ANGELES LINK PHASE 1
DEMAND STUDY TECHNICAL APPENDIX
FINAL REPORT – DECEMBER 2024

SoCalGas commissioned this Demand Study Technical Appendix from Accenture and EPRI. The analysis was conducted, and this report was prepared, collaboratively.

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Angeles Link Phase 1 Demand Study

Appendix A: Methodology and Key Assumptions

Overall Methodology

Methodology Approach

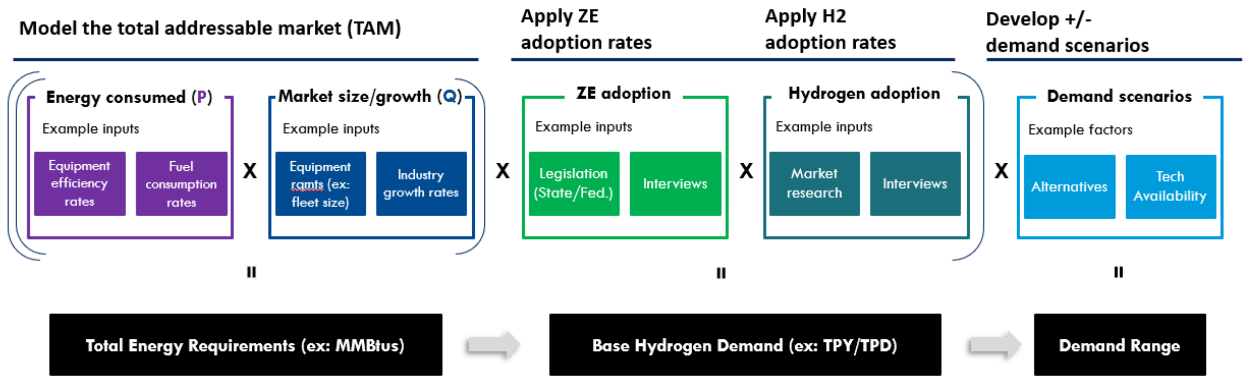
This section provides calculations, equations, and flow diagrams of calculations used in the model. The overall methodology approach explains the logic behind (1) what was modelled (2) how it was modelled.

At the onset of the demand study, subsectors (e.g. types of mobility, various hard-to-electrify industries) were prioritized for quantitative analysis based on currently known emission factors, current fuel usage, and a qualitative evaluation of potential for hydrogen in the subsector. The potential hydrogen demand for prioritized subsectors has been analyzed, with quantitative demand results outlined in this report. Subsectors not prioritized for quantitative analysis were not modelled, but potential opportunities for additional demand in these subsectors has been noted in this report.

Once subsectors were prioritized, the potential hydrogen demand was developed by modelling both the total addressable market for hydrogen as well as the adoption rates. This general methodology is outlined below, although specifics vary by sector and subsector:

1. Model Total Addressable Market (TAM) using current fuel usage.
    a. Determine industry growth rates.
    b. Define industry-specific characteristics (type of equipment used, efficiency rates and fuel consumption)
2. Apply Zero-Emission (ZE) adoption rates to TAM.
    a. Forecast transition to net-zero using current legislation and, when absent, align to State agency forecasts.
3. Apply hydrogen adoption rates to the ZE TAM
    a. Assess technical feasibility of each subsectors ability to convert, considering current industry equipment characteristics.
4. Develop demand scenarios.
    a. Define adoption scenarios through qualitative assessment of decarbonization alternatives, technology commercialization, and cost to adopt hydrogen.

Figure 1: Hydrogen Demand Methodology - Illustrative



Throughout the analysis process, targeted interviews were conducted with subject matter experts across industry, academia and government agencies to test these adoption inputs and assumptions, the model approach, and model outputs. Interviews were also held with potential hydrogen end-users to inform model assumptions and overall results.

Adoption Factors

Four primary factors were used to determine future hydrogen adoption across sectors: policy & legislation, technology feasibility, commercial availability, and business readiness. These factors reflect whether hydrogen is likely to be adopted in a specific subsector and to what extent hydrogen will be adopted versus alternatives.

Adoption factors have been quantified and inputted into the demand model where possible, with the different levels of adoption in 2045 and curves of the adoption rate from 2025-2045 reflecting the substantial variations in adoption factors between subsectors.

Table 1: Hydrogen Adoption Rate Driving Factors

Driving Factor	Description
Policy and Legislation	Policy and regulatory mandates, where they exist, compel a transition to zero-carbon technologies, while financial incentives reduce the cost of transitioning to hydrogen.
Technology Feasibility	Hydrogen adoption is conditional on its technical and operational feasibility in end-use applications.
Commercial Availability	Hydrogen demand volume depends on commercial availability and cost of hydrogen technologies compared with other available technologies.
Business Readiness	Equipment lifespan, retrofit and upgrade schedules, and other operational factors can impact a business's readiness to adopt a new technology.

Notable References

Several data sets and reports were referenced in the creation of the Demand Study analysis. Several interviews and peer reviews were conducted as well to further understand existing data sets and reports, as well as to validate preliminary findings from the Demand Study. Some of the key data sets and documents referenced for the Demand Study were as follows:

- **CARB EMFAC Database** – Used to determine current and forecasted vehicle fleet sizes in SoCalGas service territory, by application, from 2025-2045, including vehicle miles traveled (VMT) and fuel consumption rates. This database includes information that was used for 54 on-road vehicle applications, 107 off-road vehicle applications, 31 commercial harbor craft applications, and dozens of maritime vessels.[1]
- **CARB 2022 Scoping Plan** – Containing several assumptions on vehicle characteristics, lifespans, and the future of hydrogen and battery technologies

1 California Air Resources Board. "Emissions Inventory". https://arb.ca.gov/emfac/emissions-inventory/

across sub-sectors.[2]

- **U.S. National Clean Hydrogen Strategy and Roadmap report –** Contained useful information on timing and size of adoption[3]
- **U.S. Department of Energy Clean Hydrogen Pathways for Commercial Liftoff report –** Provided various pathways to clean hydrogen adoption in U.S., covering various opportunities and incentive programs[4]
- **EIA Power and Industrials Data –** Database contains various datasets on current natural gas consumption across power and industrial sectors used as base for analysis[5]
- **California Energy Commission Fueling Station GIS** – Leveraged to determine current fueling station locations and to forecast possible hydrogen fueling station locations in the future.[6]
- **UC Davis Analysis** – Including interviews and analysis such as California Hydrogen Analysis Project: The Future Role of Hydrogen in a Carbon-Neutral California.[7]
- **UC Irvine Analysis** – Including interviews and analysis such as Roadmap for the Deployment and Buildout of Renewable Hydrogen Production Plants in California.[8]
- **NREL Analysis** – Including interviews and analysis such as The Technical and

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[2] California Air Resources Board. "2022 Scoping Plan Documents." https://ww2.arb.ca.gov/our-work/programs/ab-32-climate-change-scoping-plan/2022-scoping-plan-documents

[3] U.S. Department of Energy. "U.S. National Clean Hydrogen Strategy and Roadmap." (June 2023). https://www.hydrogen.energy.gov/pdfs/us-national-clean-hydrogen-strategy-roadmap.pdf

[4] U.S. Department of Energy. "The Pathway to Clean Hydrogen Commercial Liftoff". (March 2023). https://liftoff.energy.gov/clean-hydrogen/.

[5] Homepage - U.S. Energy Information Administration (EIA)

[6] CalOES GIS Data Management. "CA Energy Commission - Gas Stations" CA Governor's Office of Emergency Services. (July 2, 2019). https://hub.arcgis.com/datasets/ec575b2693f64199866bc18744d232fe/explore

[7] UC Davis Institute of Transportation Studies. "California Hydrogen Analysis Project: The Future Role of Hydrogen in a Carbon-Neutral California Final Synthesis Modeling Report". (April 19, 2023). https://escholarship.org/uc/item/27m7g841

[8] UC Irvine Advanced Power and Energy Program. " Roadmap for the Deployment and Buildout of Renewable Hydrogen Production Plants in California". (June 2020). https://www.apep.uci.edu/PDF_White_Papers/Roadmap_Renewable_Hydrogen_Production-UCI_APEP-CEC.pdf

Economic Potential of the H2@Scale Concept within the United States.[9]

- **Argonne National Labs Models** – Has several reports and models which were leveraged to determine TCO for various on-road vehicle types. Models include the BEAN[10] and Autonomie Vehicle System Simulation Tool.
- **Air Emissions Inventory Reports** – From the Port of Los Angeles, Port of Long Beach, and Los Angeles World Airports, containing some information on vehicle fleet sizes, plans for achieving zero emissions vehicles, vehicle retirement rates, and usage characteristics.[11, 12, 13]

[9] Ruth, Mark F., et al. "The Technical and Economic Potential of the H2@Scale Concept within the United States". National Renewable Energy Laboratories. (October 2020). https://www.nrel.gov/docs/fy21osti/77610.pdf

[10] As of the publishing of this report, the BEAN model is now referred to as TechScape.

[11] Starcrest Consulting Group, LLC. "Inventory of Air Emissions for Calendar Year 2021". (September 2022). https://kentico.portoflosangeles.org/getmedia/f26839cd-54cd-4da9-92b7-a34094ee75a8/2021_air_emissions_inventory

[12] Port of Long Beach. "Emissions Inventory". (2023). https://polb.com/environment/air/#emissions-inventory

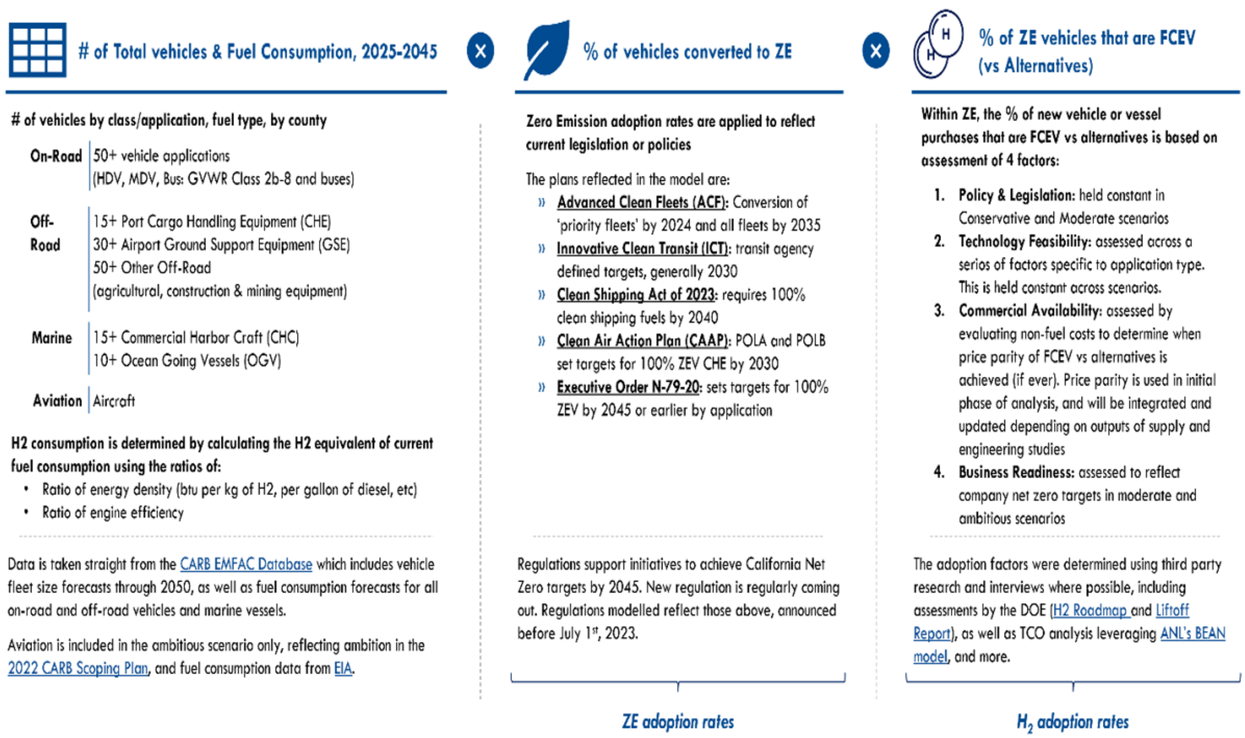
[13] Los Angeles World Airports. "LAX Air Quality & Source Apportionment Study". (June 2013). https://www.lawa.org/lawa-environment/lax/lax-air-quality-and-source-apportionment-study

Mobility

Methodology

Hydrogen demand for the mobility sector in SoCalGas service territory is modelled by multiplying critical factors together: total number of vehicles and fuel consumption (2025-2045), the percent of vehicles converted to ZEVs, and the percentage of ZE vehicles that are FCEV (vs alternatives). Each of these factors was either sourced from reference material or calculated using various assumptions as defined below.

Figure *2*: Mobility Sector - High-Level Modelling Methodology



Total Addressable market

<u>Fleet Sizes and Forecasts</u>

CARB forecasts vehicle populations across the State of California through 2050 in their EMFAC Emissions Database.[14] This data is shown by county, by fuel type, as well as by

[14] https://arb.ca.gov/emfac/emissions-inventory/

application type for on-road and off-road vehicles (including for marine vessels as well, though the number of vessel engines rather than the # of vessels is usually reflected).

The vehicle (and vessel) forecasts listed by EMFAC were utilized in the Angeles Link Phase 1 Demand Study without modification in order to represent total vehicle population forecasts. While the database includes some vehicle forecasts by type (such as gasoline, diesel, or battery vehicles), these breakdowns were independently calculated. However, where ZEVs exist today (2025, the starting year of the model), these factors were taken into account as starting points for the ZEV vehicle populations.

EMFAC lists many vehicle applications and the following vehicle types were taken into account for the AL Phase 1 Demand Study. Additionally, some assumptions were made at an aggregate level, and some outputs were aggregated as well—the following table lists some categorizations for these groupings.

Table *2*: List of Modelled Vehicles and Vessels

Sub-Sector	Type	H2 Adoption Rate Category	EMFAC202x Vehicle Class
On-Road	Bus	Other Buses	SBUS
On-Road	Bus	Other Buses	OBUS
On-Road	Bus	Other Buses	All Other Buses
On-Road	Bus	Transit Bus / Motor Coach	UBUS
On-Road	Bus	Transit Bus / Motor Coach	Motor Coach
On-Road	HDV	Class 7-8 Day Cab Tractor	T7 CAIRP Class 8
On-Road	HDV	Class 7-8 Day Cab Tractor	T7 NNOOS Class 8
On-Road	HDV	Class 7-8 Day Cab Tractor	T7 NOOS Class 8
On-Road	HDV	Class 7-8 Day Cab Tractor	T7 Tractor Class 8
On-Road	HDV	Class 8	T7 Public Class 8
On-Road	HDV	Class 8	T7 Utility Class 8
On-Road	HDV	Class 8	T7IS
On-Road	HDV	Class 8 Drayage	T7 Other Port Class 8
On-Road	HDV	Class 8 Drayage	T7 POAK Class 8

Sub-Sector	Type	H2 Adoption Rate Category	EMFAC202x Vehicle Class
On-Road	HDV	Class 8 Drayage	T7 POLA Class 8
On-Road	HDV	Class 8 Sleeper Cab Tractor	T7 NNOOS Class 8
On-Road	HDV	Class 8 Sleeper Cab Tractor	T7 NOOS Class 8
On-Road	HDV	Class 8 Sleeper Cab Tractor	T7 Tractor Class 8
On-Road	HDV	Class 8 Vocational	T7 SWCV Class 8
On-Road	HDV	Class 8 Vocational	T7 Single Concrete/Transit Mix
On-Road	HDV	Class 8 Vocational	T7 Single Dump Class 8
On-Road	HDV	Class 8 Vocational	T7 Single Other Class 8
On-Road	LDV	Passenger	LDA
On-Road	LDV	Passenger	LDT1
On-Road	LDV	Passenger	LDT2
On-Road	LDV	Passenger	MDV
On-Road	MDV	Class 2b-3	LHD1
On-Road	MDV	Class 2b-3	LHD2
On-Road	MDV	Class 4	T6 Public Class 4
On-Road	MDV	Class 4	T6 CAIRP Class 4
On-Road	MDV	Class 4	T6 CAIRP Class 5
On-Road	MDV	Class 4	T6 Instate Other Class 4
On-Road	MDV	Class 4	T6 Instate Other Class 5
On-Road	MDV	Class 4	T6 OOS Class 4
On-Road	MDV	Class 4 Delivery	T6 Instate Delivery Class 4
On-Road	MDV	Class 5	T6 Public Class 5
On-Road	MDV	Class 5	T6 Utility Class 5
On-Road	MDV	Class 5	T6 OOS Class 5
On-Road	MDV	Class 5 Delivery	T6 Instate Delivery Class 5
On-Road	MDV	Class 6	T6 Public Class 6
On-Road	MDV	Class 6	T6 Utility Class 6
On-Road	MDV	Class 6	T6 CAIRP Class 6
On-Road	MDV	Class 6	T6 Instate Other Class 6
On-Road	MDV	Class 6	T6 Instate Tractor Class 6
On-Road	MDV	Class 6	T6 OOS Class 6
On-Road	MDV	Class 6	T6TS
On-Road	MDV	Class 6 Delivery	T6 Instate Delivery Class 6

Sub-Sector	Type	H2 Adoption Rate Category	EMFAC202x Vehicle Class
On-Road	MDV	Class 7	T6 Public Class 7
On-Road	MDV	Class 7	T6 Utility Class 7
On-Road	MDV	Class 7	T6 Instate Other Class 7
On-Road	MDV	Class 7	T6 Instate Tractor Class 7
On-Road	MDV	Class 7 Delivery	T6 Instate Delivery Class 7
On-Road	MDV	Class 7-8 Day Cab Tractor	T6 CAIRP Class 7
On-Road	MDV	Class 7-8 Day Cab Tractor	T6 OOS Class 7
On-Road	MDV	Motor Home	MH
Off-Road	CHE	Container Handling Equipment	Cargo Handling Equipment - Port Container Handling Equipment
Off-Road	CHE	Excavator	Cargo Handling Equipment - Port Excavator
Off-Road	CHE	Forklift	Cargo Handling Equipment - Port Forklift
Off-Road	CHE	Port Crane	Cargo Handling Equipment - Port Crane
Off-Road	CHE	Port Crane	Cargo Handling Equipment - Port STS Crane
Off-Road	CHE	Port HDV	Cargo Handling Equipment - Port Rail Car Mover
Off-Road	CHE	Port HDV	Cargo Handling Equipment - Port Tractors/Loaders/Backhoes
Off-Road	CHE	Port MDV	Cargo Handling Equipment - Port Electric Pallet Jack
Off-Road	CHE	Port MDV	Cargo Handling Equipment - Port Lift
Off-Road	CHE	Port MDV	Cargo Handling Equipment - Port Other
Off-Road	CHE	Port MDV	Cargo Handling Equipment - Port Skid Steer Loaders
Off-Road	CHE	RTG Crane	Cargo Handling Equipment - Port RTG Crane
Off-Road	CHE	Terminal Tractor	Cargo Handling Equipment - Port AGV
Off-Road	CHE	Terminal Tractor	Cargo Handling Equipment - Port Tractor
Off-Road	CHE	Terminal Tractor	Cargo Handling Equipment - Port Truck
Off-Road	CHE	Terminal Tractor	Cargo Handling Equipment - Port Yard Truck

Sub-Sector	Type	H2 Adoption Rate Category	EMFAC202x Vehicle Class
Off-Road	GSE	A/C Tug	Airport Ground Support - Misc - A/C Tug Wide Body
Off-Road	GSE	A/C Tug	Airport Ground Support - Misc - A/C Tug Narrow Body
Off-Road	GSE	A/C Tug	Airport Ground Support - A/C TugWide Body
Off-Road	GSE	A/C Tug	Airport Ground Support - A/C TugNarrow Body
Off-Road	GSE	Cart	Airport Ground Support - Misc - Air Start Unit
Off-Road	GSE	Cart	Airport Ground Support - Misc - Other
Off-Road	GSE	Cart	Airport Ground Support - Misc - Air Conditioner
Off-Road	GSE	Cart	Airport Ground Support - Misc - Cart
Off-Road	GSE	Cart	Airport Ground Support - Misc - Lav Cart
Off-Road	GSE	Generator	Airport Ground Support - Misc - Ground Power Unit
Off-Road	GSE	Generator	Airport Ground Support - Misc - Generator
Off-Road	GSE	HD Truck / Tractor	Airport Ground Support - Misc - Hydrant Truck
Off-Road	GSE	HD Truck / Tractor	Airport Ground Support - Misc - Catering Truck
Off-Road	GSE	HD Truck / Tractor	Airport Ground Support - Misc - Cargo Tractor
Off-Road	GSE	LD Truck / Tractor	Airport Ground Support - Misc - Sweeper
Off-Road	GSE	LD Truck / Tractor	Airport Ground Support - Misc - Water Truck
Off-Road	GSE	LD Truck / Tractor	Airport Ground Support - Baggage Tug
Off-Road	GSE	LD Truck / Tractor	Airport Ground Support - Cargo Tractor
Off-Road	GSE	LD Truck / Tractor	Airport Ground Support - Passenger Stand
Off-Road	GSE	LD Truck / Tractor	Airport Ground Support - Misc - Deicer
Off-Road	GSE	LD Truck / Tractor	Airport Ground Support - Misc - Fuel Truck

