discounted) cost of blue hydrogen production over the lifetime of the facility.

In our model, debt is amortized equally over the debt tenor, which is typically set mutually between the debt investors and the facility. The interest payments in any particular year are calculated on remaining principal at the end of the previous year. Thus, the payments to the debt investors equal the sum of amortized principal and interest. We assume that all remaining cash flows are used to pay dividends to equity investors over the lifetime of the project. Finally, we model depreciation using a double declining balance method [28].

The model allows for calculation of LCOH without any subsidies. We denote this as *unsubsidized* LCOH. The model also allows for incorporation of various existing and proposed policies to calculate LCOH in presence of subsidies; we denote this as *subsidized* LCOH. The existing policies include the federal tax credit for carbon sequestration, also known as 45Q, as well as the California Low Carbon Fuel Standard (LCFS) revenue credit. Note that the former (i.e., 45Q) is a tax credit: it reduces the tax liability of the facility or its investors, and we assume that the investors can avail of this credit. On the other hand, the latter (i.e., LCFS) is a revenue credit: it increases the taxable revenue of the facility.
Based on President Biden's Build Back Better plan, we also model the production tax credit (PTC) as well as the investment tax credit (ITC). Both work in a way like 45Q. Our model allows for each of the existing and proposed subsidies to be applied independently of each other. This enables testing the impact of the policies on LCOH, individually as well as in combination. In this context, given that the tax credit policies are mutually exclusive, the only possible combinations are subsidy pairs where one constituent is always LCFS whereas the other constituent is one of the tax credit policies.

Data

Our baseline model assumes a new build SMR-CCS hydrogen production facility sized at 250 metric ton/day. This facility size was chosen based on the mid-case hydrogen demand forecasts developed as part of the pre-project scoping analysis (Figure 12).

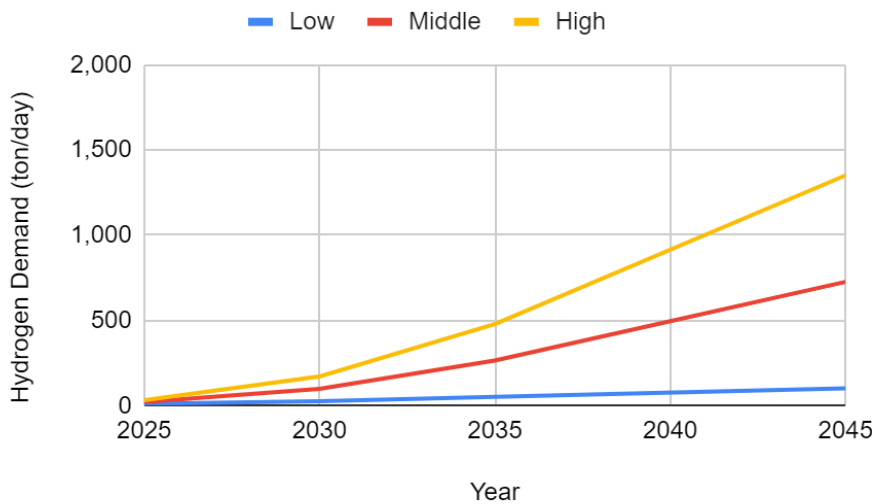

Figure 12: Bay Area and Sacramento hydrogen demand forecast for the transportation sector.

The facility will use an MEA flue gas capture system to achieve 90% capture of all CO_2 from the facility. It will be constructed over a 3-year period from 2023 to 2025, will begin operations in 2026, and will operate for a total of 25 years [28] .
To calculate levelized hydrogen revenue from LCFS credits, the following equation is used:

$$LCFS\ Revenue\ \left(\frac{\$}{kg\ H_2}\right) = \frac{(CI_{BL} - CI_{H2})}{1*10^6} * LHV_{H2} * EER * LCFS\ Credit\ Value \qquad \text{(Eq.1)}$$

Where:

- CI_{BL} = carbon intensity of baseline fossil fuel (g CO_{2e} / MJ)
- CI_{H2} = carbon intensity of produced hydrogen (g CO_{2e} / MJ)
- LHV_{H2} = lower heating value of hydrogen (MJ/kg)
- EER = energy economy ratio (MJ / MJ)

All input parameter values used for the technoeconomic model are found in Table 15.

