ANGELES LINK PHASE 1

HIGH-LEVEL ECONOMIC ANALYSIS & COST EFFECTIVENESS

FINAL REPORT – DECEMBER 2024

SoCalGas commissioned this High-Level Economic Analysis & Cost Effectiveness from Wood Mackenzie. The analysis was conducted, and this report was prepared, collaboratively.

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0. Acronyms, Glossary, Tables & Figures

0.1. Acronyms and Abbreviations

ALMA	Angeles Link Memorandum Account
ARCHES	Alliance for Renewable Clean Hydrogen Energy Systems
BOP	Balance of Plant
BEV	Battery Electric Vehicle
B2B	Back to base
CARB	California Air Resources Board
CBOSG	Community-Based Organizations Stakeholder Group
CapEx	Capital Expenditure
CCS	Carbon Capture and Storage
CEC	California Energy Commission
CHP	Combined Heat and Power
CPUC	California Public Utilities Commission
CO_2	Carbon Dioxide
DOE	Department of Energy
DTS	Depreciation Tax Shield
DOGR	Depleted Oil & Gas Reservoir
EPA	Environmental Protection Agency
GHG	Greenhouse Gas
F&B	Food & Beverage
FCEB	Fuel Cell Electric Bus
FCEV	Fuel Cell Electric Vehicle
HDV	Heavy-Duty Vehicle
HVDC	High Voltage Direct Current
H_2	Hydrogen
IRR	Internal Rate of Return
ITC	Investment Tax Credit
Kg	Kilogram
LCOH	Levelized Cost of Delivered Hydrogen
LDES	Long duration energy storage
LDV	Light Duty Vehicle
MDV	Medium Duty Vehicle
mi	Mile
MGD	Million gallons per day
MM	Million
$MMBtu_e$	Million Metric British Thermal Units equivalent
MTPA	Million tonnes per annum
MWh	Mega-watt hour
NPC	National Petroleum Council
NPV	Net Present Value
OEM	Original Equipment Manufacturer
O&M	Operations and Maintenance
OTR	On the road
OpEx	Operating Expenses
PAG	Planning Advisory Group
PTC	Production Tax Credit
REC	Renewable Electricity Certificate
RNG	Renewable Natural Gas
SJV	San Joaquin Valley
SMR	Steam methane reformer
SoCalGas	Southern California Gas Company
T&D	Transmission and Distribution
T-Bond	Treasury Bond
TCO	Total Cost of Ownership
UGSC	Underground Geologic Salt Caverns
VRFB	Vanadium Redox Flow Batteries
ZEV	Zero Emission Vehicle
T&S	Transport and Sequestration

LA	Los Angeles
LCFS	Low Carbon Fuel Standards
LCOE	Levelized Cost of Electricity

0.2. Glossary of Terms

The following terms are used in this report. For the purposes of this report, the terms are used as follows:

Carbon capture and storage (CCS) – A set of technologies that remove CO_2 either from the atmosphere or from point sources. The captured CO_2 is then compressed and injected into deep underground geological formations (that may include depleted oil and gas reservoirs or saline formations) for permanent storage.[1] For purposes of this report, CCS alternatives are those that include the removal of CO_2 from point sources and permanent sequestration (not for use in oil and gas recovery).

Clean firm power - Zero-carbon power generation sources that can be relied on whenever and for as long as needed. Clean firm power sources do not depend on the weather like solar and wind do, and do not have limitations in duration of power production capabilities (as long as fuel is available).[2]

Clean renewable hydrogen – For purposes of Angeles Link Phase 1 studies, clean renewable hydrogen refers to hydrogen that is produced through a process that results in a lifecycle (i.e., well-to-gate) greenhouse gas (GHG) emissions rate of not greater than four kilograms of carbon dioxide-equivalent per kilogram of hydrogen produced and does not use any fossil fuel in its production process.[3]

Cogeneration – Combined heat and power (CHP), also referred to as cogeneration, is the simultaneous generation of useful heat and electricity from a single fuel source.[4]

Dispatchable energy/dispatchable generation – Resources that are classified as dispatchable by the scheduling coordinator (SC) or the California Independent System Operator (CAISO) and could include a variety of technologies: steam turbines; combustion turbines; combined cycle gas turbines; reciprocating engines; energy storage; dispatchable CHP; biomass and geothermal resources.[5]

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[1] https://www.congress.gov/bill/117th-congress/senate-bill/799/text

[2] https://www.edf.org/sites/default/files/documents/SB100%20clean%20firm%20power%20report%20plus%20SI.pdf , p. 5.

[3] As defined in CPUC Decision (D.) 22-12-055.

[4] CPUC Combined Heat and Power (CHP) https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/combined-heat-and-power-program-overview

[5] CPUC https://www.cpuc.ca.gov/-/media/cpuc-website/files/legacyfiles/q/6442466773-qc-manual-2020.pdf

Electrification – Electrification refers to a combination of system level[6] transformation and use case level[7] technology changes including the grid infrastructure required to support growing electric load. The purpose of electrification in California is to reduce GHG emissions in carbon-intensive demand sectors by powering these sectors with electricity produced using zero carbon technologies over time.[8]

Electrolyzer – Electrolysis is the process of using electricity to split water into hydrogen and oxygen. This reaction takes place in a unit called an electrolyzer.[9]

Energy density – The amount of energy that can be stored per unit of volume or mass; higher energy density means more energy can be stored in a smaller volume or mass.[10]

***Levelized Cost of Electricity* (*LCOE*) –** Represents the average revenue per unit of electricity generated that would be required to recover the return on capital related to costs of building and operating a generating plant. LCOE is a summary metric to measure of the overall competitiveness of different generating technologies.[11]

Linepack – Gas linepack refers to the gas stored in gas pipelines due to the compressibility of the gas. As a form of gas energy storage, linepack can enhance system flexibility.[12]

Long-duration energy storage (LDES) – A portfolio of technologies that store energy over long periods for future dispatch and marked by duration of dispatch (e.g., multi-day and seasonal).[13]

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[6] System level electrification includes the incremental electricity generation, storage, and supporting upstream grid infrastructure requirements to meet wide-scale end use electrification needs.

[7] Use-case level electrification refers to replacing technologies or processes that use fossil fuels, like internal combustion engines and gas boilers, with electrically powered equivalents, such as electric vehicles or heat pumps. More detail at https://www.iea.org/energy-system/electricity/electrification

[8] California Air Resources Board, https://ww2.arb.ca.gov/our-work/programs/ab-32-climate-change-scoping-plan/2022-scoping-plan-documents

[9] https://www.energy.gov/eere/fuelcells/hydrogen-production-electrolysis, DOE Office of Energy Efficiency & Renewable Energy.

[10] Department of Energy Vehicle Technology Office definition, available at https://www.energy.gov/eere/vehicles/articles/fotw-1234-april-18-2022-volumetric-energy-density-lithium-ion-batteries

[11] As defined in EIA https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf

[12] As defined in https://www.sciencedirect.com/science/article/abs/pii/S2352152X2303116X Wu et al.

[13] DOE https://liftoff.energy.gov/long-duration-energy-storage/

Levelized Cost of Delivered Hydrogen (LCOH) – Reflects the unit cost of hydrogen based on the return on capital related to the cost of production, transmission, storage, and distribution. When used in this study, LCOH refers to the delivered cost of hydrogen.

Reliability and resiliency – Reliability refers to a system having sufficient resources to adequately meet demand while accounting for commonly-expected events (e.g. equipment failure, short-duration outages). Resilience focuses on the ability of a system to withstand/recover from high-impact, low-frequency events that are often unexpected and can result in long duration outages.[14]

Renewable energy – Renewable energy uses energy sources that are continually replenished by nature — the sun, the wind, water, the Earth's heat, and plants. Renewable energy technologies turn these fuels into usable forms of energy—most often electricity, but also heat, chemicals, or mechanical power.[15]

Renewable natural gas (RNG) – Also known as "biomethane," RNG is a combustible gas produced from the anaerobic decomposition of organic materials (i.e., biogas) that is captured and then purified to a quality suitable for injection into a gas pipeline. Major sources of biomethane include non-hazardous landfills, wastewater treatment facilities, organic waste, and animal manure. The California Public Utilities Commission (CPUC) has recognized that "Biomethane can capture methane emissions from the waste sector and be used as a direct replacement for fossil natural gas to help California reduce its GHG emissions."[16]

***Total cost of ownership* (TCO)** – For the transportation sector, a metric representing a lifetime dollar ($) per mile "comprehensive analysis of vehicle ownership costs."[17] TCO in this study includes initial purchase cost, maintenance and repairs, operations, fuel cost, and taxes and subsidies (further details in Appendix 7.1.3).

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[14] CPUC https://www.cpuc.ca.gov/-/media/cpuc-website/industries-and-topics/meeting-documents/vorlumen20230321resiliency-definitionsfinal.pdf

[15] Per NREL's https://www.nrel.gov/docs/fy01osti/27955.pdf report for the Department of Energy.

[16] More details on definition available at https://www.cpuc.ca.gov/industries-and-topics/natural-gas/renewable-gas

[17] Department of Energy report on https://publications.anl.gov/anlpubs/2021/05/167399.pdf, p. xvii.

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1. Executive Summary

1.1. High-Level Economic Analysis & Cost Effectiveness Study Overview

Southern California Gas Company (SoCalGas) proposes to develop a hydrogen[18] pipeline system (Angeles Link) to transport clean renewable hydrogen from regional third-party production sources and storage sites to end users in Central and Southern California, including in the Los Angeles Basin (L.A. Basin). The Angeles Link pipeline system is anticipated to extend across approximately 450 miles.