Sub-Sector	Type	H2 Adoption Rate Category	EMFAC202x Vehicle Class
Off-Road	GSE	Loaders / Lifts	Airport Ground Support - Misc - Cargo Loader
Off-Road	GSE	Loaders / Lifts	Airport Ground Support - Misc - Belt Loader
Off-Road	GSE	Loaders / Lifts	Airport Ground Support - Misc - Lift
Off-Road	GSE	Loaders / Lifts	Airport Ground Support - Cargo Loader
Off-Road	GSE	Loaders / Lifts	Airport Ground Support - Other
Off-Road	GSE	Loaders / Lifts	Airport Ground Support - Misc - Passenger Stand
Off-Road	GSE	Loaders / Lifts	Airport Ground Support - Misc - Forklift
Off-Road	GSE	Loaders / Lifts	Airport Ground Support - Lift
Off-Road	GSE	Loaders / Lifts	Airport Ground Support - Forklift
Off-Road	GSE	Loaders / Lifts	Airport Ground Support - Belt Loader
Off-Road	GSE	MD Truck / Tractor	Airport Ground Support - Misc - Bobtail
Off-Road	GSE	MD Truck / Tractor	Airport Ground Support - Misc - Baggage Tug
Off-Road	GSE	MD Truck / Tractor	Airport Ground Support - Misc - Lav Truck
Off-Road	GSE	MD Truck / Tractor	Airport Ground Support - Bobtail
Off-Road	GSE	MD Truck / Tractor	Airport Ground Support - Misc - Service Truck
Off-Road	GSE	MD Truck / Tractor	Airport Ground Support - Misc - Maint. Truck
Off-Road	Other-Off Road	ATVs	Agricultural - ATVs
Off-Road	Other-Off Road	Digging	Construction and Mining - Trenchers
Off-Road	Other-Off Road	Digging	Construction and Mining - Misc - Trenchers
Off-Road	Other-Off Road	Digging	Construction and Mining - Misc - Excavators

Sub-Sector	Type	H2 Adoption Rate Category	EMFAC202x Vehicle Class
Off-Road	Other-Off Road	Forklifts	Agricultural - Forklifts
Off-Road	Other-Off Road	Forklifts	Construction and Mining - Misc - Rough Terrain Forklifts
Off-Road	Other-Off Road	Forklifts	Construction and Mining - Rough Terrain Forklifts
Off-Road	Other-Off Road	Handheld	Construction and Mining - Misc - Concrete/Industrial Saws
Off-Road	Other-Off Road	Handheld	Construction and Mining - Misc - Plate Compactors
Off-Road	Other-Off Road	Handheld	Construction and Mining - Misc - Tampers/Rammers
Off-Road	Other-Off Road	Heavy Ag	Agricultural - Forage & Silage Harvesters
Off-Road	Other-Off Road	Heavy Ag	Agricultural - Combine Harvesters
Off-Road	Other-Off Road	Heavy Ag	Agricultural - Cotton Pickers
Off-Road	Other-Off Road	Heavy Mining & Construction	Construction and Mining - Rubber Tired Dozers
Off-Road	Other-Off Road	Heavy Mining & Construction	Construction and Mining - Scrapers
Off-Road	Other-Off Road	Heavy Mining & Construction	Construction and Mining - Off-Highway Tractors

Sub-Sector	Type	H2 Adoption Rate Category	EMFAC202x Vehicle Class
Off-Road	Other-Off Road	Heavy Mining & Construction	Construction and Mining - Misc - Surfacing Equipment
Off-Road	Other-Off Road	Heavy Stationary Equipment	Construction and Mining - Bore/Drill Rigs
Off-Road	Other-Off Road	Heavy Stationary Equipment	Construction and Mining - Cranes
Off-Road	Other-Off Road	Heavy Stationary Equipment	Construction and Mining - Misc - Cranes
Off-Road	Other-Off Road	Heavy Stationary Equipment	Construction and Mining - Misc - Bore/Drill Rigs
Off-Road	Other-Off Road	Heavy Stationary Equipment	Construction and Mining - Misc - Crushing/Proc. Equipment
Off-Road	Other-Off Road	Light Ag	Agricultural - Bale Wagons (Self Propelled)
Off-Road	Other-Off Road	Light Ag	Agricultural - Hay Squeeze/Stack Retriever
Off-Road	Other-Off Road	Light Ag	Agricultural - Other Harvesters
Off-Road	Other-Off Road	Light Ag	Agricultural - Swathers/Windrowers/Hay Conditioners
Off-Road	Other-Off Road	Light Ag	Agricultural - Agricultural Tractors
Off-Road	Other-Off Road	Light Ag	Agricultural - Nut Harvester

Sub-Sector	Type	H2 Adoption Rate Category	EMFAC202x Vehicle Class
Off-Road	Other-Off Road	Light Ag	Agricultural - Construction Equipment
Off-Road	Other-Off Road	Light Ag	Agricultural - Balers (Self Propelled)
Off-Road	Other-Off Road	Light Ag	Agricultural - Sprayers/Spray Rigs
Off-Road	Other-Off Road	Light Mining & Construction	Construction and Mining - Skid Steer Loaders
Off-Road	Other-Off Road	Light Mining & Construction	Construction and Mining - Misc - Skid Steer Loaders
Off-Road	Other-Off Road	Light Stationary Equipment	Construction and Mining - Misc - Signal Boards
Off-Road	Other-Off Road	Light Stationary Equipment	Construction and Mining - Misc - Cement And Mortar Mixers
Off-Road	Other-Off Road	Medium Mining & Construction	Construction and Mining - Rubber Tired Loaders
Off-Road	Other-Off Road	Medium Mining & Construction	Construction and Mining - Crawler Tractors
Off-Road	Other-Off Road	Medium Mining & Construction	Construction and Mining - Misc - Tractors/Loaders/Backhoes
Off-Road	Other-Off Road	Medium Mining & Construction	Construction and Mining - Excavators
Off-Road	Other-Off Road	Medium Mining & Construction	Construction and Mining - Misc - Rubber Tired Loaders

Sub-Sector	Type	H2 Adoption Rate Category	EMFAC202x Vehicle Class
Off-Road	Other-Off Road	Medium Mining & Construction	Construction and Mining - Misc - Other
Off-Road	Other-Off Road	Medium Mining & Construction	Construction and Mining - Other
Off-Road	Other-Off Road	Medium Mining & Construction	Construction and Mining - Tractors/Loaders/Backhoes
Off-Road	Other-Off Road	Medium Mining & Construction	Construction and Mining - Misc - Dumpers/Tenders
Off-Road	Other-Off Road	Off Highway Trucks	Construction and Mining - Off-Highway Trucks
Off-Road	Other-Off Road	Paving	Construction and Mining - Surfacing Equipment
Off-Road	Other-Off Road	Paving	Construction and Mining - Paving Equipment
Off-Road	Other-Off Road	Paving	Construction and Mining - Pavers
Off-Road	Other-Off Road	Paving	Construction and Mining - Graders
Off-Road	Other-Off Road	Paving	Construction and Mining - Rollers
Off-Road	Other-Off Road	Paving	Construction and Mining - Misc - Asphalt Pavers
Off-Road	Other-Off Road	Paving	Construction and Mining - Misc - Rollers

Sub-Sector	Type	H2 Adoption Rate Category	EMFAC202x Vehicle Class
Off-Road	Other-Off Road	Paving	Construction and Mining - Misc - Paving Equipment
Off-Road	Other-Off Road	Paving	Construction and Mining - Misc - Pavers
Marine	CHC	Barge / Dredge - AE	Commercial Harbor Craft - AE - Barge-Bunker
Marine	CHC	Barge / Dredge - AE	Commercial Harbor Craft - AE - Barge-Other
Marine	CHC	Barge / Dredge - AE	Commercial Harbor Craft - AE - Barge-Towed Petrochemical
Marine	CHC	Barge / Dredge - AE	Commercial Harbor Craft - AE - Dredge
Marine	CHC	Barge / Dredge - ME	Commercial Harbor Craft - ME - Dredge
Marine	CHC	Commercial Fishing - AE	Commercial Harbor Craft - AE - Commercial Fishing
Marine	CHC	Commercial Fishing - AE	Commercial Harbor Craft - AE - Commercial Passenger Fishing
Marine	CHC	Commercial Fishing - ME	Commercial Harbor Craft - ME - Commercial Fishing
Marine	CHC	Commercial Fishing - ME	Commercial Harbor Craft - ME - Commercial Passenger Fishing
Marine	CHC	Excursion - AE	Commercial Harbor Craft - AE - Excursion
Marine	CHC	Excursion - ME	Commercial Harbor Craft - ME - Excursion
Marine	CHC	Ferry - AE	Commercial Harbor Craft - AE - Ferry-Catamaran
Marine	CHC	Ferry - AE	Commercial Harbor Craft - AE - Ferry-Monohull
Marine	CHC	Ferry - AE	Commercial Harbor Craft - AE - Ferry-Short Run
Marine	CHC	Ferry - ME	Commercial Harbor Craft - ME - Ferry-Catamaran
Marine	CHC	Ferry - ME	Commercial Harbor Craft - ME - Ferry-Monohull

Sub-Sector	Type	H2 Adoption Rate Category	EMFAC202x Vehicle Class
Marine	CHC	Ferry - ME	Commercial Harbor Craft - ME - Ferry-Short Run
Marine	CHC	Other - AE	Commercial Harbor Craft - AE - Crew/Supply
Marine	CHC	Other - AE	Commercial Harbor Craft - AE - Pilot Boat
Marine	CHC	Other - AE	Commercial Harbor Craft - AE - Research Boat
Marine	CHC	Other - AE	Commercial Harbor Craft - AE - Work Boat
Marine	CHC	Other - ME	Commercial Harbor Craft - ME - Crew/Supply
Marine	CHC	Other - ME	Commercial Harbor Craft - ME - Pilot Boat
Marine	CHC	Other - ME	Commercial Harbor Craft - ME - Research Boat
Marine	CHC	Other - ME	Commercial Harbor Craft - ME - Work Boat
Marine	CHC	Tugboat - AE	Commercial Harbor Craft - AE - Barge-ATB
Marine	CHC	Tugboat - AE	Commercial Harbor Craft - AE - Tugboat-ATB
Marine	CHC	Tugboat - AE	Commercial Harbor Craft - AE - Tugboat-Escort/Ship Assist
Marine	CHC	Tugboat - AE	Commercial Harbor Craft - AE - Tugboat-Push/Tow
Marine	CHC	Tugboat - ME	Commercial Harbor Craft - ME - Tugboat-ATB
Marine	CHC	Tugboat - ME	Commercial Harbor Craft - ME - Tugboat-Escort/Ship Assist
Marine	CHC	Tugboat - ME	Commercial Harbor Craft - ME - Tugboat-Push/Tow
Marine	OGV	Auto Carrier	Ocean Going Vessels - Auto Carrier
Marine	OGV	Bulk	Ocean Going Vessels - Bulk
Marine	OGV	Bulk	Ocean Going Vessels - Bulk - Heavy Load

Sub-Sector	Type	H2 Adoption Rate Category	EMFAC202x Vehicle Class
Marine	OGV	Bulk	Ocean Going Vessels - Bulk - Self Discharging
Marine	OGV	Container	Ocean Going Vessels - Container - 1000
Marine	OGV	Container	Ocean Going Vessels - Container - 2000
Marine	OGV	Container	Ocean Going Vessels - Container - 3000
Marine	OGV	Container	Ocean Going Vessels - Container - 4000
Marine	OGV	Container	Ocean Going Vessels - Container - 5000
Marine	OGV	Container	Ocean Going Vessels - Container - 6000
Marine	OGV	Container	Ocean Going Vessels - Container - 7000
Marine	OGV	Container	Ocean Going Vessels - Container - 8000
Marine	OGV	Container	Ocean Going Vessels - Container - 9000
Marine	OGV	Container	Ocean Going Vessels - Container - 10000
Marine	OGV	Container	Ocean Going Vessels - Container - 11000
Marine	OGV	Container	Ocean Going Vessels - Container - 12000
Marine	OGV	Container	Ocean Going Vessels - Container - 13000
Marine	OGV	Container	Ocean Going Vessels - Container - 14000
Marine	OGV	Container	Ocean Going Vessels - Container - 15000
Marine	OGV	Container	Ocean Going Vessels - Container - 16000
Marine	OGV	Container	Ocean Going Vessels - Container - 17000
Marine	OGV	Container	Ocean Going Vessels - Container - 19000
Marine	OGV	Container	Ocean Going Vessels - Container - 20000
Marine	OGV	Container	Ocean Going Vessels - Container - 23000
Marine	OGV	Cruise	Ocean Going Vessels - Cruise
Marine	OGV	General Cargo	Ocean Going Vessels - General Cargo
Marine	OGV	Miscellaneous	Ocean Going Vessels - Miscellaneous

Sub-Sector	Type	H2 Adoption Rate Category	EMFAC202x Vehicle Class
Marine	OGV	Reefer	Reefer
Marine	OGV	RoRo	Ocean Going Vessels - RoRo
Marine	OGV	Tanker	Ocean Going Vessels - Tanker - Aframax
Marine	OGV	Tanker	Ocean Going Vessels - Tanker - Chemical
Marine	OGV	Tanker	Ocean Going Vessels - Tanker - Handysize
Marine	OGV	Tanker	Ocean Going Vessels - Tanker - Panamax
Marine	OGV	Tanker	Ocean Going Vessels - Tanker - Suezmax
Marine	OGV	Tanker	Ocean Going Vessels - Tanker - VLCC

Note: H2 Adoption Rate Category reflects the application groupings that were utilized so that similar applications could be treated the same. The EMFAC202x Vehicle Class is the raw name of the vehicle application as defined by EMFAC. See EMFAC Vehicle Class Categorization.[15]

There are few modifications that were made to the list of EMFAC vehicle applications:

1. Motorcycles (MCY) were omitted from analysis.
2. Power Take Off vehicles (PTO) were omitted from analysis.
3. Class 8 Tractors were split out into Class 8 Day Cab Tractors and Class 8 Sleeper Cab Tractors in the ratios defined by CARB in their 2022 Scoping Plan Appendix.[16]
    a. Ratio of 1:9 in-state registered vehicles were considered Sleeper Cabs (vs Day Cabs)
    b. Ratio of 8:9 out-of-state registered vehicles were considered Sleeper Cabs (vs Day Cabs)

The data is available by county, so forecasts were taken by application for 2025-2045 for the 11 counties which generally reflect SoCalGas service territory.

[15] https://ww2.arb.ca.gov/sites/default/files/2021-03/emfac2021_volume_3_technical_document.pdf
[16] https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2022/acf22/appf.pdf

EMFAC does not forecast aircraft populations or jet fuel consumption, so these were modelled separately. Information on current jet fuel consumption (used as a proxy for what may be displaced by hydrogen fuel cell aircraft) was taken from EIA.[17] Additionally, data was filtered to reflect flight passenger traffic through the busiest airports in SoCalGas service territory: Los Angeles, Burbank, Long Beach, Ontario, and Orange County.[18]

Hydrogen Fuel Consumption Rates

Hydrogen fuel consumption rates were determined by modelling the hydrogen equivalent of current diesel or gasoline consumption. The EMFAC data set was also utilized to pull current average diesel or gasoline fuel consumption by vehicle application for the vehicles in SoCalGas service territory. For this, 2019 values were utilized (to reflect the most recent year without COVID impacts). For most applications—on-road, off-road, and marine—the vast majority of fuel consumption is diesel, so the hydrogen equivalent to diesel consumption was calculated. If a vehicle listed both diesel and gasoline consumption, generally the diesel equivalent figures were used.

To calculate potential hydrogen consumption rates, a conversion was calculated based on energy density ratios and typical engine efficiency ratios. While some of these figures, such as engine efficiency, may vary by application or individual vehicle, these broad industry averages were leveraged as representative of a typical vehicle.

[17] https://www.eia.gov/state/seds/data.php?incfile=/state/seds/sep_fuel/html/fuel_jf.html&sid=CA
[18] https://industry.visitcalifornia.com/research/passenger-traffic?a1=LAX

Table 3: Fuel Efficiency Ratios

Metric	Units	Value
BTU per kg Hydrogen[19]	BTU / kg H2	134,510
BTU per gallon Gasoline[20]	BTU / gallon gasoline	117,500
BTU per gallon Diesel[21]	BTU / gallon diesel	137,500
Polymer Electrolyte Membrane Fuel Cell Efficiency[22]	%	50%
Diesel Engine Efficiency[23]	%	50%
Gasoline Engine Efficiency[24]	%	20%

Finally, to account for advances in fuel cell efficiency (i.e., that fuel cells fuel economy will improve), a conservative assumption of 0.5% efficiency improvement per year was modelled. The way this is modelled yields an important implicit assumption: that vehicle miles travelled (VMT) is assumed to be constant by vehicle application through 2045 (for all on-road vehicles).

Assumptions (ZEV adoption Rates)

To determine the theoretical ceiling for the amount of hydrogen fuel cell vehicles and vessels, existing legislation was considered to identify how quickly ZEVs would replace their ICE counterparts. Legislation generally exists for the mobility sub-sectors modelled.

Importantly, it should be noted that legislation almost unanimously impacts the sales of new vehicles and generally does not force early retirement of vessels. Therefore, vehicle retirement rates are also a critical factor in determining the population forecasts of ZEVs in California. The following assumptions were made regarding vehicle retirement rates:

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[19] https://afdc.energy.gov/fuels/properties
[20] Ibid
[21] Ibid
[22] https://www.energy.gov/eere/fuelcells/articles/fuel-cells-fact-sheet
[23] DOE Hydrogen and Fuel Cells Program Record 19006: Hydrogen Class 8 Long Haul Truck Targets
[24] https://www.anl.gov/article/combining-gas-and-diesel-engines-could-yield-best-of-both-worlds

Table 4: On-Road Vehicle Retirement Rates

Vehicle Type	Retirement Rate
Heavy Duty Vehicles	17 years[25]
Medium Duty Vehicles	17 years[26]
Light Duty Vehicles	17 years[27]
Buses	12 years[28]

Table 5: Off-Road Vehicle Retirement Rates

Vehicle Type	Retirement Rate
Ground Support Equipment	15-19 years[29]
Cargo Handling Equipment	10-20 years[30]
Other Off-Road Equipment	5-20 years[31] [32]
Marine Vessels (Commercial Harbor Craft)	15 years[33]
Marine Vessels (Ocean Going Vessels)	n/a[34]

Note: For some vehicle applications generalizations of estimates were used given lack of readily available data.

Since legislative requirements are fixed reference points, their impacts are held constant across all modelled scenarios (i.e., the number of ZEVs do not change across

[25] CARB 2022 Scoping Plan Appendix H, Table H-1: https://ww2.arb.ca.gov/sites/default/files/2022-12/2022-sp-appendix-h-ab-32-ghg-inventory-sector-modeling.pdf
[26] Ibid
[27] Ibid
[28] Ibid
[29] https://www.aviationpros.com/gse/article/21256272/state-of-the-industry
[30] https://cleanairactionplan.org/download/239/cargo-handling-equipment/5192/2021-che-feasibility-assessment-report-final.pdf
[31] https://thompsontractor.com/blog/average-lifespan-of-common-construction-equipment/
[32] Life Expectancy of Used Tractors | Fort Gibson, OK
[33] Commercial Harbor Craft Factsheets | California Air Resources Board
[34] Ocean Going Vessels (OGV) were modelled slightly differently to other vehicle and vessel types. For OGVs, a percentage of the total vessel population converting to ZEV was modelled instead of new vessel replacement rate considering the data available.

the Conservative, Moderate, or Ambitious scenarios modelled, only the composition of the ZEVs—BEV, FCEV, or other—varies by modelled scenario).

The following pieces of legislation and related decarbonization strategies below were modelled.

Advanced Clean Fleets (ACF)

On April 28, 2023, California passed the Advanced Clean Fleets regulation to help achieve Governor Gavin Newsom's goal of transitioning trucks in California to using zero-emissions technology by 2045.[35, 36] The ACF regulation states:[37]

High priority and federal fleets must comply with the Model Year Schedule or may elect to use the optional ZEV Milestones Option to phase-in ZEVs into their fleets:

- *Model Year Schedule: Fleets must purchase only ZEVs beginning 2024 and, starting January 1, 2025, must remove internal combustion engine vehicles at the end of their useful life as specified in the regulation.*
- *ZEV Milestones Option (Optional): Instead of the Model Year Schedule, fleets may elect to meet ZEV targets as a percentage of the total fleet starting with vehicle types that are most suitable for electrification.*

Since the ZEV Milestones Option is listed as optional and would often require fleet operators to retire vehicles earlier than they normally would, Option 1 was modelled. This takes the more conservative view that vehicles would generally be replaced with ZEVs when they would organically retire. Specifically, the AL Phase One Demand Study model reflects:

- 100% of truck sales starting 2024 will be ZEV for ACF priority fleets.
- 100% of truck sales starting 2035 will be ZEV for all fleets.