Input Categories	Input Parameters	Values	Units	Source
Capital	Baseline H_2 production capacity	250	metric ton/day	Assumption (see Figure 1)
	Baseline SMR capital cost	164	$ in millions	NREL 2018 [29]
	Baseline CO_2 capture capital cost	194	$ in millions	Shell, NPC 2019 [30]
Operations	SMR fixed O&M cost	3	% CAPEX/year	Shell, NPC 2019 [30]
	CO_2 capture fixed O&M cost	15	% CAPEX/year	Shell
	Baseline natural gas price	6.5	$/MMBTU	PG&E [31]
	Electricity rate	0.104	$/kWh	PG&E [32]
	SMR electricity input	0.6	kWh/kg H_2	NREL 2018 [29]
	SMR natural gas input	3.3	kg / kg H_2	NREL 2018 [29]
	CO_2 capture electricity input	0.13	kWh/kg CO_2	Shell, NPC 2019 [30]
	CO_2 capture natural gas input	0.04	kg / kg CO_2	IEA 2017 [33]
Financials	Project economic life	25	Years	Shell
	Project construction period	3	Years	Shell
	Inflation rate	2.5	%	Assumption
	Weighted average cost of capital (WACC)	6.54	%	NETL 2019 [28]
	Equity rate	10	%	
	Debt rate	5	%	
	Debt duration	15	Years	
	Leverage	55	%	
	Tax rate	26	%	
	Depreciation rate	150	% (declining balance)	
Incentives	45Q tax credit	50	$/ metic ton CO_2 captured	CRS 2021 [34]
	LCFS Credit Value	50	$/ metric ton CO_2e avoided	Assumption [35]
	Energy Economy Ratio	2	MJ gas / MJ H_2	CARB 2018, 2020 [35], [36]
	Baseline Carbon Intensity (CI) Score	100.8	g CO_2e / MJ	
	SMR CI Score	62	g CO_2e / MJ	
	SMR-CCS CI Score	22	g CO_2e / MJ	

Table 15: Key input parameters to technoeconomic model.

Unsubsidized levelized cost

Our model finds the unsubsidized LCOH for blue hydrogen to be $3.59/kg. This is much higher than the global range of $1.2-$2.1/kg, as predicted by the IEA.[2] We believe that it may be due to two factors: first, the natural gas prices in California are higher than (the US) average prices; second, we assume that the plant output scales linearly with capacity in ten years, in line with how market demand would scale. The sensitivity to the latter is significant – the LCOH comes down to $2.88/kg (i.e., by 20%) if we assume that the demand is equal to capacity from the beginning. In fact, as we see later, if demand equals capacity from the beginning, the fully subsidized LCOH for blue hydrogen is close to $1, the LCOH for grey hydrogen.

[2] See Global average levelised cost of hydrogen production by energy source and technology, 2019 and 2050 – Charts – Data & Statistics - IEA

Levelized cost under current policies

We calculate subsidized LCOH for blue hydrogen under three scenarios, as shown in Table 16. First, in presence of just 45Q; second, in presence of just LCFS; and third, when both 45Q and LCFS are present. We find these numbers to be $3.12/kg, $2.25/kg, and $1.79/kg. That is, the reductions in LCOH in these three cases are 13%, 37%, and 50%.

The implications of these results are as follows. First, 45Q by itself does not provide significant reductions (i.e., about 1/8th) in LCOH, and 45Q by itself is unlikely to be key in making blue hydrogen cost-effective. Second, LCFS by itself provides significant reductions (i.e., more than 1/3rd) in LCOH, and LCFS by itself is likely to be key in making blue hydrogen cost-effective. Third, a combination of both is better than simply having one policy and brings the subsidized LCOH to half of the unsubsidized one.

Subsidy	LCOH ($/kg)	%-reduction
No subsidy	$3.59	
45Q only	$3.12	13%
LCFS only	$2.25	37%
45Q and LCFS	$1.79	50%

Table 16: Current policy impact on LCOH.

Sensitivity analysis on levelized cost

We also performed sensitivity analysis on some key parameters, starting from the fully subsidized case, i.e., with both 45Q and LCFS present. These sensitivities are on natural gas prices and demand realizations. The former is calculated using natural gas prices of $10/MMBtu and $15/MMBtu (i.e., both downsides), whereas the latter is calculated using the low and high demand projections of 50 metric ton/day and 500 metric ton/day (i.e., one downside and one upside). For demand, we also use a case where the demand is equal to the capacity from the beginning (i.e., an upside).

Sensitivity	Fully subsidized LCOH ($/kg)	%-change
None	$1.79	
Natural gas price $10/MMBtu	$2.64	+47%
Natural gas price $15/MMBtu	$3.85	+115%
2035 demand 50 metric ton/day (linear increase)	$6.31	+252%
2035 demand 500 metric ton/day (linear increase)	$1.36	-24%
2035 demand 250 metric ton/day (step increase)[3]	$1.10	-38%

Table 17: Sensitivity analysis on fully subsidized LCOH.

Table 17 contains the LCOH values given the stated sensitivities. For natural gas prices of $10/MMBtu and $15/MMBtu, we get subsidized LCOH as $2.64/kg and $3.85/kg, respectively, i.e., increases of 47% and 115%, respectively, from the baseline of $1.79/kg.