Angeles Link is intended to support California's decarbonization goals[19] through the significant reduction of greenhouse gas (GHG) emissions in hard-to-electrify sectors of the economy, including dispatchable power generation, mobility,[20] and industrial sectors. Additionally, Angeles Link seeks to enhance energy system reliability and resiliency, and to enable the development of third-party long duration energy storage (LDES) resources, as California works to achieve the State's decarbonization goals.

On December 15, 2022, the California Public Utilities Commission (CPUC) approved Decision (D.) 22-12-055, authorizing SoCalGas to establish the Angeles Link Memorandum Account (ALMA) to track expenses related to conducting Phase 1 feasibility studies.[21] This High-Level Economic Analysis & Cost Effectiveness Study (hereafter referred to as the Cost Effectiveness Study) is prepared pursuant to the Phase 1 Decision (D.22-12-055, Ordering Paragraph [OP] 6 (d)). Pursuant to OP 6(d), this study considers and evaluates project alternatives, including a localized hydrogen hub and electrification, determines a methodology to measure cost effectiveness between alternatives, and evaluates the cost effectiveness of Angeles Link against alternatives. This report sets forth the scope, methodology, and results of this study. Input and feedback from stakeholders including the Planning Advisory Group (PAG) and Community Based Organization Stakeholder Group (CBOSG) was helpful in the development of this Cost Effectiveness Study. In response to stakeholder feedback, the Cost Effectiveness Study has addressed various topics, including power transmission technologies and the cost effectiveness of hydrogen as a fuel in heavy-duty mobility applications. In addition, further details on costs and input assumptions have been added throughout this report and in the Appendix. Key feedback received related to the Cost Effectiveness Study is summarized in

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[18] As defined in the decision approving the https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M499/K891/499891989.PDF

[19] For example, see 2022 Scoping Plan Documents | California Air Resources Board and Senate Bill 100 (SB 100).

[20] https://www.gov.ca.gov/wp-content/uploads/2020/09/9.23.20-EO-N-79-20-Climate.pdf, also CARB's Advanced Clean Fleets and Truck regulations.

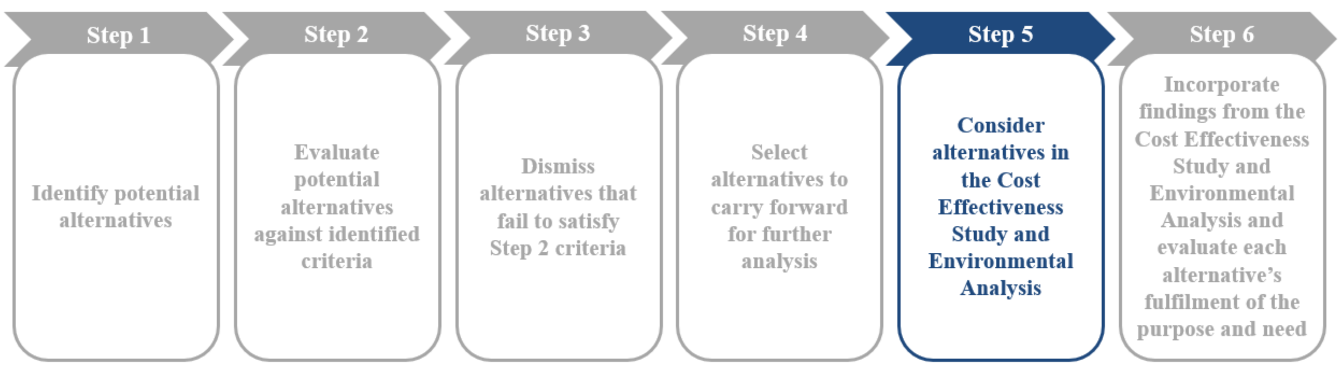
[21] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M499/K891/499891989.PDF

Section 5 below. All feedback received is included, in its original form, in the quarterly reports submitted to the CPUC and published on SoCalGas's website.[22]

1.2. Study Approach

The Cost Effectiveness Study was conducted in conjunction with the Project Options & Alternatives Study (Alternatives Study), which followed a six-step evaluation framework (see Figure 1) to identify alternatives to Angeles Link and assess them based on a range of factors. Steps 1-4 were completed in the Alternatives Study, which identified potential alternatives to Angeles Link and evaluated them against key considerations or criteria such as state policy goals, scalability, and reliability and resiliency, among others. Alternatives that met these criteria were then carried forward to Step 5 for cost effectiveness and environmental analysis. The Cost Effectiveness Study encompasses the methodology and analysis to measure the cost effectiveness of Angeles Link and alternatives for Phase 1 purposes. The Environmental Analysis, prepared as a separate Angeles Link Phase 1 report, contains a high-level analysis of potential environmental impacts of Angeles Link and its alternatives.

Figure 1: Cost Effectiveness Study's Role in Alternatives Study Evaluation Framework[23]



The Cost Effectiveness Study evaluation is organized according to two categories of alternatives, as described in the Alternatives Study: Hydrogen Delivery Alternatives and Non-Hydrogen Alternatives. For each category of alternatives, this study seeks to address the following questions:

[22] https://www.socalgas.com/sustainability/hydrogen/angeles-link

[23] See Alternatives Study for additional information on the six-step evaluation framework, including the alternatives considered but dismissed for evaluation in the Cost Effectiveness Study.

Hydrogen Delivery Alternatives: *How does the cost of Angeles Link compare to the cost of alternative methods for delivering clean renewable hydrogen to end users in the region across mobility, power, and industrial sectors?*

Non-Hydrogen Alternatives: *How does the cost of clean renewable hydrogen delivered via Angeles Link compare to the cost of alternative, non-hydrogen decarbonization pathways for key use cases across mobility, power, and industrial sectors?*

Table 1 below describes the alternatives selected in the Alternatives Study for further cost analysis in this Cost Effectiveness Study.

Table 1: Portfolio of Selected Alternatives for Cost Effectiveness Evaluation

Hydrogen Delivery Alternatives	Non-Hydrogen Alternatives
• Liquid hydrogen trucking • Gaseous hydrogen trucking • Liquid hydrogen shipping • Methanol shipping • Power transmission & distribution (T&D) with in-basin hydrogen production • Localized hub	• Electrification • Carbon Capture & Sequestration (CCS)

The evaluation of Hydrogen Delivery Alternatives focused on the estimated cost of transporting clean renewable hydrogen at scale via Angeles Link (including third-party production and storage), compared to the cost of producing, storing, and transporting clean renewable hydrogen via the delivery alternatives. The cost effectiveness of Angeles Link relative to other Hydrogen Delivery Alternatives is measured using the Levelized Cost of Delivered Hydrogen (LCOH, $/kg),[24] which is an accepted energy industry metric to evaluate cost-effectiveness across various hydrogen delivery technologies.
In addition to the Alternatives Study, the evaluation of Angeles Link took a number of inputs from several other Phase 1 feasibility studies including the Production Planning and Assessment (Production Study), the Demand Study, and the Routing/Configuration Analysis

[24] See Glossary of Terms for the definition of LCOH. The cost effectiveness study was not intended to address the retail (commodity) price of hydrogen. See Q1 2024 Angeles Link quarterly report for additional information. In addition, this study was not intended to provide a total cost for Angeles Link; please refer to the Design Study for a total investment cost.

(Routing Analysis).[25] These studies identified eight potential operational scenarios for the Angeles Link pipeline system, referred to as "Production Scenarios."[26] The identified Production Scenarios represent various potential routes and distances connecting potential third-party production and storage areas to demand sites as well as various throughput volumes.[27]

For purposes of the Cost Effectiveness Study, a single route configuration under Production Scenario 7[28] was selected as the primary basis to compare Angeles Link to the selected Hydrogen Delivery Alternatives. Scenario 7 was selected due to its alignment with the Alliance for Renewable Clean Hydrogen Energy Systems (ARCHES)[29] hub proposal and its ability to facilitate transportation of up to 1.5 million tons per year of hydrogen to meet expected demand.

The evaluation of Non-Hydrogen Alternatives focused on the estimated cost to end users across mobility, power generation, and industrial sectors to reduce emissions using clean renewable hydrogen compared to the cost of other decarbonization pathways such as electrification or CCS. The cost effectiveness of Angeles Link relative to other Non-Hydrogen Alternatives is measured using a set of industry standard cost metrics customized to each end use across mobility, power generation, and industrial sectors.[30]

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[25] The Production Scenarios were informed by the separate Angeles Link Phase 1 Production Study and the Demand Study and are described further in the Routing Analysis and Pipeline Sizing and Design Criteria (Design Study).

[26] Refer to the Design Study for additional information.

[27] Detailed descriptions of the Production Scenarios can be found in Appendix 7.2.1. For additional details on Storage assumptions please refer to Appendix 7.5.1.

[28] The Design Study defined several preferred routes under Scenario 7. The Scenario 7 in this report corresponds to the Scenario 7 Preferred Route Configuration A, which is a single run pipeline design. See the Design Study (Table 17 and Table 19) for additional details. As discussed in the Design Study, the cost difference between the single- and mixed-run configurations ranges from 23% to 32%. The mixed-run configuration did not double the total installed pipe mileage, since only pipelines that were not part of a "looped" configuration were modeled as two-parallel lines (dual-run) to improve system resiliency, allow for continuous operation during potential disruptions, and increase storage capacity during peak usage periods. The resulting cost increase with a mix-run configuration is a relatively small fraction of the overall delivered cost.

[29] ARCHES is a statewide public-private partnership to serve as the applicant and organizer for a statewide clean hydrogen hub in California.