Exponential adoption rates were modelled to ramp up to the 100% by 2035 requirement.

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[35] https://ww2.arb.ca.gov/resources/fact-sheets/carb-fact-sheet-2023-advanced-clean-fleets-regulation-drayage-truck#:~:text=On%20April%2028%2C%202023%2C%20CARB,California's%20intermodal%20seaports%20and%20railyards
[36] https://www.gov.ca.gov/wp-content/uploads/2020/09/9.23.20-EO-N-79-20-Climate.pdf
[37] https://ww2.arb.ca.gov/our-work/programs/advanced-clean-fleets

Since the ACF regulation applies differently to those subject to it (priority fleets) versus those not subject to ACF, the vehicle populations listed previously were split using assessment of the type of vehicle as well as CARB's estimates for how many vehicles may be subject to the regulation:

- 100% of drayage trucks
- 67% of Class 7-8 Tractors
- 52% of Class 4-8 Vocational
- 12% of Class 2b-3

Finally, ACF states that ICE vehicles should retire after 18 years or 800,000 miles. However, most vehicles will retire organically before they would be flagged to retire according to ACF (see vehicle lifespan estimates above).

Advanced Clean Trucks (ACT)

The Advanced Clean Trucks regulation requires OEMs of medium- and heavy-duty vehicles to sell ZEVs at increasing rates through 2035 and beyond. In short, by 2035, OEMs must sell ZEVs as a portion of total sales:

- 55% of Class 2b-3 truck sales be ZEV by 2045
- 75% of class 4-8 straight truck sales be ZEV by 2045
- 40% of truck tractor sales be ZEV by 2045

Since the ACF regulation effectively requires 100% of truck sales to be ZEV by 2035, ACT's impacts are inherently considered in the AL Phase 1 Demand Study model through ACF's modelling.

Clean Air Action Plan (CAAP)

The Clean Air Action Plan is not a piece of legislation, but a strategy and proposal developed by the Port of Los Angeles and Port of Long Beach (together, the San Pedro Bay Ports). CAAP effectively states that terminal operators are expected to achieve 100% ZEV by 2030. While this is not strictly enforceable (it is not legislation), terminal operators have signed on and agreed to this, and so the AL Phase 1 Demand Study model considers these targets for all types of Cargo Handling Equipment (CHE) at the ports.

SoCalGas

Innovative Clean Transit (ICT)

The ICT legislation requires transit agencies to achieve net zero by 2035. Though many transit agencies have already committed to and have begun purchasing 100% ZEVs, transit agencies are required to submit their plans to achieve 100% ZEV to CARB. These plans are regularly revised.[38]

Executive Order N-79-20

For vehicle types not already covered by current legislation, such as for agricultural or construction equipment, there is no specific legislation yet. For these sub-sectors, guidance from EO N-79-20 was considered.[39] This executive order passed in 2020 set some of the initial State targets "to achieve 100 percent zero-emission from off-road vehicles and equipment operations in the State by 2035."

As done for other sub-sectors, where current ZEV populations are 0 (or effectively 0) today, exponential rates were assumed for the new sale of vehicles to achieve 100% of vehicle sales being ZEV by 2035.

Maritime Vessels and Aircraft

The largest maritime legislation passed is the Clean Shipping Act of 2023, which requires 100% clean shipping fuels by 2040 for most vessels.[40] Having passed in mid-2023, it is still unclear how shipping operators plan to achieve this, but more regulation is coming in this space. In addition to the Clean Shipping Act of 2023, some more niche legislation has passed, such as the 2021 ZEAT Commercial Harbor Craft Regulation[41] requiring CHC to have cleaner engines and for short-run ferries and excursion vessels to be 100% ZEV sales starting 2025.

Beyond these pieces of legislation, the 2022 CARB Scoping Plan[42] cites in their scenario that "25% of OGVs [will] utilize hydrogen fuel cell electric technology by 2045." It also states that "20% of aviation fuel demand is met by electricity (batteries) or hydrogen (fuel cells) in 2045."

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[38] https://ww2.arb.ca.gov/our-work/programs/innovative-clean-transit/ict-rollout-plans
[39] https://www.gov.ca.gov/wp-content/uploads/2020/09/9.23.20-EO-N-79-20-Climate.pdf
[40] https://www.congress.gov/bill/118th-congress/house-bill/4024/text?s=1&r=4
[41] https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2021/chc2021/chcfro.pdf
[42] https://ww2.arb.ca.gov/sites/default/files/2023-04/2022-sp.pdf

Given some of the uncertainties and continually developing legislation for marine vessels, legislation was accounted for in the following way:

- **Commercial Harbor Craft (CHC)**: the model assumes that new vessel engine sales will be 100% ZEV by 2035. This means that 100% of vessel engine sales will convert to hydrogen fuel cell, battery, or synthetic fuel technologies.
- **Ocean Going Vessels (OGVs)**: the model makes the conservative assumption that by 2045, 25% of OGVs will utilize non-synthetic fuel ZE solutions by 2045. The Hydrogen adoption rates reflect what percent of this 25% would utilize hydrogen fuel cell technology. As well, it's worth noting and reiterating that the model only accounts for replacing current diesel consumption by OGVs. Bunker fuel replacement (e.g., the main engine's typical fuel) is not considered.
- **Aircraft:** the model takes the 2022 CARB Scoping Plan assumption's estimate that 20% of aviation fuel demand would be non-SAF.

Hydrogen Adoption Rates

The scope of the AL Phase 1 Demand Study considered hydrogen fuel cell technology as a driver for hydrogen demand (i.e., hydrogen combustion was not considered for mobility applications). As such, hydrogen fuel cell technology was assessed and compared to various alternatives by application.

- On-Road (FCEVs) – the primary alternative considered was BEVs.
- Off-Road (FCEVs) – the primary alternative considered was BEVs.
- Marine (CHC) – the primary alternatives considered were both battery or hydrogen derivatives / synthetic fuels.
- Marine (OGV) – the primary alternative considered was hydrogen derivatives / synthetic fuels.
- Aircraft – the primary alternative considered was battery or sustainable aviation fuel[43]

Adoption Factors

To model how hydrogen fuel cell technology may stack up against these alternatives, and to determine the associated hydrogen adoption rates over time (as a % of ZEV), 4 primary factors were considered.

[43] The model assumes that the majority (80%) of aviation fuel will convert so SAF, but that the remaining 20% should be a comparison between fuel cell and battery aircraft.

1. Technical Feasibility—a metric to assess the likelihood of adoption for hydrogen fuel cell technology against alternatives based on technical or operational factors such as range requirements, load requirements, duty cycle, etc. The factors vary across on-road, off-road, and other sub-sector applications.
2. Commercial Availability—a metric reflecting if and when FCEV technology is commercially available. This factor is quantified using TCO cost values—less fuel costs—based on Argonne National Lab's (ANL's) BEAN model.
3. Business Readiness—a metric that accelerates or decelerates adoption rates based on business factors. For example, an industry with companies setting near-term zero emissions targets may choose to accelerate adoption of ZEVs.
4. Policy & Regulation—a metric that accelerates or decelerates adoption rates based on potential changes in existing legislation. For example, as of the time of writing, the DOE's recently announced Demand-side Support Mechanism could be an accelerator for hydrogen FCEV adoption.[44]

Each of these factors constituted unique evaluation by vehicle application grouping. To model associated H2 adoption rates (as a % of ZEV adoption rates), variables for the 4 factors were multiplied:

$$R(T, C, B, P) = T * C_{t,s} * B_{t,s} * P_{t,s}$$

R = *H2 Adoption Rate [0, 1]*

T = *Technology Feasibility [0, 1]*

C_t = *Commercial Availability [0.05, 1.5]*

B_t = *Business Readiness [0.8, 1.2]*

P_t = *Policy & Regulation [0.8, 1.2]*

t = *time value for evaluation: 2025, 2030, 2035, 2040, 2045 (e.g., each factor listed is evaluated at each time period indicated)*

s = *scenario (low, medium, high)*

The resultant hydrogen adoption rates, represented as values between 0% and 100%, were a proportion of zero emission technology. For example, if the hydrogen adoption

[44] https://oced-exchange.energy.gov/Default.aspx#FoaId8e15135b-a033-47ca-9c7a-ebf2e5771a41

fuel cell rate of 20% is calculated for a certain on-road vehicle type, then this would mean that 80% adoption is covered by battery electric vehicles.

The hydrogen adoption rate factors were generally evaluated as follows:

Table 6: High-Level definition of H2 Adoption Rate Factors (Mobility)

<table>
<tr><th>Factor</th><th>Conservative</th><th>Moderate</th><th>Ambitious</th></tr>
<tr><td>Policy & Legislation</td><td colspan="2">Only existing legislation considered</td><td>Existing legislation +additional potential legislation 2025 onwards (↑10% H2 adoption)</td></tr>
<tr><td rowspan="2">Commercial Readiness</td><td>Conservative timeline to achieve cost parity with decarbonization alternatives</td><td>Moderate timeline to achieve cost parity with decarbonization alternatives</td><td>Ambitious timeline to achieve cost parity with decarbonization alternatives</td></tr>
<tr><td colspan="3">Assessed by modelling TCO (without fuel cost) for on-road using ANL’s BEAN model, and market research for non-on-road applications.[45]</td></tr>
<tr><td>Technical Feasibility</td><td colspan="3">Evaluated per vehicle application group but held constant across scenarios.</td></tr>
<tr><td>Business Readiness</td><td>Conservative assessment of market readiness to adopt hydrogen vehicles</td><td>Moderate assessment of market readiness to adopt hydrogen vehicles (↑10% H2 adoption 2035-)</td><td>Ambitious assessment of market readiness to adopt hydrogen vehicles (↑20% H2 adoption in 2030; ↑10% in 2035-)</td></tr>
</table>

Technical Feasibility

Technology feasibility is evaluated on a series of factors f. The list of factors varies by sub-sector (on-road, off-road, marine, aviation).

[45] https://vms.taps.anl.gov/tools/

$$T_f = \frac{\sum_1^n f_n}{n}$$

Each factor is evaluated as Very Low (0%), Low (25%), Medium (50%), High (75%), or Very High (100%) to indicate likelihood of H2 adoption based on that factor alone. Values for each factor are averaged to determine the net likelihood of H2 adoption, T_f, based on Technical and Operational characteristics alone (n = number of factors).

The metrics evaluated were unique to each sub-sector group:

- On-Road applications were evaluated on the metrics of range requirement, load requirement, duty cycle requirement, and fueling requirements.
- Cargo Handling Equipment applications were evaluated on the metrics of load requirements, duty cycle requirements, proven viability of EV technologies, sufficient space & time for charging/fueling, and infrastructure challenges for electrification.
- Ground Support Equipment applications were evaluated on the metrics of load requirements, duty cycle requirements, centralization of fueling operations, and infrastructure challenges for electrification.
- Other off-road equipment applications were evaluated on the metrics of load requirements, infrastructure challenges for electrification, and duty cycle requirements.
- Commercial Harbor Craft applications were evaluated on the metrics of weight and size impact of H2 vs alternatives (if structural changes would be needed on ships), and operational shift requirements (how long vessels tend to be working and away from port).
- Ocean Going Vessel applications were evaluated on the metrics of weight and size impact of H2 vs alternatives (if structural changes would be needed on ships), and operational shift requirements (how long vessels tend to be working and away from port).
- Aircraft were evaluated on the metrics of weight and size impact of H2 vs alternatives (if airplane design changes would be needed), and operational shift requirements (how long aircraft would need to fly before refueling/recharging).

For Example, T_f for Class 8 Sleeper Cab Tractors is evaluated as:

$$f_1 = Range\ Requirement = Very\ High = 100\%$$

$$f_2 = Load\ Requriement = High = 75\%$$

$$f_3 = Duty\ Cycle\ Requirement = High = 75\%$$

$$f_4 = Fueling\ Requirements = High = 75\%$$

$$T_{f,\ Class\ 8\ Sleeper\ Cab\ Tractor} = \frac{\sum_1^n f_n}{n} = 81\%$$

The evaluation of on-road vehicles considered some of the following research and analysis:

- **Range requirements** – Current diesel semis reportedly have a maximum range of approximately 2,000 miles, which is well beyond the capabilities of all BEV and FCEV options except for FCEV trucks with liquid hydrogen fuel storage. This statistic will be a challenge for FCEVs and BEVs to address, however federal hours of service rules allow a driver to drive for a maximum of 8 hours before stopping for a break, which would equate to 600 miles of driving at a relatively fast 75 MPH.[46] The range of diesel semis would allow drivers to avoid multiple fuel stops, but if sufficient infrastructure was available a much lower range could be acceptable.
- **Load requirements** – The expected mass impact for current battery technology was evaluated: Battery cells currently have a specific energy of approximately 250 Wh/kg. BEV trucks with this technology will have a cargo/mass tradeoff above approximately 450 miles of range relative to diesel trucks, while compressed hydrogen would have much lower sensitivity and liquid hydrogen would be superior to diesel for all vehicle ranges. However, if battery energy density improves to 400 Wh/kg, this tradeoff does not occur until approximately 750 miles of range relative to diesel. No current commercial battery achieves an energy density this high, but various battery companies have announced that they have achieved battery densities this high or higher in prototype cells.[47, 48, 49, 50] Although it will take considerable development efforts to bring these

[46] https://www.federalregister.gov/documents/2020/06/01/2020-11469/hours-of-service-of-drivers
[47] https://cleantechnica.com/2020/08/25/tesla-air-elon-musk-hints-tesla-could-mass-produce-400-wh-kg-batteries-in-3-4-years/
[48] https://cleantechnica.com/2022/07/24/svolt-energy-readies-solid-state-battery-with-400-wh-kg-energy-density-for-production/
[49] https://www.electrive.com/2023/03/30/amprius-achieves-battery-energy-density-of-500-wh-kg/
[50] https://www.batterytechonline.com/battery-news/catl-s-aerospace-ready-battery-has-energy-density-to-500-wh-kg

technologies to production, if these efforts were successful, they could make BEV semis as competitive as compressed hydrogen FCVs.

- **Duty cycle requirements** – Another challenge for zero emissions trucks is refueling time. This is most important for trucks that operate with high duty cycles (2 or 3 eight-hour shifts per day). Although standards for recharging and refueling heavy duty BEV and FCEV semis have not been developed yet, it is likely that fueling times for both compressed and liquid hydrogen FCEVs can be made comparable to diesel, given that this has been achieved for light-duty applications. This will be effectively impossible for BEV semis since this would require very high-power levels.
- **Fueling requirements** – There are 2 factors of fueling requirements considered to assess the viability of BEV vs FCEVs: centralization of fueling operations, and difficulty in building fueling/charging infrastructure. Some considerations are as follows:
    - Building ubiquitous retail fueling stations akin to gas or diesel stations today will be a challenge for both technologies (to maintain customer expectations). This issue would be less prevalent with MDV and HDF fleets which operate more often with back-to-base operations. The notable exception here is long-haul tractors which refuel in highly distributed locations. For long-haul, high-power charging would be needed (up to 4.5 MW per charger for long-haul), which would require significant upgrades to electrical capacity; the steep load peaks would be difficult to manage too.
    - Hydrogen is primarily delivered to fueling stations today as a compressed gas (via tube trailers) for the LDV. Liquid hydrogen delivery being pursued for higher-volume/heavier-duty fueling stations (even for gaseous fueling) due to energy density advantages.[51]
    - Electricity must be used in real time, coordinating the direct use of electricity with a desired generation source may be difficult. Energy storage solutions (like batteries) at charging stations can help to address this mismatch but would be expensive. Hydrogen meanwhile would not have this real-time electricity production/offtake mismatch issue.
    - Compressed hydrogen fueling stations require significantly more space than conventional (diesel) stations for compressors and other equipment, and significant electric power capacity is required to run compressors.[52]

[51] https://www.nrel.gov/docs/fy22osti/83036.pdf
[52] https://nacfe.org/wp-content/uploads/2023/04/H2-NACFE-2023-Report-FINAL.pdf

Evaluation for off-road vehicles, marine vessels, and aircraft was based on comparable logic and methodology. Where less information was available, high-level estimates were made based on industry reports and interviews.

Commercial Availability

On-Road

Data and Assumptions

Commercial availability, $C_{t,s}$, is evaluated by application, by scenario s over time, t. Values for $C_{t,s}$ were developed by leveraging TCO analysis done by Argonne National Labs' (ANL) BEAN model.[53] The defaulted values from BEAN were leveraged except for 3 exceptions:

Exception 1: Fuel Cell Costs

Fuel Cell costs were increased vs the default values in the ANL BEAN model as they were intentionally set by ANL to reflect price parity of diesel engines. For comparison, the DOE's target values are also shown.

Table 7: Fuel cell costs used in TCO analysis vs ANL defaults and DOE target.

Transit, Box Medium 6 ($/kw)	2025	2030	2050
ANL (High)	126	70	50
ANL (Mid)	126	90	65
ANL (Low)	126	110	80
DOE (MDV)	177	157	
Values Used (High)	231	128	92
Values Used (Low)	651	361	257

HDV/Day Cab Sleeper ($/kw)	2025	2030	2050
ANL (High)	130	80	60
ANL (Mid)	136	97	73
ANL (Low)	142	113	85
DOE (HDV)	145	107	60

[53] ANL BEAN Model: https://vms.taps.anl.gov/tools/

Values Used (High)	238	146	110
Values Used (Low)	671	412	309

Exception 2: H2 Storage Costs

Hydrogen storage tanks on vehicles are improving but continue to carry significant cost vs diesel or gasoline alternatives. Cost estimates for these storage tanks were updated and modelled reflecting the below assumptions:

Table 8: Hydrogen storage costs used in TCO analysis vs ANL defaults (Variable)

Hydrogen storage variable costs $/kg	2025	2030	2050
ANL (High)	274	247	219
ANL (Mid)	289	260	233
ANL (Low)	301	274	247
Values Used (all scenarios)	495	424	377

Table 9: Hydrogen storage costs used in TCO analysis vs ANL defaults (Fixed)

Hydrogen storage fixed costs $/kg	2025	2030	2050
ANL (High)	3,366	3,029	2,693
ANL (Mid)	3,534	3,198	2,861
ANL (Low)	3,703	3,366	3,029
Values Used (all scenarios)	5,790	5,211	4,632

Exception 2: Battery Costs

Batteries are one of the main cost components in battery electric vehicles (BEVs), the primary foreseeable ZEV alternative for FCEV technology. Battery costs were updated as follows:

Table 10: Battery costs used in TCO analysis vs ANL defaults.

Battery costs ($/kWh)	2025	2030	2050
ANL (High)	95	75	60
ANL (Mid)	112	88	65
ANL (Low)	128	100	70
Values Used (all scenarios)	79	63	50

TCO Curve Development and Analysis

With the above changes, the BEAN model was leveraged to generate TCO cost curves for each on-road vehicle class. These cost curves were leveraged to determine how commercially viable certain technologies would be against alternatives.

First, the BEAN model was used to gather data across the following metrics:

- Years: 2025, 2030, 2035, and 2050
- Vehicle cost characteristics: Vehicle, Financing, Fuel, Insurance, Operation, Tax & Fees, M&R (repairs).
- Applications: LonghaulSleeper 8, RegionalDayCab 8, DrayageDayCab 8, TransitHeavy 8, BoxMedium 6, Small SUV
- Fuel Type: ICE, BEV, FCEV

Fuel costs were omitted from the model, but all other values were utilized to determine lifetime total costs of ownership (TCO). For where there are gaps in data, linear approximations were made: costs between data in years provided were calculated linearly; costs for vehicle classes were calculated linearly (e.g., Class 7 costs were an average of Class 8 and Class 6 costs). ANL's BEAN model only provides data for on-road applications.

Second, once annual costs were derived by vehicle application group, for ICE, BEVs, and FCEVs, the following definitions were adopted to determine values of $C_{t,s}$:

- Far From Parity = when TCO_{FCEV} >20% more expensive than $TCO_{Alternatives}$
- Close to Parity = when TCO_{FCEV} is between 10% and 20% more expensive than $TCO_{Alternatives}$
- At Parity = when TCO_{FCEV} is within 10% of $TCO_{Alternatives}$

- Cheaper = when TCO_{FCEV} is between 10% and 20% cheaper than $TCO_{Alternatives}$
- Much Cheaper = when TCO_{FCEV} is >20% cheaper than $TCO_{Alternatives}$

Note: FCEV alternatives for TCO comparison consist of ICE and BEVs through 2035 (FCEV is compared against whichever alternative is the lowest cost that year), but only BEVs after 2035 (due to ACF and associated legislation).

Since the cost curves are shown over time, values for $C_{t,s}$ are determined at each time period t (2025, 2030, 2035, 2040, 2045) across each scenario s (Low, Mid, High), by application. One example, for the Class 8 Sleeper Cab Tractor application is listed below:

Table 11: Example TCO Outputs for Modelling (Class 8 Sleeper Cab Tractor)

Class 8 Sleeper Cab Tractor TCO Evaluation	2025	2030	2035	2040	2045
Low Scenario	Far from Parity	Far from Parity	Close to Parity	Close to Parity	At Parity
High Scenario	Close to Parity	At Parity	At Parity	At Parity	At Parity

Note: values for the Moderate scenario were taken as the mid-point between the Conservative and Ambitious scenarios.