[3] LCOH results in this case are comparable to those generated in the pre-scoping phase of the project for the Bay Area and Sacramento Valley. The change from $1.26/kg in the pre-scoping phase to $1.10/kg in the final version of the model can be attributed to the development of a project financing component of the model

For demands of 50 metric ton/day and 500 metric ton/day in 2035 (with linear scaling[4]), we get subsidized LCOH as $6.31/kg and $1.36/kg, respectively, i.e., an increase of 252% and a decrease of 24%, respectively. Furthermore, in the case where demand scales to capacity (of 250 metric ton/day) from the beginning, we get subsidized LCOH as $1.10, i.e., a decrease of 38%. Figure 13 contains an illustration of how facility output scales under different demand scenarios on a fully subsidized basis.

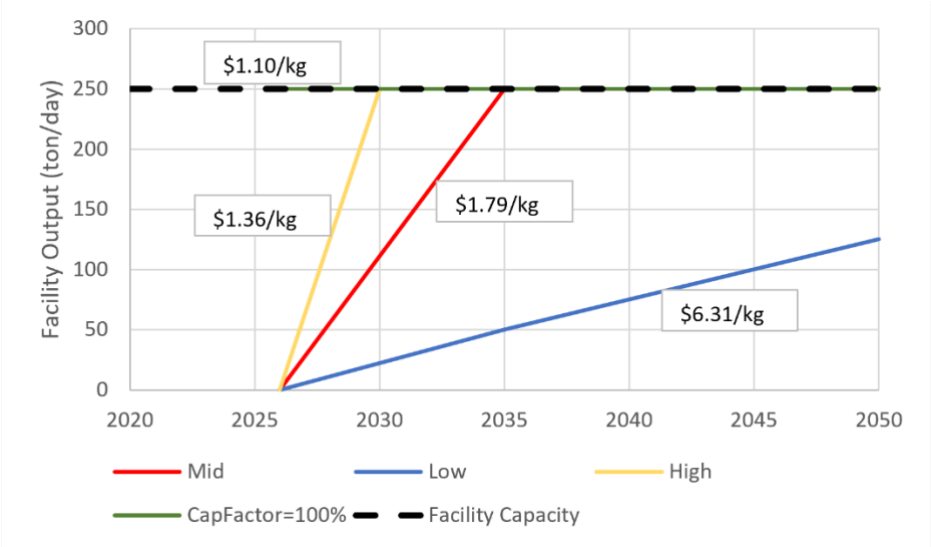

Figure 13: Impact of changing demand on fully subsidized LCOH.

The implications of these results are as follows:

- The subsidized LCOH is quite sensitive to natural gas prices. This risk is real given that long-term contracts for natural gas are hard to find and that natural gas is likely to become more expensive as California moves away from natural gas.[5]
- The subsidized LCOH is very sensitive to the low demand case. However, this is not a likely scenario given California's climate ambitions, in particular the 2045 net-zero target, and the crucial role of clean hydrogen in decarbonizing many sectors.[6]
- The subsidized LCOH is not that sensitive to the high demand case, showing that overbuilding a plant is riskier than underbuilding it. This suggests that one option could be to build the plant in stages, as more clarity emerges on realized demand.
- In the best case – when demand scales to capacity right away – the subsidized LCOH is very close to $1/kg, in which case blue hydrogen is cost-competitive with grey hydrogen. This opens a significant market.

Figure 8 summarizes how LCOH is impacted by both facility size and hydrogen demand scenario (scenarios shown in Figure 6).

- Under the high hydrogen demand scenario, the LCOH of the SMR facility will be lowest no matter the facility size; furthermore, a 250 metric ton/day or 500 metric

[4] This means that demand scales to the maximum demand in 10-years, which means that for a demand of 500 metric ton/day, we get to the capacity of 250 metric ton/day before year 10.
[5] See New California rules move state away from natural gas in new buildings | Reuters
[6] See Net-Zero Emissions Bill Advances in the California State Senate | Environmental Defense Fund (edf.org)

ton/day facility will be lower cost than a 50 metric ton/day facility under the high hydrogen demand scenario. This is due to lower relative facility capital and O&M costs with scale.