[30] This study is focused on cost and does not estimate a market price for clean renewable hydrogen. For Non-Hydrogen Alternatives, the general approach used in the study was to use the LCOH of Angeles Link as a proxy for the cost of hydrogen in each application, with

- The mobility use case was evaluated based on estimated Total Cost of Ownership (TCO), which reflects the total lifetime cost of owning and operating a vehicle, including purchase cost, maintenance, fuel, and other operational costs.
- The power use case was evaluated based on the estimated Levelized Cost of Electricity (LCOE), which reflects the total lifetime cost of building and operating a power generation (or storage) facility, including capital costs, financing costs, fuel, and other operating costs.
- The industrial use cases were assessed based on metrics tailored to each subsector:
  - Cogeneration: LCOE
  - Refineries: Hydrogen feedstock cost (LCOH)
  - Cement: Fuel cost equivalent ($/MMBtu$_e$)[31]

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additional costs reflected in certain sectors (e.g., cost of last-mile distribution and dispensing for the mobility sector). The hydrogen delivery alternatives are inclusive of all significant costs to estimate the levelized cost of delivered hydrogen as appropriate for the Phase 1 feasibility study analysis. For all delivery alternatives, hydrogen production occurs via PEM electrolyzers that produce hydrogen at a purity of 99.999%. The hydrogen is then delivered via the Angeles Link system to various end uses as described in this study. For the Angeles Link system, delivery is expected to occur at high pressures and without blending, which reduces the risk of potential contamination. For alternatives that utilized underground storage in their configuration, the cost assessment included a Pressure Swing Adsorption (PSA) system to address purification needs. Therefore, it is assumed that no additional significant investments in purification are required.
The comparison of hydrogen alternatives for heavy-duty transportation applications includes additional costs to reflect dispensing and distribution expenses. Dispensing costs do not consider any additional purification. In future phases of design, as specific end-use requirements are established with customers, it may be necessary to consider purification processes at different stages of the Angeles Link system and to implement quality control measures to ensure that the hydrogen delivered meets purity standards for specific end users.
Current hydrogen retail pricing in the California market is specific to hydrogen delivered via gaseous and liquid trucks in relatively small quantities for consumption primarily in the passenger FCEV market. With an anticipated increase in clean renewable hydrogen supply and connective infrastructure, it is expected that the costs of hydrogen on a delivered basis (inclusive of production, transmission, storage, and delivery, as well as additional overhead costs not considered within the scope of this study) will play a significant role as a price setting mechanism for clean renewable hydrogen.
[31] Fuel cost equivalent does not consider capital or other non-fuel operating costs and was used for the purpose of this study in sectors with lower volumes of hydrogen demand projected in the Demand Study – food & beverage and cement. The simplifying assumption is that capital cost is similar across hydrogen-fueled equipment, electrically powered equipment, and CO_2 capture equipment.

- Food & beverage (F&B): Fuel cost equivalent ($\$/MMBtu_e$)[32]

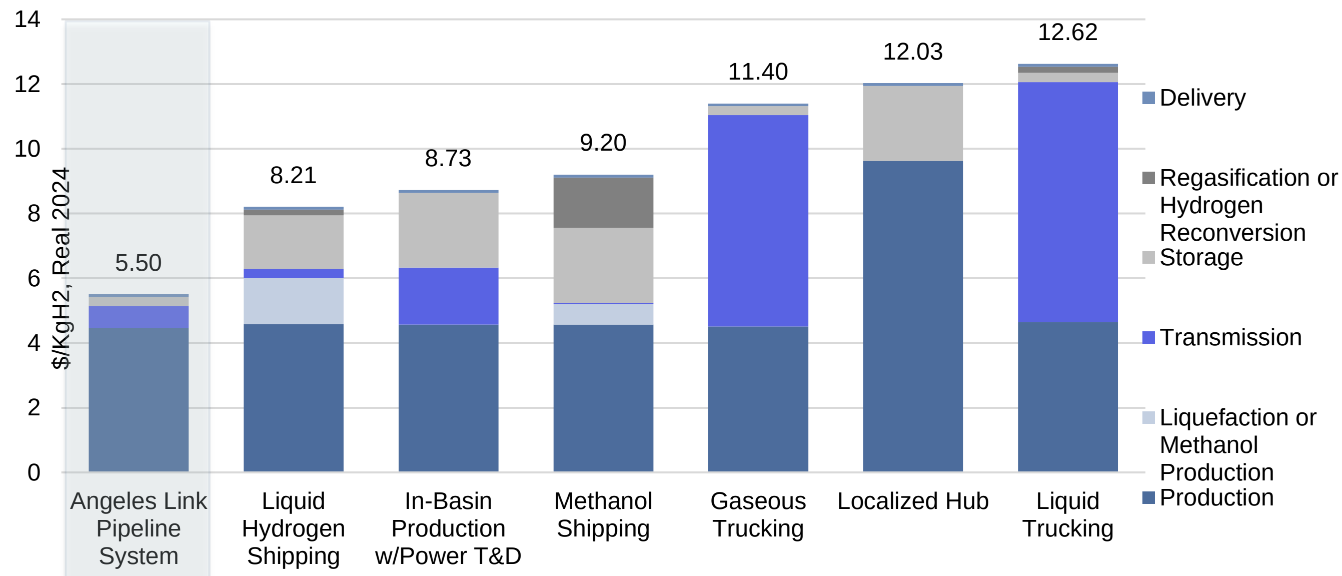
Further discussion on the methodology customized to each group of alternatives is included in Section 4, and additional details on techno-economic assumptions are included in the Appendix.

1.3. Key Findings

1.3.1. Cost Effectiveness of Angeles Link vs. Hydrogen Delivery Alternatives

The cost effectiveness of Angeles Link Scenario 7[33] compared to the Hydrogen Delivery Alternatives is shown in Figure 2 below.

Figure 2: Cost Effectiveness of Angeles Link vs. Hydrogen Delivery Alternatives[34]



Notes: Reflects costs from Scenario 7 for 1.5 Mtpa. Production is assumed to begin in 2030 to take advantage of tax incentives, including Production Tax Credits (PTC) for hydrogen (45V)[35]

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32 Ibid.
33 The Design Study defined several preferred routes under Scenario 7. Scenario 7 in this report corresponds to Scenario 7 Preferred Route Configuration A.
34 See 7.3.1 Delivery Alternatives Assumption Tables and 7.2.2 Delivery Alternatives Descriptions for additional details.
35 Section 45V tax credit for the production of clean hydrogen. See https://www.federalregister.gov/documents/2023/12/26/2023-28359/section-45v-credit-for-production-of-clean-hydrogen-section-48a15-election-to-treat-clean-hydrogen, Section 48(a)(15).

and power (45Y),[36] which provide up to \$3 per kgH_2 and \$0.028 per kWh for ten years. Storage assumptions were based on proximity to production sites, and the geographic footprint under consideration for storage in the Production Study.[37] For Angeles Link and the trucking alternatives (gaseous and liquid), identified routes allowed for access to underground storage sites, therefore, underground storage costs were assumed. Above ground hydrogen storage could be potentially used in the initial phases of demand growth for hydrogen, particularly at a smaller scale. As the hydrogen economy matures and scales over the long term, commercially advanced underground options may provide dependable large-scale hydrogen storage solutions. Even if above ground storage costs were the main medium of storage, Angeles Link remains the lowest cost option when evaluated against the hydrogen delivery alternative options. Delivery alternatives with production sites that did not overlap with the identified geological storage sites, were assumed to rely on above ground storage. These alternatives include shipping, in-basin production with T&D, and localized hub. The shipping solutions include the costs of specialized handling required to deliver methanol and liquid hydrogen. The cost for liquefaction in the liquid hydrogen trucking alternative is included as a part of transmission costs.

- **Angeles Link** was found to be the most cost-effective delivery method when compared to the identified Hydrogen Delivery Alternatives for Phase 1 purposes. It was also found to be the best solution to achieve the scale needed to serve projected demand at the lowest level of logistical complexity. For Angeles Link, like several Hydrogen Delivery Alternatives, the cost of clean renewable hydrogen production is the greatest contributor to total LCOH (as illustrated in Figure 2 above). The Angeles Link pipeline transport and delivery system accounts for around 12% of the total LCOH, making it the most cost-effective solution (when compared to other delivery alternatives) for meeting at-scale demand requirements as identified in the Demand Study.
- **Liquid hydrogen shipping** assumes that clean renewable hydrogen production in and around Central and Northern California regions is liquefied and shipped to L.A. ports. This alternative was found to have a gap to parity with Angeles Link of approximately \$2.71/KgH_2, or approximately 50% higher delivered costs than Angeles Link. The costs of liquid hydrogen shipping are driven by the cost of liquefaction near the export terminal and the need for significant in-basin above-ground hydrogen storage.

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[36] https://www.federalregister.gov/documents/2024/06/03/2024-11719/section-45y-clean-electricity-production-credit-and-section-48e-clean-electricity-investment-credit.

[37] For additional details on the rationale for Storage assumptions from each alternative please refer to Appendix 7.5.1.

Regasification at the destination port incurs additional expenses, as does the unique handling, loading, and unloading infrastructure required close to liquefaction and regasification facilities at each port.