Third, the adoption rate factors were applied at each time interval to determine the multiplier effect of the Commercial Availability $C_{t,s}$ variable:

Table 12: Definition of Commercial Availability Values (TCO Parity Value Assumptions)

Evaluation	Value
Far from Parity	5%
Close to Parity	50%
At parity	100%
Cheaper	125%
Much Cheaper	150%

Note: no outputs from the ANL BEAN model showed FCEVs ever achieving >10% cost advantage over alternatives, so the “Cheaper” and “Much Cheaper” scenarios were never achieved.

Off-Road (including Marine and Aviation)

For non-on-road applications, fewer models exist, but there is a decent amount of 3rd party research which was leveraged to determine the denotation of far from parity, close to parity, or at parity for these applications. Where no data was available, best estimates were made, or cost assumptions were based on comparable on-road values where possible, generally with a 5+ year lag in evaluations. This assumption was made as a reflection of the number of OEMs announcing production of off-road fuel cell vehicles being generally behind that of on-road vehicles (similar to how legislation for off-road applications is lagging that of on-road applications). Also, many off-road applications may be more viable options for engine swaps, where the combustion engine in a vehicle may be swapped out with a fuel cell, but the rest of the vehicle remains unchanged. This could be a particularly attractive option for some applications where most of a vehicle's costs are not the engine (such as a large crane).

Select references for off-road TCO evaluations include those from the EPA,[54] DOE,[55] and ANL.[56]

Business Readiness

Business Readiness is a multiplying factor used to reflect the impact of companies or firms accelerating (or decelerating) their adoption of FCEV technology. For example, many global organizations have set Net Zero targets and will likely be early adopters of FCEV or BEV technology. If they adopt primarily FCEV technology, this will accelerate H2 adoption.

Table 13: Definition of Business Readiness Values

Evaluation	Value
Laggard	80%
Delayed	90%
Market Driven	100%
Fast Follower	110%
Early Adopter	120%

54 https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P1015AQX.pdf
55 https://www.hydrogen.energy.gov/pdfs/review23/ta065_ahluwalia_2023_o.pdf
56 https://www.energy.gov/sites/default/files/2021-12/922-9-mission-innovation-ANL.pdf

There are many companies with Net Zero Targets, and many have signed up and publicized these policies, such as with Net Zero Tracker.[57] Since assumptions were conducted at the vehicle application level, evaluations were not an explicit representation of individual company commitments, but rather a representation of how fleet operators may act.

In the Low scenario, all evaluations across all time periods across all applications were evaluated as Market Driven, meaning the multiplier would be 100% and that H2 adoption rates would not be impacted by business readiness. For Medium and High scenarios standard evaluation were used across most applications reflected in Table 14, below.

Table 14: Standard Evaluations of Business Readiness Across Scenarios

Scenario	2025	2030	2035	2040	2045
Low Scenario	Market Driven	Market Driven	Market Driven	Market Driven	Market Driven
Medium	Market Driven	Fast Follower	Fast Follower	Fast Follower	Fast Follower
High Scenario	Market Driven	Early Adopter	Fast Follower	Fast Follower	Fast Follower

Policy & Regulation

While policy and regulation considerations are already factored into the model through the ZEV adoption rates and existing legislation (see Mobility - Assumptions section), an additional factor was added to consider potential changes in legislation. Similar to Business Readiness, the Policy & Regulation driver was defined as follows:

57 https://zerotracker.net/

Table 15: Definition of Policy & Regulation Driver Values

Evaluation	Value
Significantly Delayed Legislation	80%
Delayed Legislation	90%
Existing Legislation	100%
Some H2 Legislation	110%
Significant H2 Legislation	120%

It's important to reiterate that this additional factor differs from existing legislation, in that existing legislation has already been taken into account in the model to inform the % of ZEV sales, and this additional factor affects the % of FCEV sales out of the ZEV sales.

In the Conservative and Moderate scenarios, this model driver effectively has no impact on H2 adoption rates as only existing legislation is reflected (the multiplier value is 100%). For the Ambitious scenario, the possible impact of potential additional legislation is reflected across the entire modelled time period.

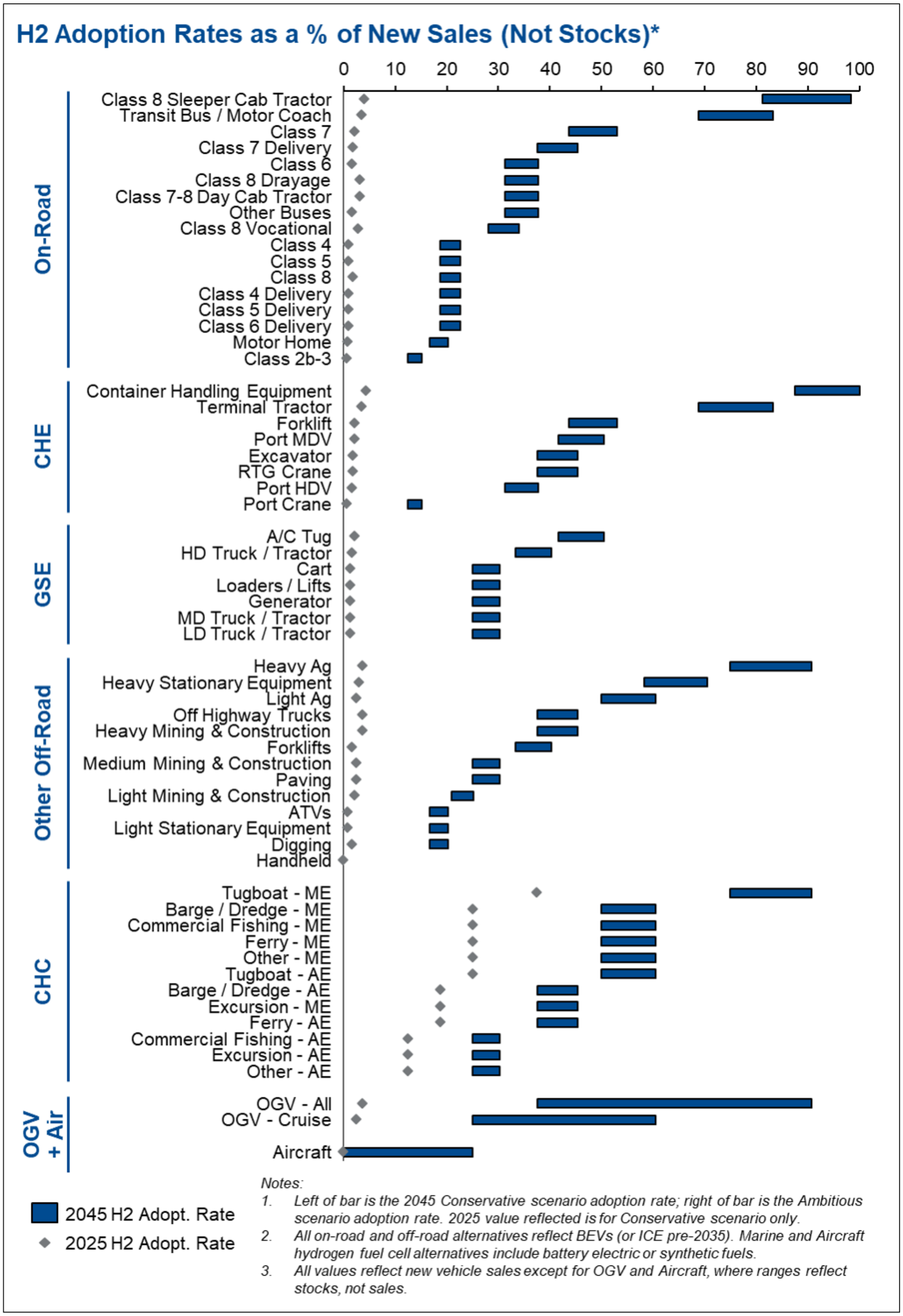
Table 16: Standard Evaluations of Policy & Regulation Variable Across Scenarios

Scenario	2025	2030	2035	2040	2045
Low Scenario	Existing Leg.	Existing Leg.	Existing Leg.	Existing Leg.	Existing Leg.
Medium	Existing Leg.	Existing Leg.	Existing Leg.	Existing Leg.	Existing Leg.
High Scenario	Some H2 Leg.	Some H2 Leg.	Some H2 Leg.	Some H2 Leg.	Some H2 Leg.

Hydrogen Adoption Rates Utilized

From the above assessments, hydrogen adoption rates (vs alternatives) of new vehicle sales were developed by application group from 2025-2045, by scenario. All vehicles in the same application group (as defined above) were assumed to have the same adoption rates.

Figure 3: Hydrogen Adoption Rates of New Vehicle Sales Utilized (2045 Values)



Power

Methodology

To assess hydrogen demand in the Power sector, a yearly hydrogen adoption rate from 2025-2045 was calculated based on detailed input data, and this adoption rate was multiplied by current natural gas consumption to determine aggregate hydrogen demand in the SoCalGas territory.

Facility-Level Fuel Consumption

Current Plant Data is used from EIA 923[58] and EIA 860[59]. Data used includes operator, nameplate capacity, historical generation and fuel consumption on an MMBTU basis, turbine type, summer and winter nameplate capacity, and heat rates. EIA provides data across the following turbine types:

Figure 4: Different Turbine Types for Fuel Consumption Analysis

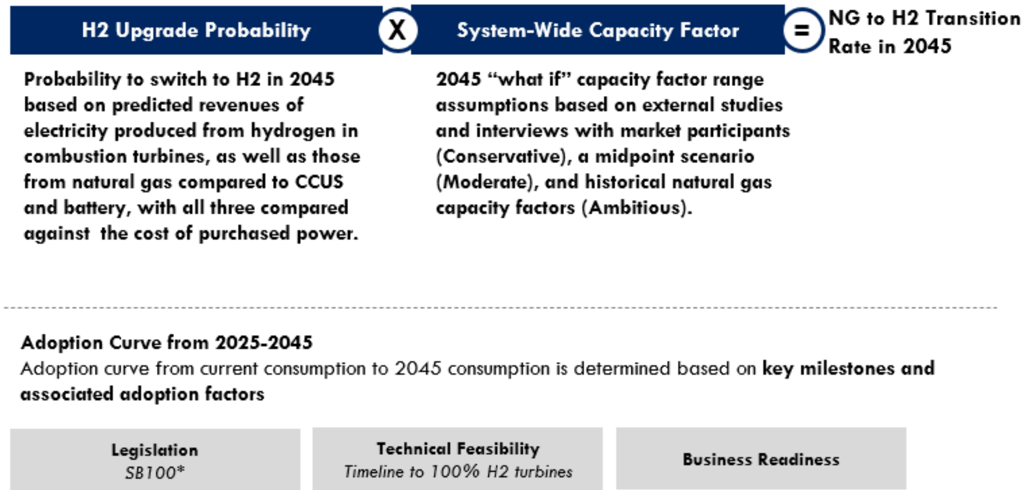
Combined cycle combustion turbine	Combustion turbine
Steam turbine	Combine cycle steam turbine part
Combined cycle single shaft	Internal combustion turbine

From the dataset, current natural gas combustion of power plants measured on an MMBTU basis is used as basis for future hydrogen consumption. Detailed data at the plant level was also gathered through individual external research and included current capacity, turbine OEM and model, and current blending capability. Fuel usage data was found for all plants. Turbine OEM, model, and blending data were only found for a subset of plants.

[58] Form EIA-923 detailed data with previous form data (EIA-906/920) - U.S. Energy Information Administration (EIA) https://www.eia.gov/electricity/data/eia923/
[59] Form EIA-860 detailed data with previous form data (EIA-860A/860B) https://www.eia.gov/electricity/data/eia860/

Hydrogen Adoption Rate

Figure 5: Hydrogen Adoption Rate Methodology Diagram



* Although SB100 framework does allow for an emission budget, the analysis conservatively assumed zero emission by 2045 under SB100

Two key inputs were used to determine the hydrogen adoption rate:

1. Hydrogen upgrade probability: Determines power capacity that will be transitioned to hydrogen by 2045.
2. Capacity Factor: Determines the utilization of capacity once traditional capacity has transitioned.

These two factors were used to quantify the total generation from hydrogen in 2045. Yearly adoption rates were developed on a ramp from 2025-2045, with key milestones guiding the shape of this curve based on legislation, commercial availability, technical feasibility, and business readiness.

Assumptions

Addressable Market

- Only power facilities with a capacity of >1MW have been considered as potential end users in this phase.

- Power facilities were filtered from EIA form 923 2021 dataset[60], which provides data for all power generation facilities in the nation. This dataset was filtered to include only natural gas combustion data (EIA Code: NG). A filter was also applied on the sector name to ensure only facilities within the power sector were included in the model. Sectors included are:
    - Electric utilities
    - NAICS-22 non-cogen
- All facilities in SoCalGas territory and territories where SoCalGas provides wholesale natural gas are considered potential adoptees of hydrogen for this study, except for facilities in SDG&E territory / San Diego, which have been excluded.

Hydrogen Adoption Factor Assumptions

<u>Policy & Legislation</u>

Senate Bill 100 (2018)[61]

- Requires renewable energy and zero-carbon resources to supply 100% of electric retail sales by 2045. Model assumes 100% emission reduction by 2045, although SB100 framework allows an emission budget.

- Provides interim milestone of 60% of electric retail sales to be met by eligible renewable resources by 2030.

- 100% carbon free assumption based on legislative 2045 timelines.

Senate Bill 1020 (2022)[62]

- Requires eligible renewable energy resources and zero-carbon resources supply 90% of all retail sales of electricity by 2035, 95% by 2040, and 100% by 2045. This bill was not factored into the power sector modeling for this first phase but was acknowledged in the report as legislation that could help drive adoption of

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[60] Form EIA-923 detailed data with previous form data (EIA-906/920) - U.S. Energy Information Administration (EIA) https://www.eia.gov/electricity/data/eia923/
[61] SB 100 Joint Agency Report (ca.gov) https://www.energy.ca.gov/sb100
[62] Bill Text - SB-1020 Clean Energy, Jobs, and Affordability Act of 2022. (ca.gov) https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=202120220SB1020

clean renewable hydrogen adoption. This will be factored in for future demand assessments.

Technical Availability

- Current blending percentage is taken at the plant level, with current turbines in SoCalGas territory capable of 5-75% blending with a majority of gas turbines at 20-30%. However, plant modifications would be required.
- Projected 2030 as a milestone for 100% H2 turbine technical capability.

Commercial Availability

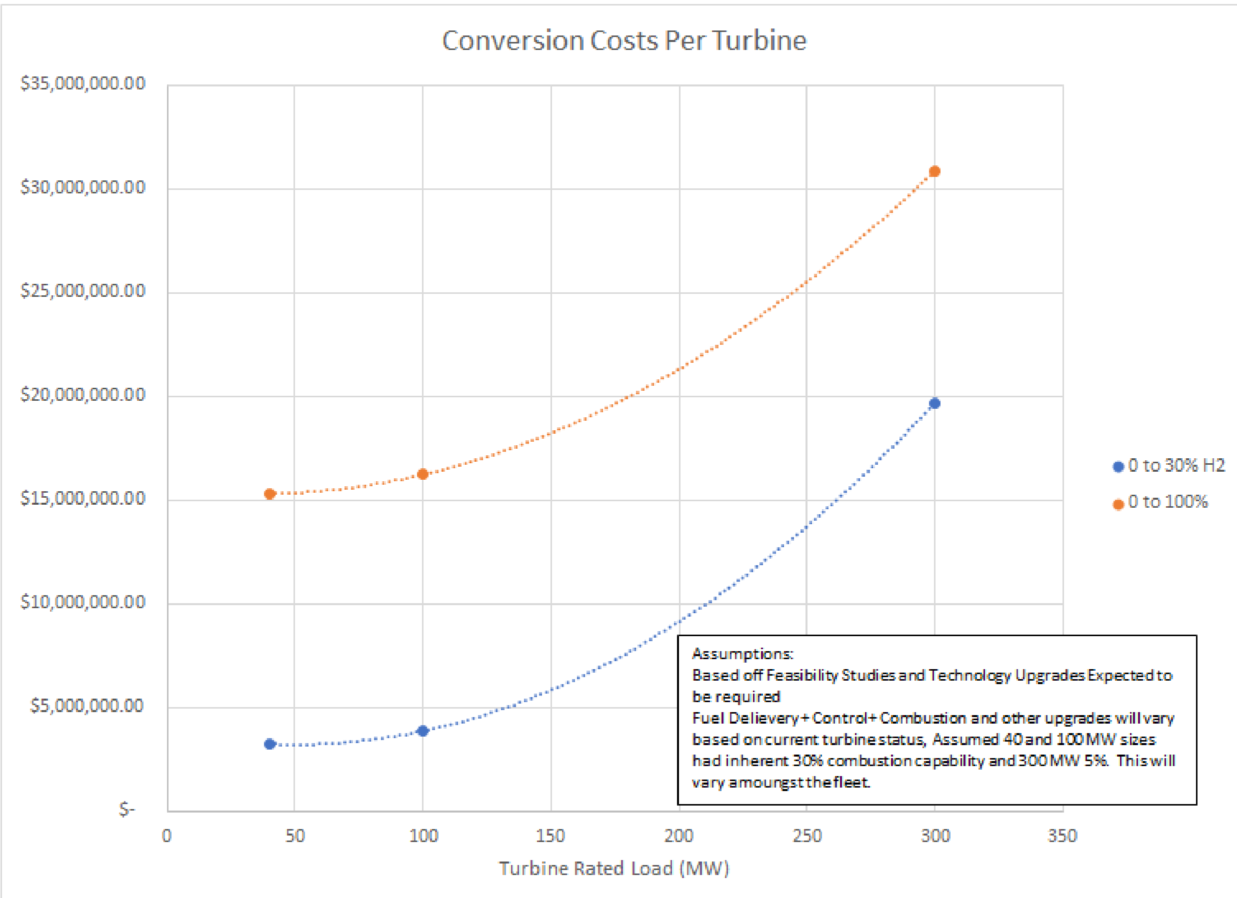
Hydrogen is assessed at price parity with the existing price of incumbent fuels without a carbon price, as shown in the Additional Quantitative Assumptions section. Hydrogen upgrade costs are developed at a plant level across various upgrade ranges. The graph below shows the projected costs for a variety of hydrogen upgrades across different turbine sizes and upgrade percentages, developed based on a green hydrogen FEED study by EPRI[63]. In this FEED study a 30% blend capability for a small GT was estimated at $3,000,000 for the GT upgrades based on 3 scenarios that were evaluated, a short demonstration, and permanent installations with varying blends. As combustion system upgrades are added to the costs it is expected they will significantly increase the overall cost of the upgrade. There are major cost variations which were not evaluated here such as differences among OEMs, the current condition of the power plant units, the potential need for different upgrades between different sites (as some sites may need fuel delivery), combustion variations, control systems and other upgrades including "soft" costs like upgrading their site procedures. Combustion system upgrades that are required for higher hydrogen blends were expected to contribute to a larger cost increase. There was little data on exact combustion upgrade costs to rely on for the study. However, FEED study data[64] shows that the cost to upgrade an existing combustion system (already developed) was calculated to be 5% of the total gas turbine cost, which is roughly $0.7 to $2MM/MW[65]. This suggests roughly $4 to $20 million for a combustion retrofit upgrade depending on the system size to

[63] Feasibility Study for Green Hydrogen Generation and Cofiring Hydrogen in an Aeroderivative Gas Turbine: Solar, Battery Energy Storage System, Desalination, Electrolyzer, Hydrogen Storage, Natural Gas Blending, and LM2500 Gas Turbine Operation (epri.com) https://www.epri.com/research/products/000000003002025998
[64] Ibid
[65] It is assumed that up to 30% will only require accessory upgrades, and 30 to 100% upgrades require a combustion system upgrade. These numbers do not include construction, labor, contingency, etc. and only represent part of the cost estimate.

achieve 30% hydrogen blends. These numbers may be subject to inflation and other variables.

The cost to upgrade was chosen as the lowest cost between a full upgrade from 0 to 100% hydrogen capability and retrofit costs from the current capability to 100% based on turbine size. Current hydrogen capability was determined based on plant-level research as described in the Blending section below.

Figure 6: Turbine Conversion Costs



Hydrogen is compared to alternatives on a cost and profit basis to determine hydrogen upgrade probability using the following inputs:

- Battery Install cost: $2M/MWh, CCUS Capital Cost: $1,727/KW, CCUS T&D cost: $3.7/MWh[66]
- Peak Demand Power Cost: $0.50/KW, Revenue Power Charge: $0.12/KW

Business Readiness

- Projected that business readiness will take 5-8 years due to business decision making, permitting, construction for new turbines, and retirement rates of current turbines. This means 2030 is the earliest that hydrogen turbines will move to 100% H2. In the model, transition starts slowly in 2030 and progressively increases as we near 2045. These assumptions were based on interviews with plant operators.