- In the medium hydrogen demand scenario, a facility of 250 metric ton/day comes at a lower cost ($1.79/kg) in comparisons to a 50 metric ton/day ($2.13/kg) or 500 metric ton/day ($2.19/kg) facility. This is due to lower relative capital costs with scale, and lower costs associated with higher capacity factor facilities
- Under the low hydrogen demand scenario, the LCOH for the SMR facility would be largest no matter the facility size, and a smaller facility is cost optimal because it would operate at the highest average capacity factor for the life of the facility

Figure 13 shows that there is the least amount of investment risk for a smaller SMR-CCS facility in the Bay Area and Sacramento. However, building a smaller facility will be more costly if it turns out hydrogen demand rises similarly to the mid or high demand growth scenarios in Figure 14. Recent policy trends in California indicate that the business-as-usual ZEV growth projection (low growth scenario in Figure 12) is not a likely outcome, especially for passenger vehicles[7]. This would indicate that the mid or high hydrogen demand scenarios are more likely, although, it remains to be seen exactly how FCEVs evolve in a ZEV market primary dominated by BEVs at this time. As of now, the consensus opinion is that FCEVs will dominate in the long-haul trucking space. This provides some assurance that the actual hydrogen growth in the Bay Area and Sacramento will exceed the low growth scenario shown in Figure 12.

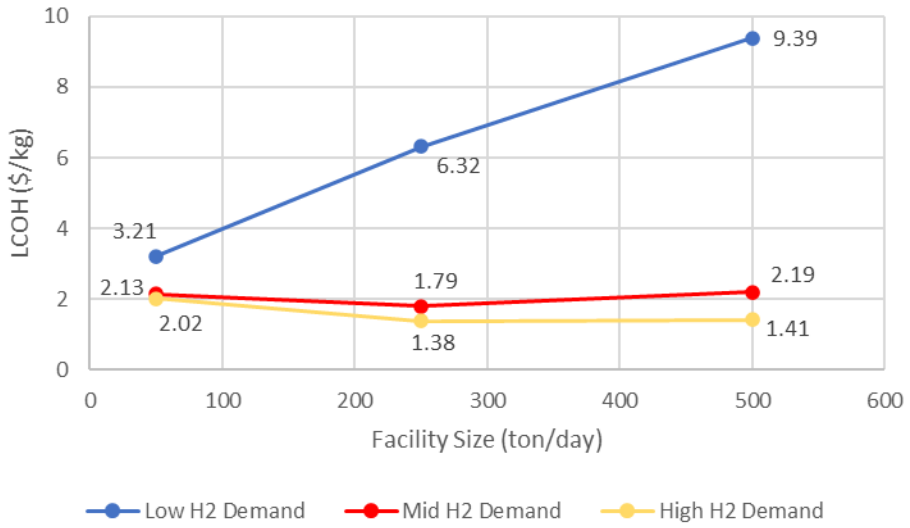

Figure 14: Impact of facility size and demand scenario on LCOH.

Finally, checking for the sensitivity to the size of the plant, in the case where demand is equal to capacity from the beginning, and in the presence of both 45Q and LCFS, we get the fully subsidized LCOH to be $3.20/kg and $0.86/kg, respectively, for capacities of 50 metric

[7] CARB has yet to set forth a regulation for passenger ZEV adoption rate schedules. Once this is passed, policy-based BAU scenarios will be more optimistic about ZEV growth

ton/day and 500 metric ton/day. Again, the sensitivity to low capacity is much higher (i.e., +251%) than the sensitivity to high capacity (i.e., -22%).

Impact of proposed policies on levelized cost

We now examine the impact of proposed policies under the Build Back Better plan. We assume that the blue hydrogen plant is availing the bonus rates by satisfying prevailing wage and apprenticeship requirements. This means an ITC of 30% and a PTC of $3/kg. Furthermore, we test the case when the carbon intensity of blue hydrogen in 3 kg CO_2/1 kg H_2, that allows for only 20% of the maximum PTC, i.e., an available PTC of $0.6/kg. Using these assumptions, we calculate the subsidized LCHO under the following three cases. First, ITC by itself; second, PTC by itself; third, PTC with LCFS. We find the subsidized LCOH to be $3.21/kg, $3.18/kg, and $1.85/kg, respectively. Recall that the subsidized LCOH for 45Q by itself and for the combination of 45Q and LCFS are $3.12/kg and $1.79/kg, respectively.

The implications of these results are as follows.

- First, ITC and PTC on their own provide a similar subsidy to 45Q. In fact, 45Q by itself provides better cost-effectiveness than either ITC (by approximately 3%) or PTC (by approximately 2%), where PTC is marginally better than ITC which fares worst.
- Second, when PTC is combined with LCFS, it is less cost-effective than the 45 Q and LCFS combination, by approximately 3%.

These results suggest that the Build Back Better plan, the way it stands today, doesn't help with making blue hydrogen cost competitive.

Levelized cost comparison

Very few studies have looked at the LCOH of clean hydrogen production pathways under California's current policy landscape. Bracci et al. 2022 [37] is an exception. In addition to SMR with CCS, it explores SMR with biogas blending and electrolysis hydrogen production (Figure 4). In each of the SMR pathways examined, it assumes a 250 metric ton/day facility operating at 100% capacity for the life of the facility. This is the comparable to our "CapFactor = 100%" scenario in Figure 13.