- **In-Basin production with power transmission and distribution (T&D)** assumes renewable electricity is produced outside of the L.A. Basin and transmitted via new high voltage electric transmission lines for hydrogen production in-basin.[38] This alternative was found to have a gap to parity with Angeles Link of $3.23/kg$H_2$, or approximately 60% higher delivered cost than Angeles Link. The higher costs for this alternative are driven by both the scale of high-voltage transmission infrastructure required to deliver the electricity to produce hydrogen in the L.A. Basin and a significant need for expensive above-ground hydrogen storage in the L.A. Basin.[39]
- **Methanol shipping** was evaluated as an alternative based on the potential for clean renewable hydrogen production in and around the Central and Northern California regions that could be converted to methanol. Clean renewable methanol would then be exported, via existing methanol ship technology, and delivered into ports near the L.A. Basin, where it would be reformed (or "cracked") into hydrogen in nearby facilities. The cost of converting hydrogen to methanol, shipping methanol, and then reformulating the methanol back to hydrogen was found to have a gap to parity relative to Angeles Link of $3.70/kg$H_2$, or a more than 65% higher delivered cost than Angeles Link. This finding is primarily driven by the costs associated with additional infrastructure required, including specialized handling equipment to synthesize methanol from hydrogen and crack methanol back to hydrogen and additional supporting infrastructure needed to store the hydrogen using above-ground storage in/around the L.A. Basin. Transporting methanol using ships would also require the construction of loading and unloading facilities near the ports.
- **Gaseous hydrogen trucking** with access to underground storage sites was found to be a sub-optimal delivery alternative from a cost effectiveness perspective to serve the hydrogen volumes required to meet California's decarbonization goals. Gaseous hydrogen trucking was found to have a gap to parity with the Angeles Link scenario of

[38] The number of lines required depends on the power generation capacity and carrying capacity for the distance from supply to sub-station. 26.6 GW is the electricity need for the electrolysis process. Total generation also accounts for transmission losses of 1.8 GW for the scope configuration of Scenario 7 of the in-basin hydrogen production with power T&D alternative. Total installed solar capacity is estimated at 43 GW in the Production Study to account for intra-day availability. Refer to the Cost Effectiveness Study Appendix 7.2.4 and 7.3.1 for additional details.

[39] For additional information on storage assumptions, see Appendix 7.5.1.

almost $6.00/kg$H_2$, or more than double the cost of Angeles Link. This finding is driven by costs associated with the required fleet size, loading time, driving distance, and supporting infrastructure, such as compression terminals, that would need to be located near production and storage sites.

- **A localized hub** assumed local hydrogen production using in-basin renewable electricity generation. The costs of delivered hydrogen produced and delivered via the localized hub were found to be higher than those of Angeles Link by more than $6.00/kg$H_2$. Higher production costs are primarily due to a higher cost of electricity because of the limited land available to develop solar generation capacity at scale within the L.A. Basin. While a localized hub may be a complementary solution to support the early stages of hydrogen throughput growth in a specific region, it carries a higher cost and is scale-limited to meet the projected long-term demand as estimated in the Demand Study.[40]
- **Liquid hydrogen trucking** with access to underground storage sites, like gaseous hydrogen trucking, was found to be a sub-optimal delivery alternative from a cost effectiveness perspective to serve the large volumes and longer transporting distances estimated in the Demand Study. Liquid hydrogen trucking was found to have a gap to parity with Angeles Link of more than $6.00/kg$H_2$. This finding is driven by costs associated with the required fleet size, loading time, driving distance, and supporting infrastructure, such as liquefaction terminals, that would need to be located near multiple production and storage sites.

1.3.2. Cost Effectiveness of Angeles Link vs. Non-Hydrogen Alternatives

As discussed in the Alternatives Study, electrification and CCS were selected as the Non-Hydrogen Alternatives for further evaluation in the Cost Effectiveness Study. The cost effectiveness of these alternatives was analyzed at a use case level in the mobility, power generation, and industrial sectors. For example, the Alternatives Study identified and selected the use cases relevant to electrification, such as comparing fuel cell electric vehicles (FCEV) and battery electric vehicles (BEV) for heavy-duty trucking. It also considered the use cases for CCS, such as comparing hydrogen power plants and natural gas power plants with CCS. Angeles Link and Non-Hydrogen Alternatives were evaluated based on a set of commonly used cost evaluation metrics in the energy industry customized to each use case to ensure a like for like evaluation of the relevant costs across the value chain for each use case. Table 2

[40] Due to land availability constraints in the L.A. Basin area, a localized hub can only provide 9.3% of the 1.5 Mtpa 2045 expected volumetric requirements. See Appendix 7.2.2.5 for additional details.

below summarizes the alternatives, use cases, and metrics used to evaluate cost effectiveness.

Table 2: Mapping of Non-Hydrogen Alternatives to Use Cases and Cost Evaluation Metrics

<table>
<tr><th colspan="2">Sector</th><th>Angeles Link</th><th>Electrification</th><th>CCS</th><th>Cost Evaluation Metric</th></tr>
<tr><td colspan="2">Mobility (long-haul, heavy-duty)</td><td>Fuel cell electric vehicles (FCEV)</td><td>Battery electric vehicles (BEV)</td><td>Not applicable to use case</td><td>TCO[3] ($/mi)</td></tr>
<tr><td colspan="2">Power (clean reliable)[1]</td><td>Hydrogen power plant</td><td>Battery energy storage</td><td>Gas + CCS power plant[2]</td><td>LCOE[4] ($/MWh)</td></tr>
<tr><td rowspan="4">Industrial</td><td>Cogeneration</td><td>Hydrogen cogeneration facility</td><td>Not applicable to use case</td><td>Gas + CCS cogeneration facility</td><td>LCOE[4] ($/MWh)</td></tr>
<tr><td>Refineries (process hydrogen)</td><td>Angeles Link delivery of clean renewable hydrogen</td><td>Not applicable to use case</td><td>Hydrogen abated by CCS</td><td>LCOH[5] ($/kg)</td></tr>
<tr><td>Cement (fuel switching)</td><td>Hydrogen kiln</td><td>Electric kiln</td><td>Gas + CCS kiln</td><td>Fuel cost[6] ($\$/\mathrm{MMBtu}_e$)</td></tr>
<tr><td>Food & Beverage (fuel switching)</td><td>Hydrogen oven/fryer</td><td>Electric oven/fryer</td><td>Not applicable to use case</td><td>Fuel cost[6] ($\$/\mathrm{MMBtu}_e$)</td></tr>
</table>

Note: Certain alternatives were deemed not applicable to some use cases. CCS was deemed not applicable to the mobility sector, or the food & beverage sector given the lack of point source emissions at scale. Electrification was deemed not applicable to cogeneration based on the limited available technology to provide around-the-clock electricity and heat. Electrification is also not applicable to decarbonization of hydrogen for refinery processes (other than through electrolytic hydrogen, which is the purpose of Angeles Link).

1. As established in the Alternatives Study, the power sector is divided into baseload and peaker/reliability use cases. In the baseload use case, hydrogen combustion plants supplied by Angeles Link are compared to gas plants with CCS. In the peaker/reliability use case, hydrogen combustion plants supplied by Angeles Link are compared to battery energy storage facilities.
2. "Gas + CCS" refers to a CO_2 capture technology that captures emissions from an existing facility that combusts natural gas.
3. Total Cost of Ownership (TCO) is measured on a $ per mile basis and reflects the total lifetime cost of owning and operating a vehicle, including purchase cost, maintenance, fuel, and other operational costs.
4. Levelized Cost of Electricity (LCOE) is measured on a $ per MWh basis and reflects the total lifetime cost of building and operating a power generation (or storage) facility, including upfront capital costs, financing costs, and fuel and other operating costs.
5. Levelized Cost of Delivered Hydrogen (LCOH) is measured on a $ per kg basis and reflects the cost of delivered clean renewable hydrogen from Angeles Link (or the cost of adding CCS to unabated hydrogen from existing natural gas-fueled supply).
6. Cement and food & beverage use cases were analyzed based on delivered fuel cost only, with hydrogen (as feedstock) and electricity costs converted to an equivalent $ per MMBtu basis using standard energy value conversions.

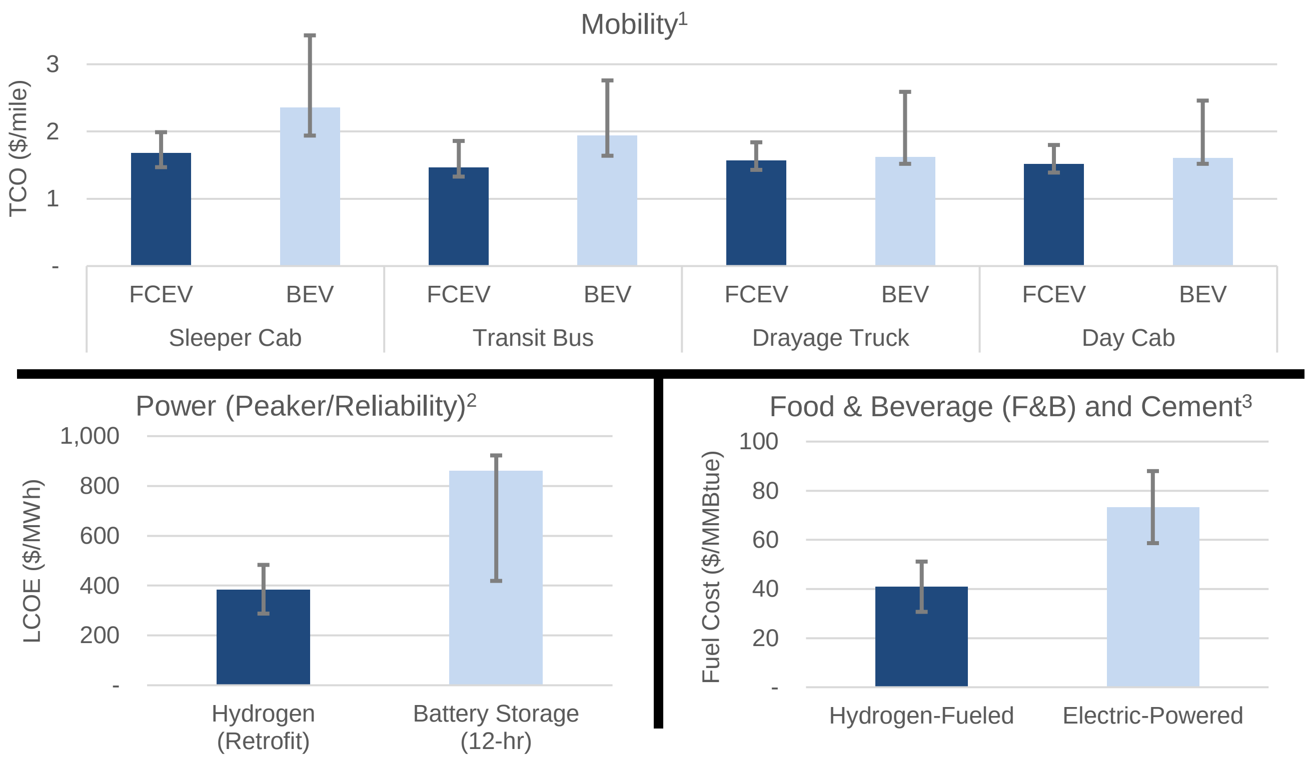
1.3.2.1. Cost Effectiveness of Angeles Link vs. Electrification

The cost effectiveness results for Angeles Link and electrification alternatives across mobility, power, and industrial use cases are shown Figure 3 below. The ranges (shown in Figure 3 in gray bars) reflect a degree of uncertainty in the economic analysis for Phase 1 purposes given the high-level assumptions incorporated, including for capital, fuel, and electricity costs, and other operational considerations. The assumptions underlying these ranges are discussed further in Section 4.2.1, with additional detail provided in Appendix 7.3.2.