Additional Quantitative Assumptions

Table 17: Power Quantitative Assumptions

Assumption	Value	Explanation
H2 Cost $/Kg	$0.289	This cost was converted to $/mmbtu to have the assumption of price parity with $/mmbtu of natural gas. This is the most justifiable from a "price parity" assumption as the gas turbine's do not require a set mass (kg) of fuel but rather an energy input (mmbtu). Also, if price parity was assumed on a $/kg basis, then hydrogen would actually be ~2.5 times cheaper on a $/mmbtu basis. See the conversion below under NG Cost $/kg.
Electricity Costs $/KWh for Battery Charge	0.2	It is assumed batteries are charged in the daytime when there is an excess of renewables. Therefore, this cost is less than the Revenue Power Charge
Peak Demand Power Cost $/KWh	0.5	When these assets are called upon, it is expected to be when there are not enough renewables to cover the generation required by the grid. Because of this, power prices will increase. For this reason, this price is higher than the Revenue Power Charge

[66] Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity (Technical Report) | OSTI.GOV https://www.osti.gov/biblio/1893822

Revenue Power Charge $/KWh	0.22	This is average cost of energy to end use customers based on EIA data. Electric Power Monthly - U.S. Energy Information Administration (EIA)
Time Horizon (Years)	10	The number of years used when calculating costs, revenues, and profit.
Battery Storage Installation Cost $/MWh	$2,000,00	The CapEx cost associated with installation of battery storage at a plant. This includes more than just the battery cost itself and is based on EPRI analysis
CCUS Capital Cost $/KW	$1,727	The 95% carbon capture case on an F Class machine was used for cost data[67]. For this, the $/kW of the “Flue Gas Cleanup” and “Feedwater & Miscellaneous BOP systems” were added together to get the upgrade cost. Source data for these costs were for a new plant, not retrofits, so other cost line items that were more specific to a new plant were not included because the Demand Study is only comparing against CCUS achieved through plant retrofits.
CCUS Transportation and Storage Cost $/MWh	$3.70	Taken from the same source as above, the cost to transport and store the captured carbon. This may be a conservative estimate and will vary based on location, size, and other variables.
NG Cost $/kg	$0.113	Natural gas cost is widely available and often quoted in $/mmbtu. The model uses Henry Hub Natural Gas Spot Price (Dollars per Million Btu) | EIA.GOV as a source.[68] However, hydrogen is usually quoted in $/kg so for this exercise, the units were converted from $/mmbtu to $/kg. The conversion was done as below: $\frac{\$0.113}{kg_{NG}} * \frac{1kg_{NG}}{55.5MJ} * \frac{1MJ}{0.0009478MMbtu} = \frac{\$2.15}{MMbtu}$
NG MJ/kg	55.5	A property of methane.

[67] Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity (Technical Report) | OSTI.GOV https://www.osti.gov/biblio/1893822 , page 613
[68] Henry Hub Natural Gas Spot Price (Dollars per Million Btu) (eia.gov) https://www.eia.gov/dnav/ng/hist/rngwhhdM.htm

Peak Demand and Storage

To provide context to the demand of hydrogen and specifically the peak hydrogen demand requirements, additional storage and operational considerations may be needed to meet 100% load on peak days. This demand study looks at annual hydrogen demand quantities, but this demand will be highly variable throughout the year and will see sharp increases on peak days where turbines are running at 100% load. Depending on the infrastructure in place, hydrogen storage may be needed and will drive additional costs and land requirements not represented in the model.

Blending (Behind-the-Meter)

A switch from blending to 100% hydrogen turbines from 2025-2045 has been integrated into the model, with blending occurring at low levels to start based on current capabilities. Current capabilities have been determined at the plant level where turbine model data is available, based on EPRI modelling of current capabilities shown in the figure below. Blending capability is multiplied by electric fuel consumption (MMBTU) at the plant and aggregated across plants to determine total blending potential inputted to demand sector model. It should be noted that consistent with the Decision, Angeles Link is intended as a project to transport only 100% clean renewable hydrogen in the pipeline, and any analysis of hydrogen blending refers strictly to “behind-the-meter” operations, not within SoCalGas control.

Figure 7: Current Hydrogen Blending Capabilities of Various Turbines

OEM	Type	Notes	TIT C[F] or Class	H2 % (Vol)	Source
MHPS	Diffusion	N2 Dilution, Water/Stean	1200~1400 [2192~2	up to 100	EPRI
MHPS	Pre-Mix (DLN)	Dry	1600 [2912]	up to 30	EPRI
MHPS	Multi-Cluster	Dry	1650 [3002]	up to 30	EPRI
GE	SN	Single Nozzle (Standard)	B,E Class	up to 100	EPRI
GE	MNQC	Multi-Nozzle Quiet Combu	E,F Class	up to 100	EPRI
GE	DLN 1	Dry	B,E Class	up to 33	EPRI
GE	DLN 2.6+	Dry	F,H Class	up to 20	EPRI
GE	DLN 2.6e	Dry	H Class	up to 50	EPRI
Siemens	DLE	Dry	E Class	up to 30	EPRI
Siemens	DLE	Dry	F Class	up to 30	EPRI
Siemens	DLE	Dry	H Class	up to 30	EPRI
Siemens	ACE	Dry	HL Class	up to 50	EPRI
Ansaldo	Sequential	GT26	F Class	up to 30	EPRI
Ansaldo	Sequential	GT36	H Class	up to 50	EPRI
PSM	LEC-III TM	DLE	B, E Class	up to 50	EPRI
PSM	Current Flamesheet TM	DLE	Frame 5, 6B, 7E, 9E,	up to 60	EPRI
Baker Hughes	DLN	Frame 6/7/9	Frame 6/7/9	up to 32	EPRI
Baker Hughes	Diffusion	Frame 6/7/9	Frame 6/7/9	up to 100	EPRI
Siemens	DLE	SGT		up to 10-75	EPRI
Siemens	Diffusion	SGT-100,400		up to 65	EPRI
Baker Hughes	DLN	PGT10		up to 8	EPRI
Baker Hughes	DLN	NovaL		up to 30	EPRI
Baker Hughes	DLN	Frame 6/7/9		up to 32	EPRI
Baker Hughes	Diffusion			up to 100	EPRI
Solar	SoLoNOxTM			up to 20	EPRI
Solar	Diffusion			up to 100	EPRI
GE	DLE	TM/LM		up to 35	EPRI
GE	Diffusion	TM/LM		up to 75/85	EPRI
Siemens	DLE	SGT-A35/SGT-A05		up to 15/30	EPRI
Siemens	Diffusion	SGT-A35		up to 100	EPRI

Factors That Could Potentially Limit Adoption

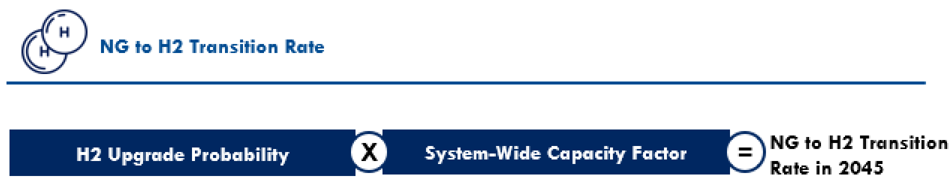
The factors considered included:

1. Hydrogen conversion costs: There remains uncertainty around CapEx, OpEx and additional site upgrade costs. Costs could vary depending on speed to technical viability and learning curves of the various technologies underpinning the transition.
2. Rate of transition to hydrogen: OEMs have announced plans to manufacture turbines that can run on 100% hydrogen fuel by 2030, but timelines may shift in the future.
3. Supply uncertainty: If there is uncertainty in the availability of clean renewable hydrogen, potential off-takers may delay making the necessary investments to transition their operations, resulting in a slower ramp-up than estimated.

4. Availability of alternatives: In the power generation sector, there are a variety of decarbonization alternatives to choose from, including renewables, hydrogen, carbon capture and battery storage. The advancement of non-hydrogen alternatives may impact investment decisions on hydrogen at the facility level.

Adoption Rates

Figure 8: Power Sector Adoption Rate Diagram



Hydrogen Upgrade Probability

A cost module uses the assumptions described below as well as detailed information on existing natural gas plants to make predictions on the decarbonization pathway a utility might choose for that facility. Options included retrofitting combustion turbines to utilize hydrogen, adding CCUS, replacing the capacity with batteries, or power purchase agreements. This module does not take into consideration any policy, regulation, or political factors. It is purely a simplified way of comparing the costs between each of the alternatives and creates a likelihood for each. However, these cost numbers will change on a plant-to-plant basis and each power plant will have other factors to consider as well when deciding how to reduce carbon emissions according to environmental regulations.

Cost estimates for a current gas plant to transition from 0 to 30% and 0 to 100% are provided for different ranges of GT sizes. These are based on Feasibility and Front-End Engineering Design (FEED) studies performed by EPRI based on knowledge from previous hydrogen demonstrations. Based on this data, curves were created to have a cost vs. Megawatt comparison that can be applied to each of the gas turbines in the SoCalGas district. The equation for curves was used to predict the CapEx investment needed to upgrade gas turbines in the SoCalGas service territory. As this study did not have the opportunity to get direct quotes from OEMs or others, the costs estimated here are subject to large potential variation. AACE cost estimates range from Class I to Class V, with Class V being the least accurate with –50% and +100% accuracy. These cost estimates may not be as accurate as Class V as limited information was used in their generation.

The main two capacity alternatives to hydrogen combustion considered for this study are batteries and carbon capture, utilization, and sequestration (CCUS). For the battery option, it was assumed that it costs $2,000,000 per MWh for the CapEx cost of battery installation. These battery costs are based off a 2023 EPRI feasibility study that performed a class IV cost estimate for a 1MW/1MWhr battery configuration[69]. The OpEx cost of the battery option was based on the cost of electricity to charge the battery and assumed this occurred during off-peak periods. For the CCUS option, a U.S. DOE Office of Scientific and Technical Information (OSTI) report was used for costs.[70]

The 95% carbon capture case on an F-class machine was used for cost data. Specifically, the cost data is shown on page 613. Although these costs in the OSTI report are for new plant builds, the $/kW of the “Flue Gas Cleanup” and “Feedwater & Miscellaneous BOP systems” were taken and added together to best estimate what the upgrade cost might be to achieve CCUS at an existing plant. As this Demand Study analysis is based on retrofits to current turbines, the other line items in the OSTI cost table were excluded as they are relevant for new plants and not applicable for retrofits.

Hydrogen upgrade probability analysis compares the estimated CapEx costs and selected OpEx costs of the alternatives. Fuel costs of alternatives were included in OpEx costs, as well as the cost of transport and storage for CCUS. The overall logic of this module is that each plant will need to choose one of the three options listed above. Each option is compared to the cost of purchasing power over the same time horizon as this is what would happen in the future if the plants chose none of the three conversion options and chose to shut down. Hydrogen conversion, Battery power, and CCUS all start with an equal chance of being selected. This percentage is adjusted based on the cost over the time horizon compared to the other alternatives. If the alternative is more cost-effective than other options, it will increase in likelihood and vice versa for the opposite scenario.

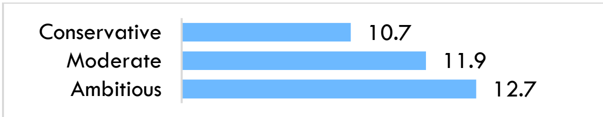
This is a simplified way of calculating financial predictions and will be heavily based on each power plant. This is intended as an overall comparison between technologies for the region served by SoCalGas.

[69] Feasibility Study for Green Hydrogen Generation and Cofiring Hydrogen in an Aeroderivative Gas Turbine: Solar, Battery Energy Storage System, Desalination, Electrolyzer, Hydrogen Storage, Natural Gas Blending, and LM2500 Gas Turbine Operation (epri.com) https://www.epri.com/research/products/000000003002025998

[70] Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity (Technical Report) | OSTI.GOV https://www.osti.gov/biblio/1893822

Once the hydrogen upgrade probability is determined based on the above cost analysis, it is multiplied by total current capacity in SoCalGas' service territory to determine the total projected hydrogen capacity in 2045. The results are shown below:

Figure 9: Projected Hydrogen Capacity by 2045, GW



Capacity Factor

A range of "what-if" capacity factor scenarios were evaluated to determine the total hydrogen demand for power generation. Capacity factors were not modelled and were instead input directly to understand what the potential demand could be across a range of different capacity factors. The probability of each capacity factor was not evaluated. The specific capacity factors used were based on the below:

Table 18: Capacity Factor Scenarios

Scenario	Source	Potential "What If" Scenario
Conservative (C.F. of 10%)	Based on feedback from various market participants (OEMs and operators)	Decline in future capacity factors due to a large shift from power plants to other intermittent renewables
Moderate (C.F. of 20%)	Based on a midpoint between conservative and ambitious scenarios.	Decline in capacity factor associated with combustion turbines from today, however the capacity factor is larger than in the conservative scenario reflecting increased dispatchability needs.
Ambitious (C.F. of 30%)	Based on historical EIA natural gas capacity factor data[71] in California, which has fluctuated between roughly 25%-35% since 2010. Past capacity factors were calculated from generation (table 5) and capacity (table 4) tabs in the linked EIA dataset	Reflects a potential future where hydrogen capacity factors remain similar to past California gas capacity factors

Hydrogen Transition Rate

The future hydrogen capacity and the future hydrogen capacity factor described above are used to calculate the predicted generation from hydrogen in 2045. The calculated level of generation from hydrogen is taken as a percentage of current generation to determine the % of transition to hydrogen in 2045. From here, an adoption curve was developed to reach yearly transition rates. A key inflection point of this curve is 2030, which is the projected milestone for technical feasibility and business readiness. At this

[71] State Electricity Profile (eia.gov)
https://www.eia.gov/electricity/state/california/state_tables.php

point, plants begin progressively moving from low levels of blending to 100% hydrogen, thus causing a slope change in hydrogen demand starting at 2030.

Total Hydrogen Demand

Once yearly transitioned rates have been developed, these transition rates are applied to current consumption to determine yearly hydrogen demand. The formula used for this is below:

$$H2\ Demand = \left(\left(\frac{Current\ MMBTU\ of\ natural\ gas\ consumption}{MMBTU\ per\ ton\ of\ H2}\right) * Efficiency\ ratio\ of\ future\ turbine\ usage\ to\ current\right) * Hydrogen\ Transition\ Rate$$

Current efficiency at a turbine level is used as the starting point for future hydrogen demand, as the source data of natural gas consumption by MMBTU reflects current efficiency. A ratio of 80% is used to reflect the difference in operation and uses between today's turbines and future turbines running on hydrogen. This ratio reflects the assumption that if there is a higher percentage of units being run as flexible units filling demand when renewables are offline, most units (if not all) would be run in single cycle; therefore, the average system-wide efficiency of hydrogen turbines in the future would decrease to around 80% of current natural gas turbine efficiencies. This ratio is based on SME input and analysis.

The conversion of current natural gas consumption at plants in SoCalGas' service territory to hydrogen and the multiplication by the hydrogen transition rate (developed based on hydrogen upgrade probability, capacity factor, and additional adoption factor milestones) delivers the final demand output.

Industrials

Methodology

The potential annual hydrogen demand was quantified for the following industrial sectors:

Table 19: Industrial Subsectors

Sector Priority	Sub-Sector	Hydrogen Opportunities
Primary	Refineries	• Fuel Switching • Direct Process Use for Legacy Fuels • Renewable Diesel and Sustainable Aviation Fuel (SAF) Production
Primary	Food and Beverage	• Fuel Switching
Primary	Metals (Primary Metals and Fabricated Metals)	• Fuel Switching
Primary	Stone, Glass, Cement	• Fuel Switching
Primary	Cogeneration	• Fuel Switching
Secondary	Paper	• Fuel Switching
Secondary	Chemicals	• Fuel Switching
Secondary	Aerospace and Defense	• Fuel Switching

There are three main analysis methodologies for calculating hydrogen demand in the model.

1. Fuel switching from natural gas to hydrogen for non-cogeneration use cases (including refining).
2. Fuel switching from natural gas to hydrogen for cogeneration.
3. Adoption of clean renewable hydrogen at refineries for direct process usage in petroleum refining processes and renewable fuels production.

The methodologies used to determine hydrogen demand for each of these three types of end-uses differs and is described in the three sections below.

Fuel switching from natural gas to hydrogen for non-cogeneration use cases (including refining)

The following methodology steps were taken to determine the addressable natural gas demand for fuel switching for non-cogeneration sub-sectors.

Step 1: Base Natural Gas Demand

For all sectors, the base natural gas demand is determined by the current greenhouse gas emissions from natural gas and associated natural gas usage in that sub-sector in SoCalGas' service territory. In order to identify the facilities in the SoCalGas territory, industrial facilities are identified through a combination of the CARB Pollution Map[72] and the EPA FLIGHT dataset[73] (Facility Level Information on Greenhouse Gas Tool). Both tools track GHG emissions from large emissions facilities that are required to or opt to participate in the emissions reporting required by CARB or the EPA.

For most sub-sectors, the CARB Pollution Map is used to identify the base facility emissions. While FLIGHT also identifies high emission-producing facilities, the CARB dataset has a lower minimum threshold for emissions reporting and better captures all large facilities that are potential users of hydrogen. However, FLIGHT captures more information per facility and is used in each sub-sector in different manners depending on the characteristics of that sub-sector. For all fuel switching opportunities, the initial step in determining the base natural gas demand is to estimate the CO2 equivalent emissions from natural gas.

Refineries: Only the FLIGHT dataset was used to determine the natural gas usage from non-cogeneration refinery demand for natural gas. This dataset was used because it contained a detailed break-down of how much natural gas was used for cogeneration and how much was used for refinery processes. The natural gas volumes for refinery processes were separated and used to assess the fuel-switching portion of the refinery demand.

Food and Beverage: The CARB dataset is used to identify the total number of facilities in the food and beverage sectors and the total CO2e GHG emissions. The FLIGHT dataset consists of a subset of these facilities. The FLIGHT data set is used to estimate the estimated percentage of emissions in this sector that stem from natural gas: 99.99%. This figure is then applied to the facility – level GHG emissions identified in the CARB dataset.

Metals: The CARB dataset is used to identify the total number of facilities in the metals and the total CO2e GHG emissions. The FLIGHT dataset consists of a subset of these facilities. The FLIGHT data set is used to estimate the estimated

[72] CARB Pollution Mapping Tool https://www.arb.ca.gov/carbapps/pollution-map/
[73] EPA Facility Level GHG Emissions Data https://ghgdata.epa.gov/ghgp/main.do?site_preference=normal

percentage of emissions in this sector that stem from natural gas: 100% This figure is then applied to the facility – level GHG emissions identified in the CARB dataset.

Stone, Glass, and Cement: The CARB dataset is used to identify the total number of facilities in the stone, glass, and cement sector and the total CO2e GHG emissions. The FLIGHT dataset is not utilized in the capture of total emissions as the EPA has different reporting requirements for cement facilities, which are not captured in FLIGHT. Since emissions in this sector stem from natural gas consumption and additional production processes, different assumptions are utilized to determine the estimated GHG emissions from natural gas combustion.

- Cement: 40% of emissions are due to combustion[74]
- Stone and Clay: 100% - natural gas is not assumed to be used in a meaningful way in direct processes.
- Glass: 75% - Average natural gas emissions due to glass production in California as cited in FLIGHT

Paper: The CARB dataset is used to identify the total number of facilities in the paper sector and the total CO2e GHG emissions. EPA's FLIGHT captures cogeneration demand for most paper facilities in SCG territory. For facilities, data is leveraged from Manufacturing Energy Consumption Survey (MECS) to estimate the percent of total natural gas consumption by end use. MECS is a national survey conducted by the US Energy Information Administration (EIA) to collection information on the US manufacturing establishment and their energy-related characteristics and consumption. As part of this survey, natural gas end use is collected by NAICS identified sectors. In the survey, energy usage is broken out into five categories, including Combined Heat and Power (CHP). For facilities where cogeneration demand is not identifiable, the percentage of natural gas used for cogeneration, paper industry wide, is multiplied by the total natural gas emissions to identify emissions from cogeneration.

Chemicals: The CARB dataset is used to identify the total number of facilities in the chemicals sectors that do not produce industrial gases (hydrogen) and the

[74] Alternative Clinker Technologies for Reducing Carbon Emissions in Cement Industry: A Critical Review - PMC (nih.gov)
https://www.ncbi.nlm.nih.gov/pmc/articles/PMC8746203/

total CO2e GHG emissions. All emissions are assumed to be from natural gas consumption per SME input.

Aerospace and Defense: Facilities in this sector are identified by using publicly available information, specifically focusing on near and around El Segundo, CA. Natural gas usage was identified for one of the major facilities using the CARB dataset and assumed to be similar for the remaining facilities, with the exception of a secondary aerospace manufacturing facility which was assumed a smaller value closer to similar sized manufacturing facilities.

MMBTU Conversion – All Sectors: EIA has developed a methodology to convert CO2 emissions of natural gas to million BTU utilizing fuel rates. Per this methodology, ~117 pounds of CO2 from natural gas emissions are equivalent to 1 MMBTU.