As shown in Figure 15, LCFS and 45Q incentives available in California lead to SMR with CCS costs that are cost competitive with grey hydrogen (SMR). In addition, under LCFS, dairy biogas has a negative carbon intensity when captured and utilized, which allows for significant cost savings when dairy biogas can be used in an SMR. The LCFS savings would be even more significant than shown in Figure 4 if the facility included both dairy biogas blending and CCS.

In comparison to SMR-CCS, the LCOH of hydrogen production through electrolysis using grid or renewables is higher (Figure 9). Even in the case where an electrolyzer can be directly connected to both a wind and solar farm to maximize utilization, the levelized cost of hydrogen is on the order of $3/kg with incentives, while SMR pathways are around $1/kg with incentives. This gap is likely to narrow, given DOE's Hydrogen Shot initiative to reduce the cost of electrolysis using renewables to $1/kg by 2030, via a combination of electrolyzer

advancements and continued reductions in renewable electricity costs. Despite this, near-term techno-economic models still point to SMR-CCS being the cheaper hydrogen generation pathway to kickstart a clean hydrogen economy in California.

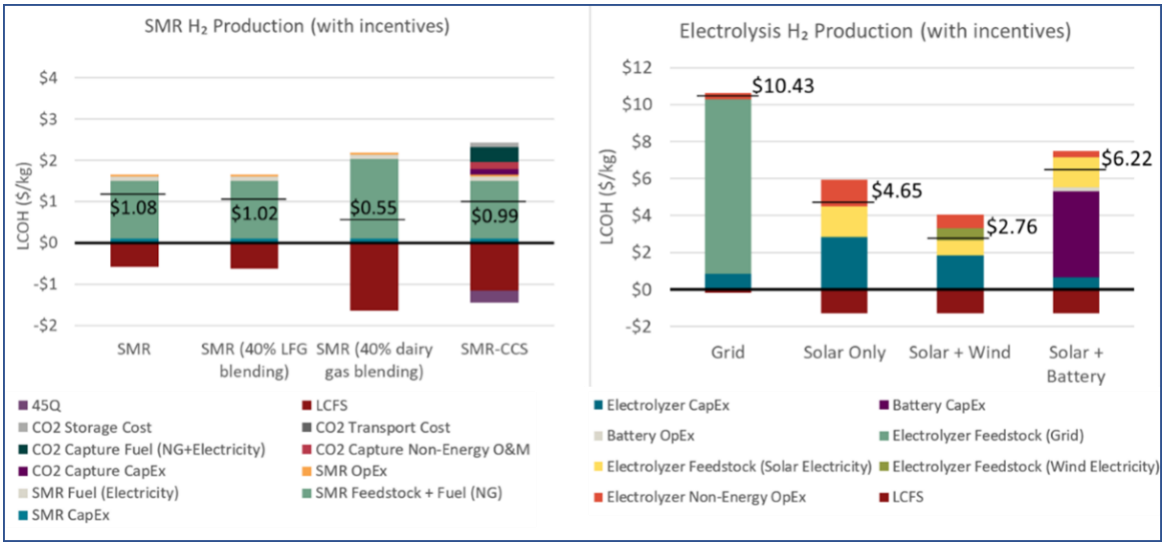

Figure 15: Levelized cost comparison of clean hydrogen production methods (includes California rates and subsidies): left SMR production and right electrolysis production. Both cases include incentives.

Due to data availability constraints, Bracci et al. (2022) did not explore LCOH for biomass and coal gasification with CCS or auto-thermal reforming (ATR) with CCS. Nevertheless, NETL has compared the levelized cost of these hydrogen production methods [38], albeit on a general location and unsubsidized basis. As is shown in Figure 16, NETL found SMR-CCS and ATR-CCS levelized costs to be very similar (~$1.60/kg). The primary difference of ATR to SMR is that ATR requires an air separation unit to provide pure oxygen to reformer. The addition of oxygen leads to a partial combustion reaction that provides the heat for the reformer reaction. Unlike SMR, ATR does not require external natural gas combustion to heat the reformer. ATR also requires lower relative CO_2 capture costs than SMR because there is only a high-pressure, process-based emission stream. With more available data, it would be worth conducting future work to understand how the levelized cost of ATR-CCS evolves in a California market with 45Q and LCFS incentives.

On the other hand, NETL finds that coal and/or biomass gasification with CCS are more expensive than SMR-CCS, with levelized costs exceeding $3/kg. Biomass gasification with CCS could be worth exploring in a California market, given the negative carbon intensity of the production method and its impact on LCFS revenues, but it will likely still have a hard time competing with clean SMR production pathways.