Electrification refers to a combination of system level[41] transformation and use case level[42] technology changes, including the grid infrastructure required to support growing electric load. As discussed in the Alternatives Study, the cost effectiveness assessment for electrification was conducted on a use case level for the purposes of this Phase 1 Cost Effectiveness Study. System-level electrification was not assessed as it would necessitate a complex power flow modeling analysis to determine the necessary infrastructure capacity expansion, system interconnections, and system operational requirements to meet North American Electric Reliability Corporation (NERC) reliability standards under loss of load scenarios. An overview of key considerations for the viability of system-level electrification, including the potential cost of supply using wind, solar, and battery storage alone, can be found in the Alternatives Study.[43]

[41] System level electrification includes the incremental electricity generation, storage, and supporting upstream grid infrastructure requirements to meet wide-scale end use electrification needs.
[42] Use-case level electrification implies replacing technologies or processes that use fossil fuels, like internal combustion engines and gas boilers, with electrically powered equivalents, such as electric vehicles or heat pumps.
[43] See Appendix 7.3.2. of the Alternatives Study.

Figure 3: Cost Effectiveness of Angeles Link vs. Electrification Across Use Cases



1. Reflects the total lifetime cost of owning and operating a vehicle, including purchase cost, maintenance, fuel, and other operational costs. Refer to Section 4.2.1.1 for additional details of the cost analysis and Appendix 7.3.2.1 for detailed assumptions.
2. Reflects the total lifetime cost of building and operating a power generation (or storage) facility, including upfront capital costs, financing costs, and fuel and other operating costs. Refer to Section 4.2.1.2 for additional details of the cost analysis and Appendix 7.3.2.2 for detailed assumptions.
3. Reflects only the cost of delivered fuel or electricity to cement and food & beverage facilities. Refer to Section 4.2.1.3 for additional details of the cost analysis and Appendix 7.3.2.4 for detailed assumptions.

In the **mobility** sector, FCEVs (served by clean renewable hydrogen from Angeles Link) have been shown to be more cost effective compared to BEVs (the electrification alternative) for long-haul use cases. This is especially relevant for applications such as Class 8 sleeper cabs and transit buses that require en-route refueling.[44] FCEVs were also found to be a strong competitor for drayage trucks and day cabs, especially when considering the possible range of charging costs. Additionally, factors such as operating patterns based on the vehicle class and fleet operator business models are likely to influence the adoption of these technologies, alongside economic considerations.

In the **power** sector, gas-fueled generation facilities retrofitted to run on clean renewable hydrogen (supplied by Angeles Link) were found to be cost effective relative to longer duration lithium-ion battery storage facilities (the electrification alternative).[45] This is driven by the high estimated capital costs of lithium-ion when sized to this longer-duration capability. Fundamentally, there are few electrification solutions that can provide a direct comparison to Angeles Link for the Central and Southern California power system, where Angeles Link can support both clean firm generation and LDES. The challenges of system-level electrification analysis and the selection of 12-hour lithium-ion as the comparison to Angeles Link in the power sector are discussed in the Alternatives Study.[46]

In the **cement** and **food & beverage** (F&B) sectors, hydrogen-fueled kilns, ovens, and fryers (supplied by Angeles Link) were found to be cost effective relative to electric kilns, ovens, and fryers (the electrification alternative). This is driven by high industrial electricity tariffs in California.

1.3.2.2. Cost Effectiveness of Angeles Link vs. CCS

The cost effectiveness results for Angeles Link and CCS alternatives across power and industrial use cases is shown in Figure 4. The ranges (indicated in gray bars) reflect a degree of uncertainty in the economic analysis given the high-level assumptions incorporated for Phase 1 purposes, including for capital, fuel and electricity costs, and other operational considerations. The assumptions underlying these ranges are discussed further in Section 4.2.2, with additional detail provided in Appendix 7.3.2.

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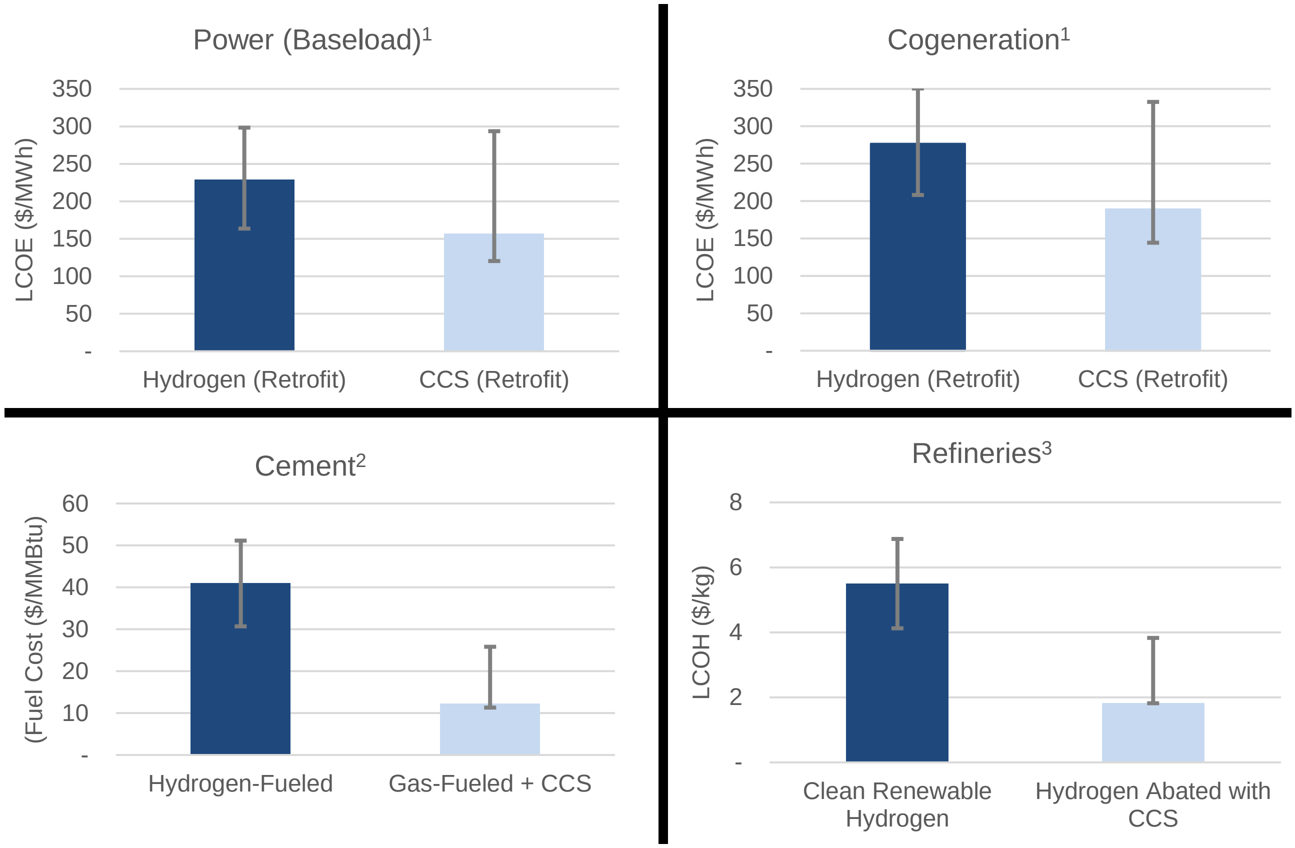
[44] En-route refueling (or charging) involves refueling a vehicle at a retail refueling station located along highways or other convenient locations on major roads or highways. Depot charging involves refueling (or charging) a vehicle, often overnight, in a warehouse or a fleet location where the vehicles are housed after a driver's shift. Source: https://theicct.org/wp-content/uploads/2023/05/infrastructure-deployment-mhdv-may23.pdf

[45] Modeled as three, four-hour units to provide up to 12 hours of discharge duration capability to test the cost of lithium-ion in longer-duration use cases which hydrogen capable of serving.

[46] See Appendix 7.3.2 and 7.3.3 of the Alternatives Study.