Step 2: Natural Gas Demand by Heating Use Case

Once the current natural gas usage has been determined based on emissions data, the US Energy Information Administration (EIA) Manufacturing Energy Consumption Survey (MECS)[75] is used to understand how current natural gas usage is split across end-uses. As described earlier, the MECS is a national survey conducted by the EIA to collection information on the US manufacturing establishment and their energy-related characteristics and consumption. As part of this survey, natural gas end use is collected by NAICS identified sectors. In the survey, energy usage is broken out into five categories:

- Indirect Uses (boilers): Natural gas does not provide direct heat but provides heat to water which is then used to provide heating through steam or hot water.
- Direct Process Heat: Natural gas is used to provide heating to industrial processes by heating air or the workpiece directly.
- Direct Non-Process Heat: Natural gas is used to fuel heating systems that do not directly contribute to industrial processes (e.g., HVAC)
- Feedstock: Natural gas is used as feedstock for industrial processes
- Indirect Uses - Combined Heat and Power (CHP): Provides on-site electric power, heating, and cooling.

[75] U.S. Energy Information Administration - EIA - Independent Statistics and Analysis https://www.eia.gov/consumption/manufacturing/

The survey provides the total energy usage across the industry level of granularity. The percentage of natural gas usage for an industry can be used and applied to the base natural gas demand for a sub-sector. However, per SME input, many facilities report boilers as CHP in survey results, not distinguishing between the two indirect natural gas usages. Therefore, the percentage of natural gas usage identified for CHP in MECS is added to the percentage of natural gas usage identified for "Indirect Uses (Boilers)" in MECS.

Table 20: Food & Bev MECS Data

2021 Estimated Natural Gas Consumption (Trillion BTU)	NAICS 311: Food Manufacturing
Indirect Uses (Boilers)	19.51213828
Indirect Uses (CHP)	36.15484447
Direct Process Uses	23.95975804
Direct Non process Uses	0.57388642
Feedstock	2.00860247

2021 Estimated Natural Gas Consumption (%) – CHP Included	NAICS 311: Food Manufacturing
Indirect Uses (Boilers)	23.7%
Indirect Uses (CHP)	44.0%
Direct Process Uses	29.1%
Direct Non process Uses	0.7%
Feedstock	2.4%

2021 Estimated Natural Gas Consumption (%) – CHP Excluded	NAICS 311: Food Manufacturing
Indirect Uses (Boilers)	67.7%
Indirect Uses (CHP)	0.0%
Direct Process Uses	29.1%
Direct Non process Uses	0.7%
Feedstock	2.4%

The base annual natural gas demand, in MMBTU, per heating use case is determined by multiplying the base demand by the estimated breakdown of natural gas usage for a particular sub-sector. For some sub-sectors, there may be further breakdown of natural gas usage as there are differing MECS percentages within a sub-sector. For example, in the “Metals” sub-sector, the base natural gas annual demand is split into “Primary Metals” and “Fabricated Metals” as MECS identified different breakdowns of heating use-cases for each category.

Step 3: Industry Growth Rate

For each scenario, there are different assumptions utilized on how base natural gas demand will increase or decrease over time.

For the conservative scenario, there is no projected increase in energy consumption in that category to reflect a stagnant market demand for that category’s production output.

For the moderate and ambitious scenario, for non-refineries and non-cogeneration sub-sectors, the study estimates industry growth rates using a dataset from EIA’s Annual Energy Outlook, entitled “Industrial Sector Macroeconomic Indicators”[76]. The dataset estimates the value of production in each sub-sector from 2022 to 2050. For both scenarios, dataset used in the study was filtered to focus on the “Pacific” market and represent a high industrial growth scenario. The dataset provided the total value of shipments in 2012 dollars and the growth/decline between the total value of shipments for a specific sub-sector or sub-sector category was taken to be the industry growth rate.

When more detailed breakdowns of categories within sub-sectors were available, they were leveraged. For example, the facilities covered in the “Metals” sub-sectors were broken into “Primary Metals – Steel”, “Primary Metals – Aluminum”, and “Fabricated Metals”. The industry growth rates were then pulled for each category and then applied to the base natural gas demand, split out by heating use case. In instances where there were more industrial growth rate data available than MECS category splits, the natural gas demand was further broken out so that the industry growth rates could be applied appropriately to the natural gas demand from each category. The industry growth rate is then applied to the

[76] U.S. Energy Information Administration - EIA - Independent Statistics and Analysis https://www.eia.gov/outlooks/aeo/data/browser/#/?id=34-AEO2023&region=1-9&cases=highmacro&start=2021&end=2050&f=A&linechart=highmacro-d020623a.2-34-AEO2023.1-9&map=highmacro-d020623a.4-34-AEO2023.1-9&chartindexed=0&sourcekey=0

base natural gas, with the assumption that natural gas consumption will increase or decrease at the same rate as the total volume of shipments.

For refineries, EIA's Annual Energy Outlook demand was also leveraged, including a table in the report, "Table 24. Refining Industry Energy Consumption" since it provided specifically more information on natural gas usage rate changes. The high economic output scenario was utilized. The difference in total natural gas consumption by the industry, per annum, was then taken to be the industry growth rate.

Step 4: Electrification Adjusted Demand

In order to determine the total addressable market for hydrogen, any potential natural gas demand that can be electrified is removed.

SME input from EPRI was leveraged to estimate the electrification adoption rate of each heating use case by the year 2050. The 2050 adoption rate is then multiplied by a scale which begins at "0" in the year 2021 and then reaches "1" in 2050 at a linear scale.

Table 21: Electrification Potential

Heating Use Case	2050 Electrification Adoption
Indirect Heat (Boilers)	5%
Direct Heating Application	20%
Direct Non process Uses	80%
Feedstock	0%

There are two exceptions: Electrification adoption in 2050 for Food & Beverage boilers is assumed to be 20% per SME input, and direct heating in primary metals is assumed to be 5% per SME input.

The electrified demand for a given year is determined by multiplying the growth-rate adjusted natural gas demand by the electrification adoption rate and this is subtracted from the total natural gas demand to determine the remaining natural gas demand that can be addressed by hydrogen for fuel-switching.

Fuel switching from natural gas to hydrogen for cogeneration

The methodology for hydrogen demand from fuel switching for cogeneration follows a different methodology than and is not related to the methodology described in the fuel switching for non-cogeneration section above. In order to identify the number of cogeneration facilities and annual natural gas demand per facility, EIA Form 923 was leveraged. The survey form collects detailed electric power data – monthly and annually – on electricity generation at the power plant level, specifying which plants are cogeneration facilities. The survey provides the natural gas demand per facility. The survey results from the year 2021 were used for this study[77]. Methodology and assumptions used to determine total electricity demand from cogeneration plants was assumed to be consistent with the power generation sector across all years and for all scenarios for the purpose of this study.

Adoption of clean renewable hydrogen at refineries for direct process usage in petroleum and renewable fuels refining

The methodology for hydrogen demand from direct process usage in petroleum and renewable fuels refining is not related to the methodology for hydrogen demand from fuel switching. Demand for direct process hydrogen is estimated based upon typical mass consumption of hydrogen (kg) per volume of total throughput, in the case of petroleum refining, or produced fuel, in the case of renewable diesel and sustainable aviation fuel, observed at existing analogous facilities.

Hydrogen Demand for Petroleum Production

The first step in determining direct process hydrogen usage for petroleum refineries is to determine total annual crude oil and feedstocks throughput for the refinery in barrels. For refineries in SCG territory net annual throughput for 2021 was calculated based on refinery nameplate capacity information obtained from the California Energy Commission (CEC)'s California Petroleum Markets report, dated July 14, 2020, and annual utilization rates obtained from CEC's Petroleum Watch 2021[78]. Based on the latter, it is notable that refineries in Southern California operate at 89% utilization, outpacing the state average of 80%.

[77] Form EIA-923 detailed data with previous form data (EIA-906/920) - U.S. Energy Information Administration (EIA) https://www.eia.gov/electricity/data/eia923/
[78] https://www.energy.ca.gov/data-reports/reports/petroleum-watch

Future year net throughput estimates are based on extrapolation of 2021 volumes with the following, SME provided fuels market demand estimates applied.

- 2021: 0%
- 2030: -5%
- 2040: -25%
- 2050: -50%

For this analysis, fuels market demand destruction was scaled linearly between the 2030, 2040, and 2050 anchor points.

Total direct process hydrogen demand was determined based upon calculated total refining throughput with typical, aggregate hydrogen consumption rates for desulfurization and hydrocracking applied (source data from a study by Praxair[79] and the California Energy Commission).

This total direct process hydrogen demand is subsequently multiplied by the estimated percentage of H2 demand outsourced by refineries (sourced from the EIA), to determine the split between outsourced demand and internal demand.

Hydrogen Demand for Renewable Diesel Production

Direct process hydrogen demand for renewable diesel was determined based upon producer sourced annual production volumes, which were then converted from barrels to kilograms using product densities sourced from the University of Missouri to determine total annual mass of renewable diesel produced. Estimated hydrogen consumption ratios – kilogram of hydrogen consumed per kilogram renewable diesel produced – were then applied to the calculated total annual mass-based renewable diesel production to determine the total annual direct process hydrogen demand in kilograms. [78]

Hydrogen Demand for Sustainable Aviation Fuel (SAF)

Total volume of SAF produced was calculated by multiplying total jet fuel production by the percentage of petroleum refinement transitioning to SAF, projected at 25% of the yearly reduction of petroleum production. This yearly

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[79] https://assets.linde.com/-/media/global/corporate/corporate/documents/sustainable-development/climate-change/the-role-of-hydrogen-in-removing-sulfur-from-liquid-fuels-w-disclaimer-r1.pdf

reduction of petroleum production is set equivalent to the refinery industry growth rate based on EIA Energy Outlook projections[80]. This figure was determined through consultations with industry experts. The result is then multiplied by the tonne H2 per barrel of SAF conversion ratio of 0.005 tonnes of H2/barrel of SAF[81] to give the projected hydrogen demand.

Assumptions

Addressable Market

- Only large facilities have been considered as potential end users in this phase. Large facilities are broadly defined as facilities that have significant natural gas footprint to be included in public emissions reporting data bases or additional facilities in the region identified by subject matter experts.
- Facilities built in conjunction with existing providers of hydrogen (e.g. Air Liquide, Air Products, PraxAir) are not considered to be potential end-users of new hydrogen demand.
- Existing use of grey hydrogen is not considered to be existing demand under the clean renewable hydrogen constraints of the Angeles Link pipeline and hydrogen projections do not include grey hydrogen demand. Only clean, renewable hydrogen use is projected in the demand study. However, clean renewable hydrogen demand arising from the potential switching of grey hydrogen to clean renewable hydrogen at refineries is included in the demand quantities in the ambitious scenario.
- Chemical facilities that currently produce hydrogen are not considered to be potential end-users of new hydrogen demand.
- All facilities in SoCalGas territory and territories where SoCalGas provides wholesale natural gas are considered potential adoptees of hydrogen for this study.

Hydrogen Adoption Factor Assumptions

<u>Legislation</u>

Senate Bill 596:

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[80] U.S. Energy Information Administration - EIA - Independent Statistics and Analysis https://www.eia.gov/outlooks/aeo/data/browser/#/?id=35-AEO2023&cases=ref2023&sourcekey=0

[81] Based on interviews with subject matter experts across industry.

- Requires cement producers to reduce carbon emissions by 40% by 2030 and sets a target for 100% decarbonization by 2045[82]

Technical Feasibility

- For most industrial facilities within SoCalGas's territory, the primary opportunity for hydrogen will be fuel switching for process heat/steam, switching from natural gas-based combustion to hydrogen-based combustion technology.
- An estimated 40% of emissions from the cement industry are from combustion, the remaining emissions are from the production of clinker.
- Hydrogen adoption for industrial and commercial sited cogeneration turbines is expected to follow the same levels of technical feasibility growth as the other cogeneration turbines described in the Power sector section of this report.

Sector Growth

- In the conservative scenario, industry growth is 0% for all sub-sectors as no additional increase in industrial goods production is expected.
- In the moderate and high scenario, natural gas usage is expected to increase in-line with increase in industrial goods production per sub-sector, as forecasted by EIA's Annual Energy Outlook Macroeconomic Indicators dataset[83]
- No additional increase in demand at cogeneration facilities across all scenarios

Adoption Rates

Fuel Switching – Non-Cogeneration

For fuel switching applications of hydrogen, fuel switching adoption rates were evaluated by each end-use case of natural gas in industrial facilities. Subject matter expertise was utilized to evaluate three key adoption parameters over the course of time: Technology Feasibility, Alternatives, Commercial Availability (Capital Investments and Performance Impact), and Business Readiness. Alternatives was separated out from other adoption factors and listed as its own factor instead of legislation due to the lack of legislation in industrial sectors. Legislation has been included as a consideration where legislation exists. The adoption rate status was evaluated at three points in time:

- Short Term: 2025 – 2030

[82] Bill Text: CA SB596 https://legiscan.com/CA/text/SB596/id/2434232
[83] U.S. Energy Information Administration - EIA - Independent Statistics and Analysis https://www.eia.gov/outlooks/aeo/data/browser/

- Medium Term: 2030 – 2040
- Long Term: 2040+

A description of the four adoption rate parameters is below:

- Technology Feasibility: Measures current stage of technology development and expected future technological feasibility
- Alternatives: Measures the strength of decarbonization alternatives such as CCUS that may be used instead of hydrogen for decarbonization and reduce hydrogen adoption
- Commercial Availability: Measures the cost level of hydrogen adoption and equipment upgrades compared to legacy fuels
- Business Readiness: Lag parameter added to determine final adoption rates to reflect business timelines

At each time segment, for each heating use-case per sub-sector, a (Low/Medium/High) rating was assigned to each adoption parameter. These H/M/L categories were each given a percentage out of 100%, with adoption rate parameter-specific percentages described below. Each adoption factor was weighted equally at 33%, and a hydrogen adoption rate for each subsector was determined based on a weighted average of the three adoption rate parameters.

Table 22: Industrials Adoption Rate Parameters

Parameter	Rating	Definition
Technology	Low	The technology is currently in emerging stages of development
	Medium	The technology has been proven but is not commercially available (not proven at scale)
	High	The technology is readily commercially available
Alternatives	Low	Low likelihood of hydrogen adoption due to high prevalence of alternatives
	Medium	Medium likelihood of hydrogen adoption due to some prevalence of alternatives
	High	High likelihood of hydrogen adoption due to lack of viable alternatives
Commercial Availability (Capital	Low	The switch to increased hydrogen adoption is less cost competitive compared to legacy technology, excluding fuel costs

Investments and Performance Impact)	Medium	The switch to increased hydrogen adoption is equally as cost competitive compared to legacy technology, excluding technology costs
	High	The switch to increased hydrogen adoption is more cost competitive compared to legacy technology, excluding technology costs

Technology (Low: 25%, Medium: 50%, High: 75%)

Even in emerging stages of technology development, there are assumed to be some potential off takers of hydrogen technology in pilot or limited deployment capacity. However, at even high technology readiness, there will be some facilities that will not be willing to invest in hydrogen due to reasons such as current equipment not yet having reached retirement age and general lags in technology adoption for certain companies.

Alternative: Option 1 – High CCUS Favorable Facilities (Low: 0%, Medium: 25%, High: 50%)

This alternative option is utilized for adoption rate analysis with high favorability of CCUS (stone, glass, cement, primary metals). Given that CCUS is a viable solution in these industries, it is assumed that companies looking to decarbonize will choose between either hydrogen and CCUS with a split in adoption between the two technologies, lowering the potential market for hydrogen and reducing adoption rate. This is reflected in the limited range from 0-50% between low and high.

Alternative: Option 2 – Low CCUS Favorable Facilities (Low: 0%, Medium: 50%, High: 100%)

This alternative option is utilized for adoption rate analysis with low favorability of CCUS (Refineries, Food & Beverage, Fabricated Metals, Secondary Sub-Sectors). In these sectors, given the lack of viable decarbonization alternatives, hydrogen would proceed to full adoption in a high adoption rate scenario reflected in the range of 0-100% between low and high.

Commercial Availability (Capital Investments & Performance Impact) (Low: 20%, Medium: 50%, High: 80%)

In an environment where 100% hydrogen technology is not competitive with existing equipment, there is some adoption as hydrogen can be blended up to 20% in fuel switching with natural gas applications without significant infrastructure change.

However, even in an environment where 100% hydrogen technology is very cost competitive, there will not be 100% adoption due to the capital investments required to integrate new technology versus continue extension of existing assets.

Table 23: Industrials Adoption Rate Weights

Fuel Switching (Refineries, Food & Beverage, Fabricated Metals, Secondary Sub-Sectors)			
Weights	33%	33%	33%
	Tech	**Alternatives**	**Commercial Availability (Capital Investments & Performance Impact)**
Low	25%	0%	20%
Medium	50%	50%	50%
High	75%	100%	80%

Fuel Switching (Stone, Clay, Glass, & Cement, Primary Metals)			
Weights	33%	33%	33%
	Tech	**Alternatives**	**Commercial Availability (Capital Investments & Performance Impact)**
Low	25%	0%	20%
Medium	50%	25%	50%
High	75%	100%	80%

Business Readiness

A logistic delay function is then applied to the base adoption rate in a given year to integrate the timeline when existing equipment is reaching end of life and facilities are ready to evaluate whether they will switch to new hydrogen-based technology. The lag terms are the following, per heating use case:

- Estimated Lag Term for Boilers and High-Direct Process Heat: 20 years.
- Estimated Lag Term for Direct Non-Process Heat: 15 years.

The formula for the final lag adjusted annual adoption rate, starting in the year 2025 is:

$$Adoption\ Rate_{2024} = 0\%$$

$$Annual\ Adoption\ Rate_x = \left(1 - \frac{1}{Lag\ Term}\right) * Annual\ Adoption\ Rate_{x-1} + \frac{Step\ Function\ Adoption\ Rate_x}{Lag\ Term}$$

Adoption Rate Basis – Metals

Technology (Primary and Fabricated Metals):

Table 24: Metals Adoption Rates - Technology

	2025 – 2030	2030 - 2040	2040+
Boilers	Low	Medium	High
Direct Process Heat	Medium	High	High
Direct Non-Process Heat	Medium	High	High

Rationale:

Metals industries in SoCalGas's service territory consist primarily of three types: back-end metal forming operations for steel and aluminum; primary engineered structural shapes (sheets, strips, rings, bars, beams, castings and extrusions) in the primary metals categories; and wide variety of metals fabrication processes supporting robust assembly and sub-assembly supply chains.

The primary fuel end-uses in these sectors generally fall into direct process heating to increase malleability prior to forming operations in the primary space and to drive metallurgical processes to generate the needed hardness, strength, dimensional stability and machinability characteristics of the metal components in downstream secondary processing. A second important yet smaller source of final energy demand is in the production of steam used for cleaning, heating of various process solutions involved in chemical surface treatments and for mill and shop space-heating applications.

A transition to hydrogen for these purposes would require changes in the design of several equipment types, including valve trains, metering, burners and refractories. Flame speed is an issue with traditional pre-combustion burner mixers as the flame can flash backward resulting in loss of ignition and risking dangerous explosion events. Infrared-emitting hydrogen-capable burners are under development that avoid flashback and concerns over thermal NOx formation as are a family of fuel agnostic intelligently modulated burner designs that have a goal of reducing the risk of availability and pricing fluctuations across a variety of potential gaseous and liquid fuels. These designs serve to lessen the risk of migration from hydrogen blends to full hydrogen adoption avoiding further expense in the combustion systems. Beyond retrofits, purpose built 100% hydrogen furnace, oven and boiler systems are being modelled and will be in demonstration over the next 3 to 5 years providing metals industry customers with more efficient by-design hydrogen-fueled process heating alternatives.

Hydrogen-capable valve trains and piping are available today. Burner models and designs are at different stages based on the vendor and application. Some are in demonstration today and could be in a position to gear up for product launch in the next 3-5 years. Flame management and advanced combustion controls systems are less certain as are any materials demonstrations needed for high temperature alloys and refractories. Ongoing government funding and demonstration projects should have these subsystems ready for commercialization in the 5–10-year timeframe.

Production processes in the metals industries will have to change in several ways to enable 100% hydrogen use. The potential for reduced net thermal efficiency of retrofit systems could result in lower throughput and process yields, which could only be overcome by installing additional burners into process heating equipment or increasing the physical burner heating capacity which could face physical limitations and would certainly add to the CapEx and OpEx requirements. More sophisticated process controls, flame management and hydrogen safety systems, including leak detection, may be required, adding to the risk mitigation cost.

Additionally, systems to reduce thermal NOx formation may be required. In most applications it will be necessary to execute careful process change management systems to ensure that product quality is not adversely impacted by flame characteristics such as temperature, length, irradiance, speed, and the new slate of combustion products including water and residual hydrogen.

These are time consuming processes that require extensive testing and proof of process performance to rigorous international product quality standards. Similarly, impacts on Mean Time Between Failure of critical heating system components like burners, tubes, refractories, shells sensors and controls must all be assessed to establish any maintenance cost and downtime penalties that must be accounted for in economic justification calculations. These factors individually can add two to five years to new process adoption and combined serve to dramatically flatten the slope of the adoption curve for these assets which are expected to serve a 10 - 20-year operating life or longer.