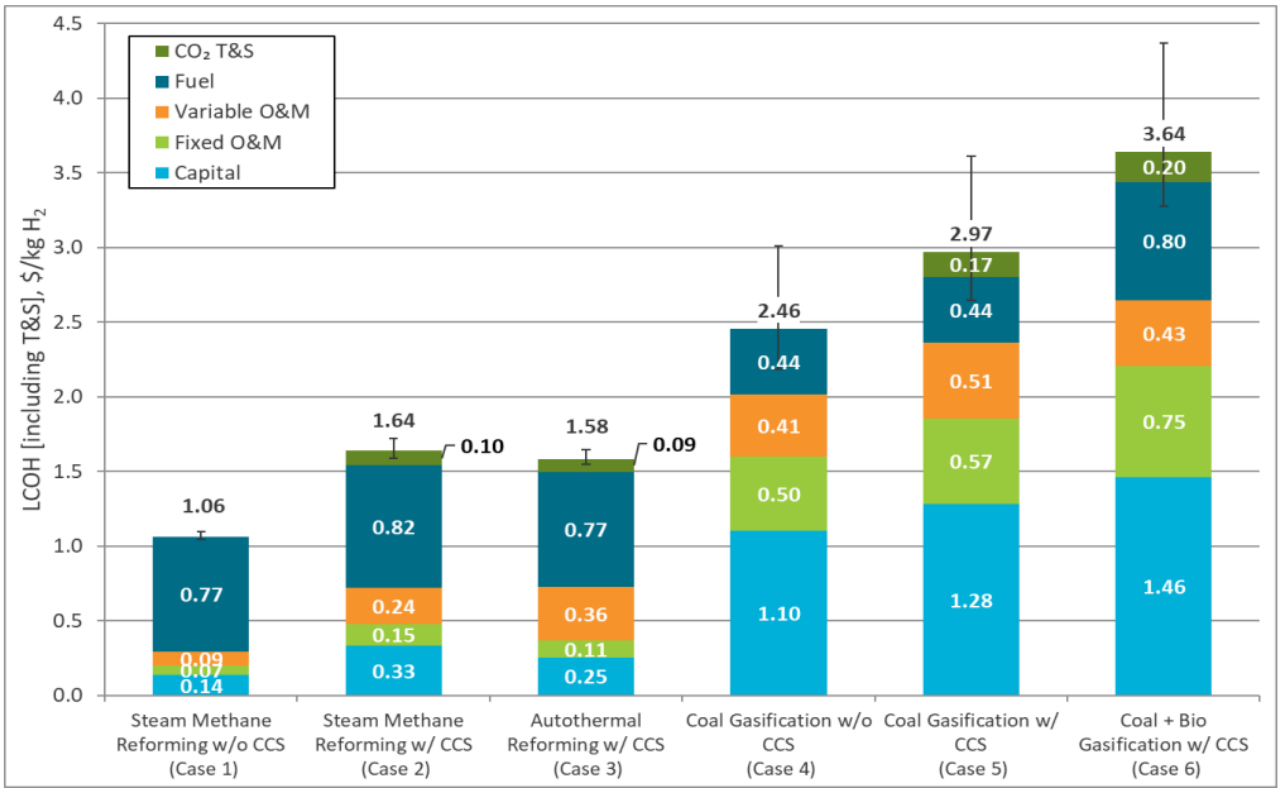

Figure 16: Levelized cost comparison of fossil-based hydrogen production methods (no subsidies).

Workstream 3 Conclusions

We model the financial viability of a 250 metric ton/day blue hydrogen (SMR-CCS) plant in Northern California. Our financial model calculates the LCOH of blue hydrogen under various scenarios, starting from a baseline scenario that does not include any federal or state subsidies.

Our key findings are as follows:

- Unsubsidized blue hydrogen is likely to be quite expensive in California, with unsubsidized LCOH at $3.59/kg. This can be attributed to higher natural gas prices in California as well as to our assumption that demand scales to capacity over ten years.
- Existing federal and state policies – the 45Q and LCFS – are key in making blue hydrogen more cost-competitive, by bringing down the LCOH by 50%, with LCFS and 45Q contributing to 2/3rd and 1/3rd of cost reductions, respectively.
- The proposed federal policies in the Build Back Better plan – the ITC or the PTC – are not better than the existing federal policy, i.e., 45Q. This indicates a need for more ambitious federal policies.
- In California, SMR-CCS hydrogen production is a lower cost solution than electrolysis from renewables in the near-term. It is worth further exploration to see if ATR-CCS is a lower cost clean hydrogen production solution in comparison to SMR-CCS.

We also find that the LCOH is quite sensitive to natural gas prices as well as to a low demand scenario.

Workstream 4: Combined feasibility analysis and recommended path forward

Agreed Scope of Work
Tie together the results of the first 3 workstreams and assess the top locations for a SMR hydrogen plant with CCS and onsite underground geologic storage in northern California.