Figure 4: Cost Effectiveness of Angeles Link vs. CCS Across Use Cases



1. Reflects the total lifetime cost of building and operating a power generation (or cogeneration) facility, including upfront capital costs, financing costs, and fuel and other operating costs. Refer to Section 4.2.1.1 for additional details of the cost analysis and Appendix 7.3.2 for detailed assumptions.
2. Reflects only the cost of delivered fuel or electricity to cement facilities, in addition to the cost of CO_2 transport and sequestration tariffs. Refer to Section 4.2.2.2 for additional details of the cost analysis and Appendix 7.3.2.5 for detailed assumptions.
3. Reflects the cost of delivered clean renewable hydrogen from Angeles Link or the cost of hydrogen abated with CCS. Refer to Section 4.2.2.3 for additional details of the cost analysis and Appendix 7.3.2.6 for detailed assumptions.

In the **power and cogeneration** sectors, natural gas facilities retrofitted to run on clean renewable hydrogen (supplied by Angeles Link) fall within the range of cost effectiveness relative to natural gas facilities retrofitted with carbon capture equipment (the CCS alternative). While CCS retrofits were found to be more cost effective than clean renewable hydrogen turbines due to the low relative cost of natural gas, CCS adoption will be heavily dependent on site level and regional factors, including geospatial constraints, remaining facility life, and access to CO_2 transport and sequestration infrastructure near point sources, all of which could impact technical feasibility and cost.

In the **cement** sector, hydrogen-fueled kilns (supplied by Angeles Link) were not found to reach cost parity with natural gas-fueled kilns retrofitted with carbon capture equipment (the CCS alternative). This cost gap is primarily driven by the higher cost of clean renewable hydrogen (as a feedstock) relative to natural gas. Given that cost of CCS is likely to be affected by CO_2 transport distances and the accessibility of sequestration locations, there is uncertainty about the ultimate cost of CO_2 transport to end users until system development progresses. CCS adoption is therefore expected to be feasible for cement facilities in proximity to other industrial clusters where there is available CO_2 transport and sequestration infrastructure, and subject to enabling state policy. Senate Bill (SB) 596 requires the cement sector in California to reach net-zero GHG emissions by 2045,[47] and both CCS and hydrogen can be a key enabler to help advance SB 596 goals.

In the **refinery** sector, clean renewable hydrogen supplied by Angeles Link for refinery process use (i.e., hydrotreating) was not found to reach the same level of cost parity with hydrogen abated by carbon capture (the CCS alternative). This cost gap is driven by the higher cost of clean renewable hydrogen (as a feedstock) relative to the cost natural gas with CO_2 capture, transport, and sequestration. Despite the cost effectiveness of CCS for this use case, CCS may face geospatial limitations or may not be viable due to the age of the facility. CCS retrofits for refinery process use versus the use of clean renewable hydrogen will also be influenced by state policy, the availability of CO_2 transport and sequestration infrastructure, and the decarbonization strategies specific to each refinery.

1.3.3. Conclusion

The California Air Resources Board's (CARB) 2022 Scoping Plan identified clean renewable hydrogen as a critical component to achieving California's decarbonization objectives, particularly in hard-to-electrify sectors of the economy.[48] Angeles Link is intended to support the CARB's Scoping Plan and California's decarbonization goals through the delivery of clean renewable hydrogen to serve customers in hard-to-electrify sectors. This study found that for Phase 1 purposes, a pipeline system like Angeles Link offers a cost-effective solution to transport clean renewable hydrogen to serve Central and Southern California, including the L.A. Basin, at scale. Clean renewable hydrogen delivered by Angeles Link was also found to

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[47] https://ww2.arb.ca.gov/our-work/programs/net-zero-emissions-strategy-cement-sector.
[48] See 2022 Scoping Plan Documents | California Air Resources Board, at pp. 9-10, and Senate Bill 100 (SB 100).

be cost effective for Phase 1 purposes relative to electrification and CCS as alternative decarbonization pathways for certain hard-to-electrify industrial sectors, dispatchable power generation, and heavy-duty transportation. While this analysis was required by the CPUC to compare electrification as an “alternative” to Angeles Link, the CARB Scoping Plan supports the finding that a portfolio of pathways, including electrification and clean renewable hydrogen, will be needed to drive the State’s decarbonization goals.

2. Study Background

2.1 Purpose and Objectives of the Study

This study is being prepared pursuant to CPUC Decision (D.22-12-055, Ordering Paragraph [OP] 6(d)). In accordance with OP6(d), this study evaluates the cost effectiveness of Angeles Link against alternatives for Phase 1 purposes and determines a methodology to measure cost effectiveness between alternatives.

The Cost Effectiveness Study considered the alternatives identified in the Alternatives Study (see the Alternatives Study for additional information), developed a methodology to measure the cost-effectiveness between Angeles Link and the alternatives, and performed an analysis of the cost-effectiveness of the alternatives based on that methodology. Specifically, the Cost Effectiveness Study uses a methodology to measure cost effectiveness that includes gathering cost estimates, performing an economic analysis to determine the potential levelized cost of delivered clean renewable hydrogen (LCOH) to end users, and comparing the cost effectiveness of Angeles Link to the identified project alternatives.

The evaluation focused on Hydrogen Delivery Alternatives and Non-Hydrogen Alternatives (as discussed in the Alternatives Study).

This study provides a high-level analysis for Phase 1 purposes of the economics and cost-effectiveness of Angeles Link and selected alternatives and does not evaluate future tariffs or the impact on ratepayers associated with Angeles Link's construction and operation and maintenance costs. That analysis is expected to occur in future phases as Angeles Link is further refined.

2.2 Dependencies with Other Studies

The Cost Effectiveness Study is dependent on several other studies conducted as part of Phase 1 of Angeles Link.

- The Alternatives Study identified and selected the Hydrogen Delivery Alternatives and Non-Hydrogen Alternatives to be analyzed in this study and summarized key findings across economic and non-economic factors.
- The Production Study informed locations of the potential third-party production and potential third-party storage assets, and related costs used to estimate cost effectiveness in the Cost Effectiveness Study.
- The Design Study provided information on the location, sizing, and cost of new clean renewable hydrogen pipeline that was used to estimate cost effectiveness in the Cost Effectiveness Study.

- The Water Resources Evaluation informed the costs related to water supplies for potential third-party clean renewable hydrogen production to estimate cost effectiveness in the Cost Effectiveness Study.

3. Overview of Study Methodology

The Cost Effectiveness Study followed three main stages. The methodology is discussed in further detail in Sections 1.2 and 2.2 for both Hydrogen Delivery Alternatives and Non-Hydrogen Alternatives. Additional detailed assumptions and technical information are also available in the Appendix.

Stage 1: Compile Inputs and Align Scope Configurations on a "Like-for-Like" Basis for Cost Analysis

For Hydrogen Delivery Alternatives, a core principle of the analysis was the consistent application of key project parameters, including a common hydrogen production configuration, end-user delivery system, system throughput expectations (hydrogen volumes), demand profile, and potential storage needs. Many of these elements were defined in the Alternatives Study based on inputs from the Production Study and the Design Study and compiled for cost modeling purposes in this study.

As defined in Table 3, scope configurations for each delivery alternative were customized based on their inherent technical and operational requirements and constraints. Trucking alternatives, which allow for more flexibility, were assumed to connect the same hydrogen production and geological storage locations to demand along similar corridors as those identified for Angeles Link in the Production Study. However, for several other alternatives, solar generation, hydrogen production, and storage sites were adjusted to reduce logistical complexity, while still achieving scale, supporting system reliability and resiliency to the extent possible. For liquid hydrogen and methanol shipping, it was assumed that solar generation and hydrogen production would occur on a more centralized basis, closer to ports in Northern California so that hydrogen could then be shipped to ports in L.A. Basin. As geological storage sites were not identified in Northern California, it was assumed that shipping delivery alternatives would rely on above ground storage. The localized hub alternative was assumed to source power from small-scale solar sources in-basin. The in-basin hydrogen production with power T&D alternative assumed the same power generation locations and capacity as Angeles Link, and the transport of electrons via 500 kV transmission lines generally following similar corridors as Angeles Link.[49] For both localized hub and in-basin hydrogen production

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[49] A 500kV AC transmission system was selected in order to meet the capacity requirements for the Delivery Alternative. The 500kV system is largely compatible with the CAISO grid, which is mostly AC. As discussed in Appendix 7.3.1.2.4, the effective load carrying capacity for a typical 500kV AC transmission system does not exceed 3GW, rapidly declining with the transmitting distance. Hence, supporting 26.6 GW of electricity load requirement (in addition to

with T&D, where hydrogen production occurs in L.A. Basin, above ground storage was assumed, as there were no geological storage sites identified within the L.A. Basin in the Production Study.

For purposes of the cost analysis, Non-Hydrogen Alternatives were defined at a use case level across the mobility, power generation, and industrial sectors as discussed in the executive summary (see Alternatives Study for additional information).

Additional cost and operational input assumptions not available through the Angeles Link Phase 1 feasibility studies were compiled as needed, from public and proprietary sources reflecting market and industry dynamics (e.g., cost assumptions for alternatives, plant size, new build vs. retrofit, capacity factor, etc.).

A summary of each alternative's definition and configuration is included in Section 4, with additional details on techno-economic assumptions in the Appendix.

Stage 2: Establish Methodology for Cost-Effectiveness Analysis

Once scope configurations for the alternatives were defined, a methodology for evaluating cost effectiveness was customized to each group of alternatives (Hydrogen Delivery and Non-Hydrogen).