Regarding operational characteristics, once the gas fuel leaves the city-gate at distribution pressures, though somewhat elevated compared to hydrocarbon fuels, the pressures are well within comfortable ranges for equipment operators and are very low at the point of application where mixing with air (or oxygen) on its way to the burner-tip. Because of the much lower volumetric density a combination of larger piping size and pressure may be needed to deliver an equivalent btu/hr rated heating system for a given furnace application. If early adoption depends on in situ blending of hydrogen with natural gas, a properly designed and stable blending unit will add to the investment and operation requirements. Industry readiness varies for different levels of blending between 20 and 30% for different elements of the combustion system and other equipment components. Hydrogen combustion also produces a water laden effluent which can impact process and emissions controls, refractory performance and life and products. Impacts of seasonal variation of natural gas heating values with respect to hydrogen blends has not been studied and will need to be understood in terms of process tolerances. This is likely to become less important with higher percentage hydrogen blends.

Alternatives (Primary and Fabricated Metals):

Table 25: Metals Adoption Rates: Alternatives

	2025 – 2030	2030 - 2040	2040+
Boilers	Low	Low	Low
Direct Process Heat	High	Medium	Medium
Direct Non-Process Heat	Low	Low	Low

Rationale:

Direct electrification through resistive/convective, induction heating and to a lesser degree infrared technologies will acquire larger portions of this process heating demand market due to the highly competitive thermal efficiencies of radiant heating, competitive capital costs, alignment with LEAN manufacturing principles (single piece flow, JIT, etc.) and mature technology availability for the past 20+ years.

The other alternative to consider is in situ or within-cluster carbon capture and sequestration or use. Because the current technologies are focused on utility scale emissions effluents, there is not an aggressive effort to downward integrate CCUS at a scale that is economically viable for metals processing furnaces. The effluent streams contain significant excess water and nitrogen that dilute the CO2 stream and make it expensive to concentrate and collect/compress across multiple sites necessary to adapt current system designs. Moving toward oxy-firing might improve the financials but a price penalty for O2 must be paid on the front end and O2 is a substantially more hazardous process gas to manage than hydrogen so risk mitigation across multiple sites would be a concern.

The remaining unelectrified demand is technically convertible to hydrogen combustion systems that could gain share in the higher temperature and high aggregate Btu/hr process thermal demand rates. This is more likely to occur in larger integrated processing facilities where hydrogen supply and associated safety systems, codes and standards and operational practices can be effectively institutionalized. These system-level changes, retrofit costs and workforce retraining costs will provide inertia in the market sub-segments that exhibit a wide dispersion of small to mid-sized enterprises. A recalcitrance level of up to 20% in adoption of hydrogen as a process heating fuel may occur toward the end of the planning period.

Similarly, steam which generally constitutes 20-25% of final energy in primary metals facilities and lower percentages in metals fabrication are convertible to direct electrification options through electrode and medium voltage boilers that are commercially available today. Hydrogen-based combustion systems to retrofit existing boilers in the upper end of the industrial boiler range are under development and demonstrations are eminent. It is expected that the steam boiler demand for steam-based process heat that is not electrified will be fully convertible to hydrogen combustion systems for these industries. These applications are likely to track the adoption profile of the base process heating demand as described above since those conversions will be simplified by the implementation of in-plant hydrogen supply infrastructure and workforce capabilities.

Commercial Availability (Primary and Fabricated Metals):

Table 26: Metals Adoption Rates – Commercial Availability

	2025 – 2030	2030 - 2040	2040+
Boilers	Low	Low	Low
Direct Process Heat	Medium	Medium	Medium
Direct Non-Process Heat	Low	Low	Low

Rationale:

Cost and performance characteristics of hydrogen capable burner systems are the subject of current research studies. It is expected that valve trains, piping, combustion controls, flame management systems, leak detection, burners, and refractories and emissions mitigation systems may all experience long term higher cost when compared with incumbent fossil fuel alternatives.

Some of the primary barriers that stand in the way of a hydrogen transition in the metals industry are a combination of retrofit and replacement costs, uncertainty of ultimate process performance, lack of successful demonstrations, and the viability of low-carbon alternatives.

The servicing of additional capital/debt associated with retrofits and higher cost purpose-built equipment and potential thermal efficiency penalties may diminish the financial feasibility in the short to medium term without significant incentives or regulatory pressure.

Metal manufacturers are conservatively managed businesses in highly competitive markets. Products tend to be commoditized quickly so competitive advantage often hinges on superior operational performance and tight control over all facets of production costs. As a result, there is an aversion to risk particularly when that risk touches the fundamental properties of their products. Process heating in the metals industry is fundamental to the physical/chemical and micro-structure properties of the industry's products so changes in process are slow and deliberate.

Adoption Rate Basis – Food & Beverage

Technology:

Table 27: Food & Bev Adoption Rates - Technology

	2025 – 2030	2030 - 2040	2040+
Boilers	Low	Medium	High
Direct Process Heat	Low	Medium	High
Direct Non-Process Heat	Medium	High	High

Rationale:

As fuel, hydrogen can be blended with or displace existing natural gas-use (fuel-switching) to generate process heat and steam. It could also be used for fuel cells to produce electricity. This electricity can then be used to power forklifts or back-up generation for refrigeration and HVAC systems.

When the direct combustion of natural gas is replaced by hydrogen, processes such as baking may be affected by increasing the humidity inside of ovens and hence affecting the color, density, and other properties of baked foods. In some cases, this may improve food quality,[139] but a great deal of change will likely be required to test and ensure the impacts of hydrogen flame and combustion byproducts on food quality and safety.

The feasibility of 100% hydrogen-use in the baking process remains to be determined, but some work in this space suggests up to 30% H2 blend does not pose a deterrent to equipment. When hydrogen is used in combustion, the same technical limitations apply to hydrogen blending with natural gas as it does for other industries. The usual limitations of burner capabilities and integrity of transportation lines apply.

For hydrogen use in process heating, the methodologies and processes for hydrogen use would generally be similar to natural gas, with adjustments made in BTU value for the different blends of hydrogen. Differences in piping size, controls and burner sizes and configurations may reach practical physical limits in which case productive capacity of a retrofitted system may need to be derated.

There are a handful of hydrogen equipment manufacturers in the food and beverage industry, including AMF Bakery Systems and RBS Oven Systems,[140] whose ovens can use hydrogen to bake a wide range of food products. These manufacturers offer complete replacements, rather than retrofits.

Alternatives:

Table 28: Food & Bev Adoption Rates - Alternatives

	2025 – 2030	2030 - 2040	2040+
Boilers	Low	Low	Low
Direct Process Heat	High	Medium	Medium
Direct Non-Process Heat	Low	Low	Low

Rationale:

For generating process heat in the food and beverage industry, electrification may be a favorable alternative to hydrogen. Food processing facilities have had some experience with direct electrification by implementing electrode steam boilers to satisfy facility-wide steam demand during off-peak periods through day ahead hourly electricity pricing tariffs. These systems offer considerable energy-related cost-savings for the end-user. These electrode boilers are a well-tested and available alternative for this industry and will likely have a jump-start on the market as decarbonization pressures build.

Industrial heat pumps, heat recovery heat pumps and heat recovery chillers are also likely to grow in this industry because of their cost of power advantages. Air impingement ovens offer greater efficiency than traditional convective heating ovens and should also be viewed as a competitive offering.[142]

The remainder of the fossil-fueled final energy in the food and beverage industry is associated with baking, drying and space conditioning applications. These involve low temperature and again are subject to heavy competitive pressures from electric technologies whose final energy thermal efficiencies are much higher than combustion-based systems. In this space, gas catalytic-style hydrogen-capable burners are under development but are yet to be demonstrated at scale. These units would possess some of the benefits of infrared cooking and baking but are 5 to 10 years from commercialization.

Commercial Availability:

Table 29: Food & Bev Adoption Rates – Commercial Availability

	2025 – 2030	2030 - 2040	2040+
Boilers	Low	Low	Low
Direct Process Heat	Medium	Medium	Medium
Direct Non-Process Heat	Low	Low	Low

Food and beverage facilities often run 24/7, with few idle periods apart from needed maintenance. Since installation of new hydrogen-based equipment can take up to a minimum of 3 months, there would be a significant performance impact in the short term and disrupt businesses with low margins.

<u>Adoption Rate Basis – Stone, Glass, and Cement</u>

Technology:

Table 30: Stone, Glass, Cement Adoption Rates - Technology

	2025 – 2030	2030 - 2040	2040+
Boilers	Low	Medium	High
Direct Process Heat	Medium	High	High
Direct Non-Process Heat	Medium	High	High

Rationale:

Some of the existing equipment used in cement production such as rotary kilns, burners, air-preheaters etc. may have to be modified to enable 100% H2 use. For example, the following systems will have to go through design modifications:

a. Combustion systems: Cement kilns and other high-temperature equipment would need modifications to accommodate the use of hydrogen as the primary fuel. Hydrogen has different combustion characteristics compared to conventional fuels like coal or natural gas. The burners, flame control mechanisms, and temperature management systems would need to be optimized for hydrogen combustion to ensure efficient and stable operations.
b. Storage and handling: Hydrogen has specific requirements for storage and handling due to its low density and high reactivity. Cement plants would need to invest in specialized hydrogen storage infrastructure, such as high-pressure or cryogenic storage tanks, to store the necessary quantities of hydrogen onsite. They may also choose to have on-site H2 production such as electrolyzers. Safety measures and protocols would need to be implemented to handle hydrogen safely.
c. Delivery systems: The existing fuel delivery systems in cement plants, which are designed for conventional fuels, may need modifications or replacement to accommodate the use of hydrogen. This includes pipelines, pumps, and valves, which must be compatible with hydrogen and capable of handling its unique properties.
d. Emissions control: Hydrogen combustion results in different emissions compared to conventional fuels. While hydrogen combustion does not produce carbon dioxide (CO2) emissions, it can lead to increased nitrogen oxide (NOx) emissions. Cement plants would need to incorporate appropriate emissions control technologies to minimize NOx and other pollutant emissions.

Alternatives:

Table 31: Stone, Glass, Cement Adoption Rates - Alternatives

	2025 – 2030	2030 - 2040	2040+
Boilers	Low	Low	Low
Direct Process Heat	Medium	Low	Low
Direct Non-Process Heat	Low	Low	Low

Rationale:

A significant decarbonization alternative in this industry is the application of carbon capture and use or sequestration technologies. Upwards of 55% of all CO2 emissions from cement production are process related whereas, roughly 35% results from fuel combustion. Either CCUS technologies must be applied throughout the industry to address process emissions, or the industry will have to undertake a wholesale change in its raw materials and processes (a pathway that is currently low TRL and fraught with technical and operational risks).

Direct electrification of the kiln faces these issues as well and furthermore concepts to electrically heat the kiln and any residual needs of the pre-calciner after heat recovery are only at bench scale development to date. Furthermore, though potentially highly efficient, electrification of cement production process heat would require tremendous amounts of electric power on a continuous and uninterrupted basis. The cost of electric infrastructure might well be cost prohibitive and achieving the continuous power flows from renewable sources on the grid would demand unprecedented levels of grid scale battery storage. An alternative being considered is dedicated advanced small nuclear reactors for this type of demand. Significant development, cost, safety, and regulatory hurdles will need to be overcome to make this pathway viable even toward the end of the planning horizon.

Commercial Availability:

Table 32: Refineries Adoption Rates – Commercial Availability

	2025 – 2030	2030 - 2040	2040+
Boilers	Low	Low	Low
Direct Process Heat	Medium	Medium	Medium
Direct Non-Process Heat	Low	Low	Low

Given the size of cement facilities, shifting to hydrogen - based equipment on a large scale would necessitate substation investments in hydrogen production, storage, and transportation infrastructure. However, lower levels of blending can still be achieved with modifications to existing technology.

<u>Adoption Rate Basis – Refineries (Fuel Switching)</u>

Technology:

Table 33: Refineries Adoption Rates - Technology

	2025 – 2030	2030 - 2040	2040+
Boilers	Low	Medium	High
Direct Process Heat	Medium	High	High
Direct Non-Process Heat	Medium	High	High

Rationale:

For boilers, burner development is in progression. There are still technological challenges that the industry is working through, namely: high volume hydrogen storage and piping, refractory and tube materials, flame management, and modification to safety solutions. The progression of technology reflects that commercial solutions appear in the medium term, with widespread availability after 2040.

For the other heating use cases, fired heating technology for high hydrogen based technology is in development and widespread commercial availability is expected by 2030.

Alternatives:

Table 34: Refineries Adoption Rates - Alternatives

	2025 – 2030	2030 - 2040	2040+
Boilers	High	Medium	Medium
Direct Process Heat	Medium	Low	Low
Direct Non-Process Heat	Medium	Low	Low

Rationale:

There is very low potential for electrification of boilers in this sub-sector given the steam mass flow requirements. However, while carbon capture will not be meaningful alternatives for relatively low CO2 emitting boilers, it is expected to be a more likely preferred alternative to direct process heating. This is because CCUS is projected to be a more mature technology in the medium term compared to hydrogen and more widely proven.

Commercial Availability:

Table 35: Refineries Adoption Rates – Commercial Availability

	2025 – 2030	2030 - 2040	2040+
Boilers	Low	Medium	Medium
Direct Process Heat	Low	Medium	Medium
Direct Non-Process Heat	Low	Medium	Medium

Rationale:

In the near term, there would be significant capital investments and performance penalties involved in the adoption for hydrogen for fuel switching. Heater and fuel gas system modifications will be very costly and hard to justify versus other decarbonization alternatives. However, as time progresses, innovative technology and a better understanding of the retrofit processes needed will increase the attractiveness of hydrogen-based technology. Further, an increased number of fired heaters are expected to reach end of life in the 2030+ timeframe and high efficiency hydrogen-based technology can serve as an alternative to rebuilding old units.

Adoption Rate Basis – Secondary Sub- Sectors (Paper, Chemical, Aerospace and Defense)

Technology:

Table 36: Secondary Subsectors Adoption Rates - Technology

	2025 – 2030	2030 - 2040	2040+
Boilers	**Low**	**Medium**	**High**
Direct Process Heat	**Low**	**Medium**	**High**
Direct Non-Process Heat	**Medium**	**High**	**High**

Rationale:

For boilers, burner development is in progression. There are still technological challenges that the industry is working through, namely: high volume hydrogen storage and piping, refractory and tube materials, flame management, and modification to safety solutions. The progression of technology reflects that commercial solutions appear in the medium term, with widespread availability after 2040.

There are expected to be less direct process heat applications specific to the secondary sub-sectors but innovations in furnace type technology in other primary sectors could be applied to similar equipment in these sectors.

Direct non-process heat is expected to reach similar levels of technology majority across similar manufacturing sub-sectors (e.g., food and beverage, metals)

Alternatives:

Table 37: Secondary Subsectors Adoption Rates - Alternatives

	2025 – 2030	2030 - 2040	2040+
Boilers	**Low**	**Low**	**Low**
Direct Process Heat	**Medium**	**Medium**	**Medium**
Direct Non-Process Heat	**Low**	**Low**	**Low**

Rationale:

Similar to other manufacturing operations (e.g., food and beverage, metals), there will be significant opportunities to electrify lower temperature equipment such as boilers and direct non-process heat. However, direct process heat will be hard to electrify and given the total emissions output from these facilities, there will be relatively less viability for carbon capture.

Commercial Availability:

Table 38: Secondary Subsectors Adoption Rates - Commercial Availability

	2025 – 2030	2030 - 2040	2040+
Boilers	**Low**	**Low**	**Low**
Direct Process Heat	**Low**	**Low**	**Low**
Direct Non-Process Heat	**Low**	**Low**	**Low**

Rationale:

Given these sectors have relatively low usage of natural gas compared to other primary sectors, there is low incentive for businesses to make significant investments in installing more expensive hydrogen-based technologies and conduct retrofits.

The primary opportunities for businesses to integrate hydrogen will be low levels of hydrogen blending to demonstrate commitments to ESG goals.

Fuel Switching - Cogeneration

The adoption rate methodology for hydrogen use in cogeneration will follow the same methodology and same results that was used to determine the adoption rates for power plants, detailed above in the Power section.

Refineries

Adoption rate assumptions were formed using SME input and analysis of refineries within the Southern California region, and then were validated with industry interviews. A set number of adoption milestones were identified as part of these assumptions and then annual adoption rates were scaled linearly between these dates.

First, it should be noted that approximately 40% of hydrogen is produced on-site, either through steam methane reformed (SMR) based hydrogen or as a byproduct of the petroleum refining process, and the remaining 60% is procured through outside vendors. The adoption milestones are the following:

2025: 0% of grey hydrogen can be transitioned to clean renewable hydrogen

2030: 50% of merchant hydrogen, hydrogen procured commercially, can be transitioned from grey hydrogen to clean renewable hydrogen. This results in 30% of total refinery demand being satisfied by clean renewable hydrogen.

2040: 100% of merchant hydrogen, can be transitioned from grey hydrogen to clean renewable hydrogen. This results in 60% of total refinery demand being satisfied by clean renewable hydrogen.

2045: 100% of merchant hydrogen and 25% on-site produced hydrogen can be transitioned from grey hydrogen to clean renewable hydrogen. This results in 70% of total refinery demand being satisfied by clean renewable hydrogen.

These assumptions are conditional that clean renewable hydrogen supply is readily available and at cost parity with grey hydrogen.

APPENDIX B: Locational Analysis

Angeles Link Phase 1 Demand Study

Appendix B: Locational Analysis

Mobility

Methodology

The mobility sector differs from Power and Industrials in that there are not specific facilities to model from, and so zip code level data was approximated. The model's core underlying data set, the CARB EMFAC Emissions Database,[84] contains data on vehicle type fuel consumption, by vehicle type, at a county level. So, this county-level data was used and allocated across current gasoline and/or diesel fueling stations by zip code. Since hydrogen refueling—and therefore hydrogen demand—is expected to generally happen at fueling stations, and since hydrogen fueling patterns are expected to largely reflect current gasoline and diesel (namely, diesel) fueling patterns, the locations of existing fueling locations was assumed to be a representative estimate of where future hydrogen fueling demand may be located. Current fueling station locations by type were identified using California Energy Commission data.[85]

On-Road

The locational analysis model takes the following approach to allocating on-road vehicle application demand by zip code:

1. Necessary data is collected:
    a. The CARB EMFAC Emissions Database[86] provides # of gallons of diesel and gasoline sales by county, by vehicle type. Note: 2019 data was used as a pre-covid benchmark for allocations.
    b. California Energy Commission data[87] provides the location (zip code) of all truck stops, hypermarts, cardlock facilities, and gas stations in SoCalGas service territory.
    c. Google Maps provides the location (zip code) of transit bus depots in the SoCalGas service territory.
2. Necessary data is used to determine what the percent of truck stops, gas stations, hypermarts, cardlock facilities and transit bus depots are in each zip

[84] https://arb.ca.gov/emfac/emissions-inventory/
[85] https://hub.arcgis.com/datasets/CalEMA::ca-energy-commission-gas-stations/explore
[86] https://arb.ca.gov/emfac/emissions-inventory/
[87] https://hub.arcgis.com/datasets/CalEMA::ca-energy-commission-gas-stations/explore

code. For example, there are 3 truck stops in Imperial County: 2 (67%) in 92243, 1 in 92275 (33%).

3. Assumptions are made for how much gasoline and/or diesel are sold at each fueling station by type. See below for more detail.
    a. Note: the amount of fuel sold at each location is not readily available public information, otherwise this information would have been used to allocate hydrogen demand across fueling station locations. Instead, each fueling station was assumed to be the same size (based on the type of station and type of fuel it sells).
4. For each vehicle type, the amount of diesel and/or gasoline sold in each county is multiplied by the values from percent of fueling stations (and therefore, percent of fuel) in each zip code to determine how much diesel and/or gasoline sales to allocate to each zip code within a specific county.
5. The values of percent diesel and/or gasoline sales by vehicle application and by zip code are multiplied by outputs from the hydrogen demand model to approximate hydrogen demand by zip code, by vehicle application. The percent allocation is assumed to be constant from 2025 to 2045.

Off-Road

The model takes the following approach to allocating off-road vehicle application demand by zip code:

1. Necessary data is collected:
    - The CARB EMFAC Emissions Database[88] provides the number of gallons of diesel and gasoline sales by county, by vehicle type.
    - California Energy Commission data[89] provides the location (zip code) of all truck stops, hypermarts, cardlock facilities, and gas stations in California (and in SoCalGas service territory).
    - The California Legislative Analyst's Office[90] provides the location (zip code) of all ports in California (and in SoCalGas service territory) in addition to the proportional volume of port activity.
    - The Bureau of Transportation Statistics[91] provides the location (zip code) of all airports in California (and in SoCalGas service territory) in addition to the proportional volume of airport activity.