Based on the combined results of workstreams 1-3 of this study, there are 7 sites in northern California that warrant further evaluation for a collocated SMR-CCS facility with a capacity of 250 metric ton per day. A facility of this size would meet the mid-case hydrogen demand scenario and provide enough hydrogen for between 167 and 500 refueling stations (depending on capacity).

There are a number of regulatory and commercial issues that will need to be addressed in addition to refining the technical specifications of this project.

We recommend the following next steps:

- Perform detailed subsurface site characterization of the 7 highgraded sites as outlined in Workstream 1.
- Conduct a thorough stakeholder analysis including in-person community engagements to futher evaluate the community acceptance of such a project
- Evaluate land ownership in more detail and commence discussions with land owners
- Refine technoeconomic model to include Shell proprietary data on CCS capture costs and other CAPEX, OPEX, and feedstock inputs.
- Work with legislators in Sacramento to enhance commercial attributes of CCS projects.
- Explore the potential for this project to be part of a hydrogen hub to leverage infrastructure and work with partners on the regulatory issues.

References

[1] Shell, "The Future of Hydrogen," 2017. [Online]. Available: https://www.shell.com/energy-and-innovation/new-energies/hydrogen/_jcr_content/par/keybenefits_150847174/link.stream/1496312627865/6a3564d61b9aff43e087972db5212be68d1fb2e8/shell-h2-study-new.pdf.

[2] EFI and Stanford University, "An Action Plant for Carbon Capture and Storage in California; Opportunities, Challenges, and Solution," Energy Futures Initiative and Stanford University Stanford Center for Carbon Storage, 2020.

[3] C. Callas, S. D. Saltzer, J. S. Davis, S. S. Hashemi, A. R. Kovscek, E. R. Okoroafor, G. Wen, M. D. Zoback and S. M. Benson, "Criteria and Workflow for Selecting Depleted Hydrocarbon Reservoirs for Carbon Storage," *Applied Energy,* 2022.

[4] M. Myer, K. Birkinshaw, L. T. Hope, M. Krebs and B. B. Blevins, "Carbon Sequestration Options for the West Coast States (CEC 500 -2007-005)," West Coast Regional Carbon Sequestration Partnership and California Energy Commission, 2007.

[5] C. Downey and J. P. Clinkenbeard, "Studies Impacting Geologic Carbon Sequestration Potential in California: Offshore Carbon Sequestration Potential, Sacramento Basin Salinity Investigation of Select Formations, Sacramento Basin Hydrocarbon Pool Size Distribution (CEC-500-2011-044)," California Energy Commission, 2011.

[6] T. W. Kim, C. Callas, S. D. Saltzer and A. R. Kovscek, "Assessment of oil and gas fields in California as potential CO2 storage sites," *International Journal of Greenhouse Gas Control,* 2022.

[7] California Division of Oil, Gas and Geothermal Resources (CA DOGGR), "California Oil and Gas Fields, Volume III – Northern California," California Department of Conservation, 1982.

[8] U.S. Geological Survey and California Geological Survey, "Quaternary Fault and Fold Database of the United States," [Online]. Available: https://www.usgs.gov/natural-hazards/earthquake-hazards/faults. [Accessed 8 June 2021].

[9] J. C. Long, J. T. Birkholzer, A. J. Mace and S. E. Brady, "Long-Term Viability of Underground Natural Gas Storage in California," California Council on Science and Technology, 2018.

[10] National Energy Technology Laboratory (NETL), "The National Carbon Sequestration Database (NATCARB)," National Energy Technology Laboratory, 2015.

[11] California Department of Conservation , "WELLSTAR database," [Online]. Available: https://app.powerbigov.us/view?r=eyJrIjoiNGQzZWU1N2QtNjNmYy00ODQyLWJlNDUtODBiYjg2MjYyYzIzIiwidCI6IjRjNTk4OGFlLTVhMDAtNDBlOC1iMDY1LWEwMTdmOWM5OTQ5NCJ9.

[12] T. C. V, "THE RELATION BETWEEN THE LOWERING OF THE PIEZOMETRIC SURFACE AND THE RATE AND DURATION OF DISCHARGE OF A WEll US ING GROUND WATER STORAGE," UNITED STATES DEPARTMENT OF THE INTERIOR GEOLOGICAL SURVEY WATER RESOURCES HYDRAULICS, 1935.

[13] E. W. Lemmon, I. H. Bell, M. L. Huber and M. O. McLinden, *Thermophysical Properties of Fluid Systems,* P. J. Linstrom and W. G. Mallard, Eds., Gaithersburg, MD: National Institute of Standards and Technology, 2021.