- The Angeles Link Pipeline System and Hydrogen Delivery Alternatives were assessed based on the Levelized Cost of Delivered Hydrogen (LCOH), which reflects the total lifetime capital and operating costs of all the assets along the hydrogen production, transportation, storage, and delivery value chain.[50]
- Angeles Link Pipeline System and Non-Hydrogen Alternatives were evaluated based on metrics customized to each use case and commonly used in the industry:
    - The mobility use case was evaluated based on estimated Total Cost of Ownership (TCO), which reflects the total lifetime cost of owning and operating a vehicle, including purchase cost, maintenance, fuel, and other operational costs.
    - The power use case was evaluated based on the estimated Levelized Cost of Electricity (LCOE), which reflects the total lifetime cost of building and operating

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the 1.8 GW of transmission load losses) for hydrogen production would require multiple transmission lines consisting of 10 double circuit and 1 single circuit transmission system (for a total of 21 circuits) across a 400 mile transmission corridor (accounting for a total of 2,500 miles of transmission). Refer to Appendix 7.2.2 and 7.3.1 for additional details.

[50] The Angeles Link Pipeline System is proposed to facilitate the transportation of clean renewable hydrogen from multiple regional third-party production source and storage sites to various delivery points and end users in Central and Southern California, including the L.A. Basin.

a power generation (or storage) facility, including capital costs, financing costs, fuel, and other operating costs.

- The industrial use cases were assessed based on metrics tailored to each subsector:
  - Cogeneration: LCOE
  - Refineries: Hydrogen feedstock cost (LCOH)
  - Cement: Fuel cost equivalent ($MMBtu_e$)[51]
  - Food & beverage: Fuel cost equivalent ($MMBtu_e$)[52]

Further discussion on the methodology tailored to each group of alternatives is included in Sections 4.1 and 4.2, with additional details on techno-economic assumptions in the Appendix of this report.

Stage 3: Evaluate Cost Effectiveness

Once the methodology was established, the cost-effectiveness analysis was performed for each group of alternatives. The results of the analysis are discussed in Sections 4.1 and 4.2, with additional details on the evaluation methodology, assumptions and associated sources in the Appendix.

[51] Fuel cost equivalent does not consider capital or other non-fuel operating costs and was used for the purpose of this study in sectors with lower volumes of hydrogen demand projected in the Demand Study – food & beverage and cement. The simplifying assumption is that capital cost is similar across hydrogen-fueled equipment, electrically powered equipment, and CO_2 capture equipment.

[52] Ibid.

4. Key Findings

4.1. Cost Effectiveness of Angeles Link & Hydrogen Delivery Alternatives

This section summarizes the key findings of the analysis comparing the cost effectiveness of the Angeles Link Pipeline System to the identified Hydrogen Delivery Alternatives, as well as the cost effectiveness across the eight Production Scenarios[53] evaluated for the Angeles Link Pipeline System. Each analysis is described below:

- **Angeles Link Pipeline System vs. Hydrogen Delivery Alternatives** compares the cost-effectiveness of Angeles Link and Hydrogen Delivery Alternatives[54] based on a single common set of assumptions[55] for throughput (volume), production areas, and associated supporting infrastructure, including storage,[56] based on Scenario 7.
- **Angeles Link Pipeline System Comparison by Scenario** compares the high-level economics across the eight Production Scenarios defined for Angeles Link in the Design Study, reflecting a range of assumptions for throughput (volume), production areas, and storage types.

The cost effectiveness of the Angeles Link Pipeline System and Hydrogen Delivery Alternatives is evaluated using the Levelized Cost of Delivered Hydrogen (LCOH) in dollars per kilogram ($/kg) of hydrogen delivered. This metric, which accounts for the lifetime cost of all the assets in the hydrogen production, transportation, storage, and delivery value chain is commonly used in the industry to capture the unit costs of hydrogen.[57]

The cost assessments incorporated key input assumptions from other Phase 1 studies, third-party reports,[58] relevant pipeline system costs from SoCalGas, and third-party cost models.

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[53] For additional information on the scenarios, see Appendix 7.2.1.

[54] The Hydrogen Delivery Alternatives were defined, evaluated, and shortlisted in the Alternatives Study. Refer to the Alternatives Study for additional information.

[55] In this section, Angeles Link and Hydrogen Delivery Alternatives are evaluated based on Scenario 7, which is defined in the Design Study. Results of the cost analysis for all Angeles Link scenarios vs. all Hydrogen Delivery Alternatives are provided in Appendix 7.4.1.

[56] For additional information on storage assumptions, see Appendix 7.5.1.

[57] For Hydrogen Delivery Alternatives, LCOH also includes any necessary value chain infrastructure, such as loading, trucking, shipping, liquefaction, compression, power transmission, and other specialized handling like methanol production and reconversion (reforming). The LCOH framework and additional details are provided in Appendix 7.1.1.

[58] Including National Petroleum Council. (2024). https://harnessinghydrogen.npc.org/ and Chen, F., Ma, Z., Nasrabadi, H., Chen, B., Mehana, M. Z. S., & Van Wijk, J. (2024). Capacity Assessment and Cost Analysis of Geologic Storage of Hydrogen: A Case Study in Intermountain-West Region USA. Los Alamos National Laboratory and Texas A&M University.

4.1.1. Angeles Link Pipeline System vs. Hydrogen Delivery Alternatives

The **Angeles Link Pipeline System vs. Hydrogen Delivery Alternatives** analysis compares LCOH across Angeles Link and the six Hydrogen Delivery Alternatives:

1. Liquid hydrogen trucking
2. Gaseous hydrogen trucking
3. Liquid hydrogen shipping
4. Methanol shipping
5. In-basin production with power T&D
6. Localized hub

The scope configuration for Angeles Link and each Hydrogen Delivery Alternative was defined to reflect specific throughput volumes, production areas, and corresponding hydrogen storage[59] as defined for Scenario 7 of Angeles Link in the Design Study and summarized below.[60]

- **Throughput volumes**: 1.5 million tonnes per annum (mtpa).
- **Third-party production centers**: Include production in and around San Joaquin Valley (SJV) and Lancaster. For certain Hydrogen Delivery Alternatives, Northern California or in-basin production were also considered.
- **Third-party storage types:** Include underground storage such as depleted oil and gas reservoirs, as well as above-ground storage.[61]

Scenario 7 was selected as the baseline for the detailed comparison in this chapter due to its alignment with ARCHES and its ability to facilitate transportation of up to 1.5 million tons per year of hydrogen to meet expected demand as defined in the Demand study.[62] Table 3 below summarizes the Scenario 7 configuration applied across the Angeles Link Pipeline System and the Hydrogen Delivery Alternatives.

[59] For additional information on storage assumptions, see Appendix 7.5.1.
[60] The comparison was performed for all eight scenarios; see Appendix 7.4.1 for comparison across scenarios and delivery alternatives.
[61] For additional information on storage assumptions see, Appendix 7.5.1. As discussed in the Production Study, storage can also be provided in the pipeline system through linepack and other methods. Linepack for storage was not included in the Design Study, so it was left out of this analysis.
[62] The Design Study defined several preferred routes under Scenario 7. Scenario 7 in this report corresponds to Scenario 7 Preferred Route Configuration A.

Table 3: Angeles Link Pipeline System vs. Hydrogen Delivery Alternatives Configuration[63]

Angeles Link Scenario	Map	Delivery Methods	Production (mtpa)				Storage	
			SJV	Lancaster	Central/ Northern California	In-Basin	Depleted Oil Fields	Above-Ground
7		Angeles Link Pipeline System	0.75	0.75			✓	
		Gaseous Hydrogen Trucking	0.75	0.75			✓	
		Liquid Hydrogen Trucking	0.75	0.75			✓	
		Liquid Hydrogen Shipping			1.5			✓
		Methanol Shipping			1.5			✓
		In-Basin Production				1.5		✓
		Localized Hub				0.14		✓

Notes: The closer the production center, the less pipeline mileage required, reducing transmission costs. Some scenarios combine different sites. The fewer sites required, the more efficiencies achieved with less pipeline mileage and thus lower transmission costs. Above-ground storage assumes higher relative costs, and among underground storage options, salt caverns are more costly than depleted oil fields.[64] Scenario 7 does not include any

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[63] For Phase 1 cost effectiveness evaluation purposes, production sites were assumed to be close enough to transmission or distribution origination points to not require supply side laterals or interconnections for Angeles Link and Hydrogen Delivery Alternatives.

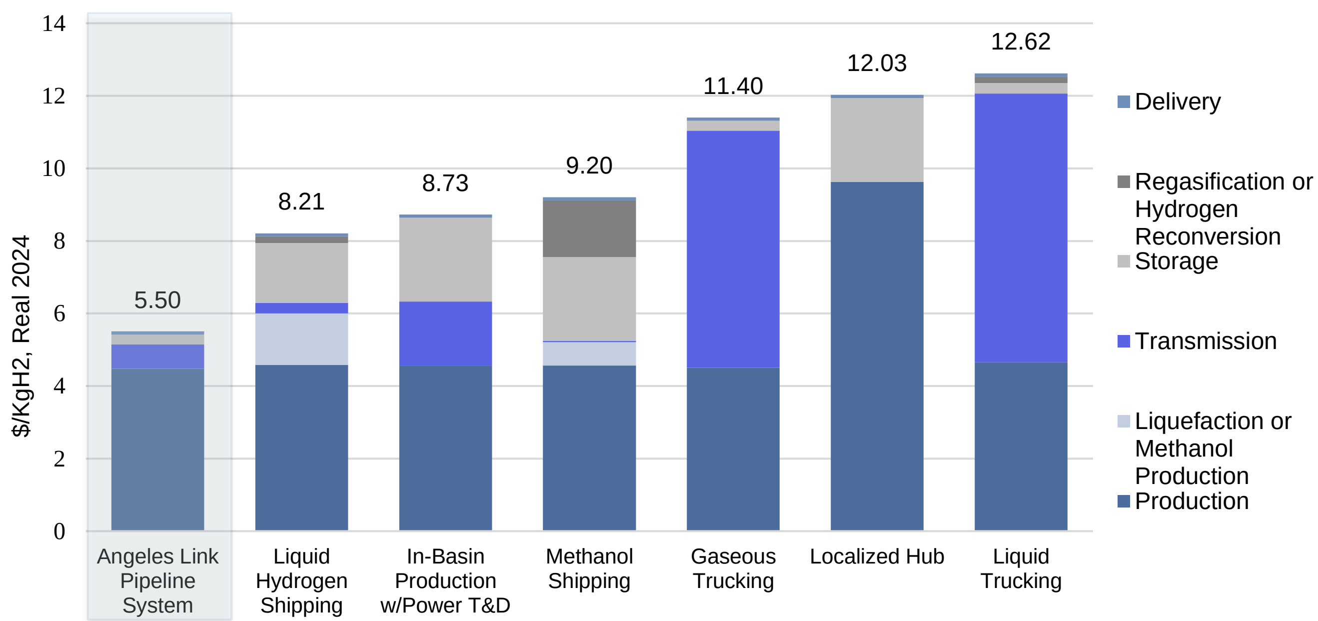
[64] For additional information on storage assumptions, see Appendix 7.5.1.

underground geological salt caverns due to a lack of potential resource availability along the route.