[88] https://arb.ca.gov/emfac/emissions-inventory/
[89] https://hub.arcgis.com/datasets/CalEMA::ca-energy-commission-gas-stations/explore
[90] https://lao.ca.gov/Publications/Report/4618
[91] https://www.transtats.bts.gov/Data_Elements.aspx?Data=1

2. Necessary data is used to determine the percent of truck stops, cardlock facilities, airports and ports are in each zip code.
3. Assumptions are made to reflect which types of vehicles refuel at each location:
    - GSE and Aircraft refuel at Airports.
    - CHC, OGV and CHE refuel at the Ports.
    - Agricultural equipment refuels at (or receive from) Truck Stops
    - Construction & Mining equipment refuels at Cardlock Facilities
4. For each vehicle type, the number of gallons of diesel sold in a county is multiplied by the percent of associated fueling stations associated with each vehicle type to determine how much diesel sales to allocate to each zip code within a specific county.
5. The values of percent diesel sales by vehicle application and by zip code are multiplied by outputs from the hydrogen demand model to approximate hydrogen demand by zip code, by vehicle application. The percent allocation is assumed to be constant from 2025 to 2045.

Assumptions

The allocation of mobility application hydrogen demand by zip code is contingent on a few key assumptions:

- **That all fuelling locations by type (e.g., Truck Stops) sell the same amount of fuel as other fuelling locations of the same type in a given county.** The amount of fuel sold at each location is not readily available public information, otherwise this information would have been used to allocate hydrogen demand across fueling station locations.
- **That current consumption patterns by fuel types will remain constant.** I.e. that current diesel and/or gasoline fuelling patterns are representative of future hydrogen demand fuelling patterns by vehicle application.
- **That vehicle applications refuel at the following types of fueling stations:**

Table 39: Mapping of Fueling Station Type to Vehicle Categories

Vehicle Application	Fueling Locations
LDV	Service Station or Gas Station, Hypermart, Cardlock Facility,
MDV	Service Station or Gas Station, Hypermart, Cardlock Facility, Truck Stops
HDV	Truck Stops
Transit Bus	Transit Bus Depots
CHE	POLA, POLB
GSE	Airports
Agricultural	Truck Stop
C&M	Cardlock Facility
CHC	Ports
OGV	POLA, POLB
Aviation	Airports

- **That diesel and/or gasoline vehicles, by refueling mode, refuel at the various fueling station types according to the following schedules**. For example, that Drayage Trucks fall under "Back to base" operations and refuel 100% at cardlock facilities:

Table 40: Allocations of fueling station type for diesel applications

Fueling category	Service Station or Gas Station	Hypermart	Cardlock Facility	Truck Stop	Bus Depot
HDV	0%	0%	0%	100%	0%
Back to base	0%	0%	100%	0%	0%
MDV	30%	0%	0%	70%	0%
Gasoline applications	0%	0%	0%	0%	0%
Transit bus	0%	0%	0%	0%	100%

Table 41: Allocations of fueling station type for gasoline applications

Fueling category	Service Station or Gas Station	Hypermart	Cardlock Facility	Truck Stop	Bus Depot
HDV	0%	0%	0%	0%	0%
Fleets	0%	0%	0%	0%	0%
Other	0%	0%	0%	0%	0%
Gasoline applications	95%	3%	1%	1%	0%
Transit bus	0%	0%	0%	0%	0%

- That SoCalGas service area **reflects the zip codes found in the 11 counties: Imperial, Kern, Kings, Los Angeles, Orange, Riverside, San Bernardino, San Luis Obispo, Santa Barbara, Tulare, Ventura.** Around 30 zip codes fall outside of these counties, so their potential demand is allocated to the zip codes within the defined nearest counties. This assumption does not materially impact the findings of the model which contains 739 zip codes. Since EMFAC fuel consumption data is only available at the county level, the demand for zip codes outside of these counties is not modelled.

Power

Locational demand in the power sector has been estimated based on proportion of current plant natural gas combustion compared to total locational area. Therefore, all plants show some level of hydrogen adoption in the locational analysis. This method was chosen in order to remain agnostic about which power plants will choose to move to hydrogen versus alternatives and is intended to be used to identify potential hotspots of demand rather than to quantify the exact level of demand for each individual zip code.

Limitations of this approach are noted below:

- This method assumes all plants adopt hydrogen at some midpoint percentage between 0 and 100%. In reality, it is likely that some plants will not move to hydrogen, and some plants will move their operations fully to hydrogen as hydrogen turbines become available. The model will overcount and undercount hydrogen demand, respectively. Continued tracking of power plant commitments will help to understand which areas of the locational model may be underestimated and which may be overestimated.

- Given the uneven locational distribution of zip codes, some zip code projections will only include one power plant while some zip codes will include multiple. This may cause large fluctuations between the projection and reality for zip codes with a smaller number of power plants.

Industrials

In order to determine the zip code granularity of the location of hydrogen demand for a particular sub-sector, demand is first determined at a facility level of granularity. The total demand for hydrogen, per annum, is multiplied by the percent of natural gas that facility contributed to the total natural gas consumption in that particular sub-sector. The demand figure represents the probabilistic expected value of demand for that facility. Once the facility – level data has been estimated, it is rolled up to the zip level of granularity.

APPENDIX C: List of H2 Projects

Angeles Link Phase 1 Demand Study

Appendix C: List of H2 Projects

Mobility

There has been an increase in recent years of clean hydrogen powered vehicle development initiatives, announced vehicle launches from OEMs (original equipment manufacturers, e.g., the auto manufacturers) and announced hydrogen fueling stations from fueling station operators and by the California Energy Commission. These announcements and proposed projects point to the increasing interest by the mobility sector for hydrogen-fueled alternatives to conventional vehicles. Several key announced projects in California and across the U.S. are outlined below:

Table 42: Select Public OEM Hydrogen Vehicle Announcements in the Mobility Sector

Company	Sub-Sector	Type	Hydrogen Potential
Toyota	On-Road HDV	OEM	Toyota and Kenworth successfully complete ZANZEFF Project demonstrating the operation of their Toyota-Kenworth T680 FCEV truck at the Port of Los Angeles.[92]
Hyundai	On-Road	OEM	Hyundai's XCIENT fuel cell truck makes its commercial debut in the U.S. in the summer of 2023, with a range of 450 miles when fully loaded.[93]
Cummins Scania	On-Road	OEM	Cummins provides PEM fuel cell systems to Scania to develop 20 FCEVs in 2024.[94]
Nikola Corporation	On-Road	OEM	Nikola CEO states that their gamma hydrogen fuel cell electric trucks are achieving more than 900 miles of range in a day.[95]
Hyzon	On-Road	OEM	Hyzon manufactures commercial hydrogen-powered fuel-cell vehicles for customers

[92] https://pressroom.toyota.com/toyota-kenworth-prove-fuel-cell-electric-truck-capabilities-with-successful-completion-of-truck-operations-for-zanzeff-project/
[93] https://www.ccjdigital.com/alternative-power/hydrogen-fuel-cell/video/15543046/hyundais-xcient-fuel-cell-truck-makes-its-commercial-debut
[94] https://www.cummins.com/news/2022/04/28/cummins-fuel-cells-power-scanias-fuel-cell-electric-trucks
[95] https://www.sec.gov/Archives/edgar/data/1731289/000173128923000252/exhibit991firesidechat91323.htm

			globally. The heavy-duty trucks they have on the road today are the HYHD8-200, they Hymax series, the Refuse, and the HYHD8-110.[96]
Daimler Truck	On-Road	OEM	In 2020, Daimler Truck present the Mercedes-Benz GenH2 Truck powered by a hydrogen fuel cell. On September 26, 2023, the prototype heavy-duty GenH2 Truck covered 1,047 km of distance on one fill of liquid hydrogen.[97]
John Deere	Off-Road	OEM	John Deere presented plans in 2021 to the DOE for hydrogen fueled farming equipment.[98]
CNHi	Off-Road	OEM	CNHi presented plans in 2021 to the DOE for hydrogen fueled farming equipment.[99]
John Deere	Off-Road	OEM	AGCO presented plans in 2021 to the DOE for hydrogen fueled farming equipment.[100]
Komatsu	Off-Road	OEM	Komatsu presented plans in 2021 to the DOE for hydrogen fueled construction and mining equipment.[101], [102]
Toyota	Off-Road	OEM	Toyota offers hydrogen fuel cell forklifts.[103]
Hyster	Off-Road	OEM	Hyster offers hydrogen fuel cell forklifts.[104]
STILL	Off-Road	OEM	STILL offers a portfolio of trucks with hydrogen fuel cell systems, such as to tractors, high lift

[96] https://www.hyzonmotors.com/vehicles
[97] https://www.daimlertruck.com/en/newsroom/pressrelease/fuel-cell-technology-daimler-truck-builds-first-mercedes-benz-genh2-truck-customer-trial-fleet-52552943
[98] https://www.energy.gov/sites/default/files/2021-12/922-10-mission-innovation-JD.pdf
[99] https://www.energy.gov/sites/default/files/2021-12/922-11-mission-innovation-CNH.pdf
[100] https://www.energy.gov/sites/default/files/2021-12/922-12-mission-innovation-AGCO.pdf
[101] https://www.energy.gov/sites/default/files/2021-12/923-2-mission-innovation-komatsu.pdf
[102] https://www.energy.gov/sites/default/files/2021-12/923-4-mission-innovation-komatsu.pdf
[103] https://www.toyotaforklift.com/resource-library/blog/energy-solutions/hydrogen-fuel-cell-forklifts-an-alternative-energy-solution
[104] https://www.hyster.com/en-us/north-america/technology/power-sources/hydrogen-fuel-cells/

			pallet trucks, reach trucks and counterbalanced forklift trucks.[105]
Linde	Off-Road	OEM	Linde offers hydrogen fuel cell forklifts.[106]
First Mode	Off-Road	OEM	In May of 2022, First Mode debuted it's proof-of-concept and the world's first and largest hydrogen-fueled mining haul truck. In 2023, the hydrogen-fueled haul truck successfully completed one full year of operational trials.
Stadler	Rail	OEM	In 2023, Stadler delivered the first hydrogen powered train for American transport—the FLIRT H2. The train is equipped with a power pack that uses modular fuel cells and batteries
Airbus	Aviation	OEM	Airbus in 2020 announced ZEROe, their plan to produce hydrogen combustion and fuel cell commercial aircraft by 2035.[107]

Table 43: Select Public Hydrogen Pilot Project / Demonstration Announcements in the Mobility Sector

Company	Sub-Sector	Type	Hydrogen Potential
AJR Trucking[108]	On-Road	Hydrogen Pilot Project / Demonstration	AJR Trucking, a leading carrier for the US Postal Service, announced the execution of a purchase order of 50 Nikola Tre trucks in May 2023.
Sunline Transit.[109]	On-Road	Hydrogen Pilot Project / Demonstration	Sunline transit operate multiple fuel cell buses, the Flyer XHE40, in its fleet and has dedicated fueling stations to refuel each

[105] https://www.still.co.uk/solution-competence/energy-systems/fuel-cell-technology.html
[106] https://www.linde-mh.com/en/About-us/Innovations-from-Linde/Fuel-Cells.html
[107] Airbus. "ZEROe". (2023) https://www.airbus.com/en/innovation/low-carbon-aviation/hydrogen/zeroe
[108] https://www.ajrtrucking.com/blog/ajr-trucking-announces-order-for-50-nikola-tre-fcevs/#:~:text=COMPTON%2C%20CA%20%E2%80%93%20May%201%2C,FCEV%E2%80%9D)%20trucks%20from%20Tom's%20Truck
[109] https://ww2.arb.ca.gov/lcti-sunline-fuel-cell-buses-hydrogen-onsite-generation-refueling-station-pilot-commercial

Foothill Transit[110]	On-Road	Hydrogen Pilot Project / Demonstration	Foothill Transit operates 33 hydrogen fuel cell buses, the Xcelsior CHARGE H2, and has 19 more on order.
AC Transit[111]	On-Road	Hydrogen Pilot Project / Demonstration	AC Transit operates 36 hydrogen fuel cell buses in its fleet.
Orange County Transit Authority (OCTA)[112]	On-Road	Hydrogen Pilot Project / Demonstration	OCTA operates 10 hydrogen fuel cell buses in its fleet.
Switch Maritime[113]	Commercial Harbor Craft	Hydrogen Pilot Project / Demonstration	The first hydrogen fuel-cell powered 75-passenger commercial ferry is piloted to serve ports in the San Francisco Bay area starting in spring 2023.
ZeroAvia[114]	Aircraft	Hydrogen Pilot Project / Demonstration	ZeroAvia has partnered with Alaska Airlines and in mid-2023 flew a converted Bombardier Q400 aircraft powered by hydrogen fuel cells.
Universal Hydrogen[115]	Aircraft	Hydrogen Pilot Project / Demonstration	Universal Hydrogen in early 2023 flew a converted De Havilland Canada Dash 8 aircraft powered by hydrogen fuel cells.
Santa Cruz Hydrogen Fuel Cell (HFC) [116]	Rail	Hydrogen Pilot Project / Demonstration	In Northern California, the Santa Cruz Hydrogen Fuel Cell (HFC) Streetcar project, launched in 2021, represents a pioneering move towards Electric Passenger Rail in the coastal rail corridor.

110 https://www.foothilltransit.org/greeningbig
111 https://www.actransit.org/zeb
112 https://www.octa.net/about/about-octa/environmental-sustainability/fuel-cell/
113 https://ww2.arb.ca.gov/lcti-zero-emission-hydrogen-ferry-demonstration-project
114 ZeroAvia. (2023). https://zeroavia.com/
115 Universal Aviation. (2023). https://www.universalaviation.aero/
116 Memorandum of Understanding between BNSF, Progress Rail, and Chevron https://www.progressrail.com/en/Company/News/PressReleases/CaterpillarBNSFandChevronAgreetoPursueHydrogenLocomotiveDemonstration.html

GTI and Sierra Northern[117]	Rail	Hydrogen Pilot Project / Demonstration	The California Energy Commission awarded GTI and Sierra Northern $4 million to fund the design, integration, and demonstration of a hydrogen fuel cell switching locomotive to support the (H2RAM) initiative.
California Energy Commission (CEC)[118]	On-Road	Hydrogen Pilot Project / Demonstration	The CEC is investing in a network of 100 public hydrogen fueling stations across California, through $27 million of grant funding as part of the Clean Transportation Program.
FirstElement Fuel, Inc.[119]	On-Road	Hydrogen Pilot Project / Demonstration	FirstElement Fuel partners with Hyundai Motor on hydrogen refueling of class 8 fuel cell electric trucks.
Iwatani, Chevron[120]	On-Road	H2 Infrastructure Deployment	Co-developing and operating 30 hydrogen fueling sites in California by 2026, located at existing Chevron-branded retail locations.
Santa Cruz Metropolitan Transport[121]	On-Road	H2 Pilot Project / Demonstration	Santa Cruz Metropolitan Transport District procuring 57 hydrogen-powered, fuel cell buses.

117 https://www.gti.energy/california-energy-commission-awards-funding-to-demonstrate-hydrogen-locomotive-for-rail-applications-in-california/
118 https://www.energy.ca.gov/programs-and-topics/programs/clean-transportation-program
119 https://www.prnewswire.com/news-releases/firstelement-fuel-partners-with-hyundai-motor-on-hydrogen-refueling-of-class-8-fuel-cell-electric-trucks-driving-over-25k-miles-with-zero-emissions-301770655.html
120 https://www.chevron.com/newsroom/2022/q1/chevron-iwatani-announce-agreement-to-build-30-hydrogen-fueling-stations-in-california
121 https://scmtd.com/images/department//ceo/METRO_HydrogenBusPurchase_Release092223FINAL.pdf

Power

Table 44: Select Public Hydrogen Pilot Project / Demonstration Announcements in the Power Sector

Companies Involved / Project Name	Type	Hydrogen Potential
LADWP Scattergood Repowering Project[122]	Hydrogen turbine upgrade	LADWP is repowering their Scattergood plant with turbines capable of burning significant quantities of hydrogen, with ~400MW of H2 capacity buildout at Scattergood by 2038 • **400MW** Net generation output by 2038
Intermountain Power Project[123]	Hydrogen turbine upgrade	Project is retiring the existing coal-fueled units at the Utah IPP site, installing new natural gas-fueled electricity generating units capable of utilizing hydrogen. • **840MW** Net generation output
PG&E Lodi Hydrogen Power Plant[124]	Hydrogen turbine upgrade	PG&E has successfully installed a Siemens turbine at the Lodi Energy Center that can blend 45% hydrogen with natural gas, greatly reducing emissions. • **225MW** Net generation output as of 2022

[122] Los Angeles moves forward with $800m plan to convert 830MW gas-fired power plant to run on green hydrogen https://www.hydrogeninsight.com/power/los-angeles-moves-forward-with-800m-plan-to-convert-830mw-gas-fired-power-plant-to-run-on-green-hydrogen/2-1-1401866
[123] https://www.ipautah.com/ipp-renewed/
[124] Lodi to be base for hydrogen pilot program providing power to NorCal | News | lodinews.com https://www.lodinews.com/news/article_a18bc96e-e788-11ec-80fa-7730df49a97e.html

Constellation Hillabee Generating Station[125]	Hydrogen blending	Constellation will significantly lower greenhouse gas emissions by blending high concentrations of hydrogen with natural gas, reaching 38% without major modifications to the plant. • **753MW** Net generation output as of 2023
NextEra Energy Blueprint for Real Zero Proposal[126]	Hydrogen turbine upgrade	NextEra Energy envisions converting all of its Florida natural gas firing facilities to hydrogen. Collectively these plants will produce 16GW from green hydrogen. • **16GW** Net generation output by 2040
Equinor & RWE Low Carbon Energy Hub[127]	Hydrogen turbine upgrade & hydrogen pipeline	RWE and Equinor are building gas turbines in Germany served by a hydrogen pipeline between Germany and Norway, moving ~4M tonnes hydrogen/year with a target of 2030 for pipeline construction. • **3GW** H2 power plant capacity, with a pipeline equivalent capacity of 18GW
Siemens[128]	OEM Hydrogen Capability Upgrades	• In 2019, Siemens Gas and Power announced a roadmap to ramp up the hydrogen capability in its gas turbine models to at least 20% by 2020, and 100% by 2030. • Siemens has demonstrated over 38% by volume hydrogen on a G class machine.
General Electric[129]	OEM Hydrogen	• GE is aiming to develop a 100% hydrogen turbine by 2030.

[125] https://www.utilitydive.com/news/constellation-energy-hydrogen-blending-test-hillabee-power-plant/652000/
[126] https://www.nexteraenergy.com/home.html
[127] Equinor and German energy major RWE to cooperate on energy security and decarbonization - Equinor
[128] https://www.powermag.com/siemens-roadmap-to-100-hydrogen-gas-turbines/
[129] https://www.gevernova.com/gas-power/future-of-energy/hydrogen-fueled-gas-turbines

	Capability Upgrades	• GE was awarded $6.6M from DOE to test retrofitting F-class turbines with hydrogen blends. • GE turbines have logged more than 8 million operating hours using blends of hydrogen by over 100 customers in 20 countries. • It is operating a demonstration project to temporarily replace natural gas with a green hydrogen / natural gas blend in NY. • GE has ongoing programs to develop 100% hydrogen capable turbines on E, F and H class turbines
Mitsubishi[130]	OEM Hydrogen Capability Upgrades	• In 2018, Mitsubishi developed a gas turbine that runs on 30% hydrogen and 70% natural gas. Its goal is to develop a turbine that is 100% powered by hydrogen by 2025. • Mitsubishi has demonstrated over 20% by volume hydrogen on a G class machine.

Industrials

Table 45: Select Public Hydrogen Pilot Project / Demonstration Announcements in the Industrials Sector

Companies Involved	Sub-Sector	Hydrogen Potential
AMF Den Boer	Food & Beverage	The Multibake® VITA Tunnel Oven is a direct-fired oven with patent-pending hydrogen-fueled burners that use green energy or hydrogen as its renewable resource.

[130] https://solutions.mhi.com/clean-fuels/hydrogen-gas-turbine/

Mountaintop Beverage West Virginia University (WVU)	Food & Beverage	WVU is developing a hydrogen flexible boiler with DOE grant funding. Mountaintop Beverage will provide access to its facility for sampling data, quality analyses, and to provide industry input.
FLSmidth	Cement	Offers green hydrogen burner kiln for mineral processing that enables up to 100% hydrogen burning, and pilot plant for potential clients to test whether/how to operate with hydrogen.
Cemex	Cement	CEMEX will implement hydrogen injection technology at four of its cement plants in Mexico as part of its Future in Action program.
Cemex, Sandia Labs, and Synhelion	Cement	Field demonstration of fuels production using green H2, CO2 from cement, and high temperature process heat from the sun.
Linde Gas AB and its partner, Ovako	Metals	Steel was heated in pit furnace using 100% hydrogen instead of LPG (liquefied petroleum gas) before rolling; deemed equivalent in character.
Tenova and Tenaris	Metals	A 200-kW burner optimized for high efficiency in steel reheating furnaces; runs with minimum NOx.
Linden Cogeneration and Phillips 66	Industrial Cogeneration	Linden Cogeneration is utilizing Phillips 66 produced refinery off gas containing blending it with natural gas in its cogeneration plant in Linden, New Jersey