[14] M. D. Zoback, C. A. B. M. Barton, D. A. Castillo, T. Finkbeiner, B. R. Grollimund, D. B. Moos, P. Peska, C. D. Ward and D. Wiprut, "Determination of stress orientation and magnitude in deep wells," *International Journal of Rock Mechanics & Mining Sciences,* vol. 40, p. 1049–1076, 2003.

[15] L. Zeise and J. Blumenfeld, "CalEnviroscreen 4.0," California Office of Environmental Health Hazard Assessment (OEHHA), 2021. [Online]. Available: https://oehha.ca.gov/calenviroscreen/report/calenviroscreen-40.

[16] P. Sun, B. Young, A. Elgowainy, Z. Lu, M. Wang, B. Morelli and A. Hawkins, "Criteria Air Pollutants and Greenhouse Gas Emissions from Hydrogen Production in U.S. Steam Methane Reforming Facilitis," *Environmental Science and Technology,* pp. 7103-7113, 2019.

[17] C. W. Tessum, J. D. Hill and J. D. Marshall, "InMAP" A model for air pollution interventions," PLoS ONE, 2019.

[18] A. L. Goodkind, C. W. Tessum, J. S. Coggins, J. D. Hill and J. D. Marshall, "InMAP Source Receptor Matrix (ISRM) dataset (1.2.1) [Data set]," Zenodo, 2019.

[19] j. Liu, L. P. Clark, M. J. Bechle, A. Hajat, S. Y. Kim, L. Robinson, L. Sheppard, A. A. Szpiro and J. D. Marshall, "Disparities in Air Pollutionn Exposure in the United States by Race/Ethnicity and Income, 1990-2010," 2021.

[20] H. M. Lane, R. Morello-Frosch, J. D. Marshall and J. S. Apte, "Historical Redlining is Associated with Present-Day Air Pollution disparities in U.S. Cities," *Environmental Science & Technology Letters,* 2022.

[21] Parcelquest, [Online]. Available: https://www.parcelquest.com/.

[22] California Air Resources Board, "EMFAC2017 Emissions Inventory," 2-18. [Online]. Available: https://arb.ca.gov/emfac/emissions-inventory.

[23] California Air Resources Board, "Revised Draft 2020 Mobile Source Strategy," 2021.

[24] D.-Y. Lee, A. Elgowainy, A. Kotz, R. Vijayagopal and J. Marcinkoski, "ife-cycle implications of hydrogen fuel cell electric vehicle technology for medium- and heavy-duty trucks," *Journal of Power Sources,* vol. 393, 2018.

[25] California Air Resources Board, "Annual Evaluation of Fuel Cell Electric Vehicle Deployment and Hydrogen Fuel Station Network Development," 2021.

[26] Energy Futures Initiative and Stanford University, "An Action Plan for Carbon Capture and Storage in California: Opportunities, Challenges, and Solutions," 2020.

[27] G. Peridas, "Permitting Carbon Capture & Storage Projects in California," Lawrence Livermore National Laboratory, LLNL-TR-817425, 2021.

[28] J. Theis, "Cost Estimation Methodology for NETL Assessments of Power Plant Performance," National Energy Technology Laboratory, 2019.

[29] National Renewable Energy Laboratory, "H2A: Hydrogen Analysis Production Models," 2018. [Online]. Available: https://www.nrel.gov/hydrogen/h2a-production-models.html.

[30] National Petroleum Council, "Meeting the Dual Challenge: A Roadmap to At-Scale Deployment of Carbon Capture, Use, and Storage," 2019.

[31] Pacific Gas and Electric Company, "Gas RateFinder," 2021. [Online]. Available: https://www.pge.com/tariffs/GRF0721.pdf.

[32] Pacific Gas and Electric Company, "Electric Schedule B-20," 2021. [Online]. Available: https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHEDS_B-20.pdf.

[33] International Energy Agency, "Techno - Economic Evaluation of SMR Based Standalone (Merchant) Hydrogen Plant with CCS," 2017.

[34] Congressional Research Service, "The Tax Credit for Carbon Sequestration (Section 45Q)," 2021.

[35] California Air Resources Board, "LCFS Pathway Certified Carbon Intensities," 2021. [Online]. Available: https://ww2.arb.ca.gov/resources/documents/lcfs-pathway-certified-carbon-intensities.

[36] California Air Resources Board, "CA-GREET3.0 Lookup Table Pathways: Technical Support Documentation," 2018.

[37] J. Bracci, A. Brandt, S. Benson, G. Shrimali and S. Saltzer, "Pathways To Carbon Neutrality in California: The Hydrogen Opportunity," Stanford Center for Carbon Storage, 2022.

[38] E. Lewis, "Overview of Integrated Pathway Analyses to Meet the Hydrogen Energy Earthshot Goal," National Energy Technology Laboratory, 2021.

[39] California Office of Environmental Health Hazard Assessment (OEHHA), "Poverty Index," 2022.