For each alternative, scope configurations were customized based on their inherent technical and operational requirements and constraints. For example, the shipping alternatives assumed production occurs closer to potential export ports, and included additional costs associated with the development of connective infrastructure to transport hydrogen from production areas to ports for shipping.

Figure 5 provides a summary of the results of the LCOH analysis[65] comparing Angeles Link to the selected Hydrogen Delivery Alternatives. The analysis includes all costs from hydrogen production to delivery. The analysis found that Angeles Link is the most cost-effective solution for Phase 1 purposes with an estimated LCOH of \$5.50/kgH_2. The liquid hydrogen trucking alternative was found to have the largest gap to cost parity (over \$6.00/kgH_2) when compared to Angeles Link, with an estimated LCOH of \$12.62/kgH_2.

Figure 5: Cost Effectiveness of Angeles Link vs. Hydrogen Delivery Alternatives[66]



Notes: Reflects costs from Scenario 7 for 1.5 Mtpa. Production is assumed to begin in 2030 to

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[65] A full matrix of LCOH for all scenarios, comparing different throughput volumes, production locations, and storage options, can be found in Appendix 7.4.1.
[66] See 7.3.1 Delivery Alternatives Assumption Tables and 7.2.2 Delivery Alternatives Descriptions for additional details .

take advantage of tax incentives, including Production Tax Credits (PTC) for hydrogen (45V)[67] and power (45Y),[68] which provide up to \$3 per kgH_2 and \$0.028 per kWh for ten years. Storage assumptions were based on proximity to production sites, and the geographic footprint under consideration for storage in the Production Study.[69] For Angeles Link and the trucking alternatives (gaseous and liquid), identified routes allowed for access to underground storage sites, therefore, underground storage costs were assumed (refer to Section 1.3.1 above for additional information on the cost economics of above ground versus below ground storage). Delivery alternatives with production sites that did not overlap with the identified geological storage sites, were assumed to rely on above ground storage. These alternatives include shipping, in-basin production with T&D, and localized hub. The shipping solutions include the costs of specialized handling required to deliver methanol and liquid hydrogen. The cost for liquefaction in the liquid hydrogen trucking alternative is included as a part of transmission costs.

Table 4 below details the costs for each segment of the value chain for Angeles Link and each Hydrogen Delivery Alternative.

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[67] Section 45V tax credit for the production of clean hydrogen. See https://www.federalregister.gov/documents/2023/12/26/2023-28359/section-45v-credit-for-production-of-clean-hydrogen-section-48a15-election-to-treat-clean-hydrogen, Section 48(a)(15).

[68] https://www.federalregister.gov/documents/2024/06/03/2024-11719/section-45y-clean-electricity-production-credit-and-section-48e-clean-electricity-investment-credit.

[69] For additional details on the rationale for Storage assumptions from each alternative please refer to Appendix 7.5.1.

Table 4: Angeles Link and Hydrogen Delivery Alternatives Cost by Value Chain Component

Cost Component ($/Kg$H_2$)	Angeles Link Pipeline System	Liquid Hydrogen Shipping	In-Basin Production w/Power T&D	Methanol Shipping	Gaseous Hydrogen Trucking	Localized Hub	Liquid Hydrogen Trucking
Delivery[70]	$0.08	$0.08	$0.08	$0.08	$0.08	$0.08	$0.08
Regasification or Hydrogen Reconversion[71]	N/A	$0.18	N/A	$1.56	N/A	N/A	$0.18
Storage[72]	$0.28	$1.65	$2.31	$2.31	$0.28	$2.31	$0.29
Transmission	$0.67	$0.29	$1.76	$0.04	$6.53	N/A	$7.41
Liquefaction or Methanol Production	N/A	$1.42	N/A	$0.64	N/A	N/A	Included in transmission
Production[73]	$4.47	$4.59	$4.58	$4.57	$4.51	$9.64	$4.66
Total LCOH	**$5.50**	**$8.21**	**$8.73**	**$9.20**	**$11.40**	**$12.03**	**$12.62**

Notes: Reflects costs from Scenario 7 for 1.5 Mtpa. Production is assumed to begin in 2030 to take advantage of tax incentives, including production tax credits (PTC) for hydrogen (45V)[74]

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[70] As discussed in the Design Study (see Figure 7 Route A Map), the pipelines within Central Zone to the Ports of Los Angeles and Long Beach (Point 4 to 5) were calculated to require 80 miles for the single-run configuration. To adhere to the principle of comparing delivery alternatives on a like-for-like basis, all delivery alternatives assumed an approximately 80-mile delivery system. For additional details, refer to Appendix 7.3.1.5.

[71] Regasification or hydrogen reconversion are part of the transportation process for liquid hydrogen shipping, methanol shipping and liquid hydrogen trucking. These processes are not used for the other Hydrogen Delivery Alternatives

[72] Underground storage was assumed for Angeles Link and the trucking alternatives. All other Hydrogen Delivery Alternatives were assumed to have above-ground storage. For additional information on storage assumptions see Appendix 7.5.1.

[73] While production costs were the same, each delivery alternative had different losses (per Appendix 7.3.1.7) along the value chain, which means the LCOH would show slight variations.

[74] Section 45V tax credit for the production of clean hydrogen. See https://www.federalregister.gov/documents/2023/12/26/2023-28359/section-45v-credit-for-production-of-clean-hydrogen-section-48a15-election-to-treat-clean-hydrogen, Section 48(a)(15).

and power (45Y),[75] which provide up to $3 per kgH_2 and $0.028 per kWh for ten years. Due to the hydrogen production locations identified for some alternatives, the Angeles Link Pipeline System and the trucking alternatives (gaseous and liquid) assume underground storage, while other alternatives assume above-ground storage.[76] The shipping solutions include the costs of specialized handling required to deliver methanol and liquid hydrogen. The cost for liquefaction in the liquid hydrogen trucking alternative is included as a part of transmission costs.

Figure 5 and Table 4 show the following key results:

- **The Angeles Link Pipeline System** was found to be the most cost-effective solution for delivering hydrogen at scale across Central and Southern California, including the L.A. Basin. The cost of clean renewable hydrogen production represents over 80% of the total LCOH of $5.50/$kgH_2$. In comparison, the cost of the pipeline transport and delivery system represents approximately 12% of the total LCOH, and the cost of storage represents 5% of the total LCOH.
- **Liquid hydrogen shipping** assumes that clean renewable hydrogen production in and around Central and Northern California regions is liquefied and shipped to the ports in the L.A. Basin. This alternative was found to have an LCOH of $8.21/$kgH_2$, or approximately 50% higher than Angeles Link. The costs of liquid hydrogen shipping are driven by the cost of liquefaction near the export terminal and the need for significant in-basin above-ground hydrogen storage, which combined reflect 37% of the total LCOH. Regasification at the destination port would incur additional expenses, as would the unique handling, loading, and unloading infrastructure required close to liquefaction and regasification facilities at each port.
- **In-basin production with power T&D** was found to have an LCOH of $8.73/$kgH_2$, as it would require extensive and costly infrastructure compared to Angeles Link Pipeline System, since new long-distance electric transmission lines[77] would be needed to bring

[75] https://www.federalregister.gov/documents/2024/06/03/2024-11719/section-45y-clean-electricity-production-credit-and-section-48e-clean-electricity-investment-credit.
[76] For additional details on the rationale for Storage assumptions from each alternative please refer to Appendix 7.5.1. the storage solution selected reflects the best available for a like for like comparison.
[77] The number of lines required depends on the power generation capacity and carrying capacity for the distance from supply to sub-station. 26.6 GW is the electricity need for the electrolysis process. Total generation also accounts for transmission losses of 1.8 GW for the scope configuration of Scenario 7 of the in-basin hydrogen production with power T&D alternative. Total installed solar capacity is estimated at 43 GW in the Production Study to account for intra-day availability. See Appendix 7.2.2 and 7.3.1 for additional details.

the power to in-basin hydrogen production centers and would require in-basin above-ground storage near the in-basin production facilities. Costs associated with long-distance transmission coupled with in-basin above-ground storage[78] represent approximately 47% of the total LCOH, and result in a significant increase in the cost of delivered hydrogen.

- **Methanol shipping** assumed clean renewable hydrogen production in and around the Central and Northern California regions with conversion to methanol. Clean renewable methanol would then be exported via existing methanol shipping technology and reformed (or "cracked") into hydrogen upon delivery to ports in the L.A. Basin. The cost of this complex value chain was estimated at \$9.20/kgH_2, or 65% higher than Angeles Link. This is primarily driven by the costs associated with additional infrastructure requirements, including specialized handling equipment to synthesize methanol from hydrogen and crack methanol back to hydrogen, in addition to above-ground hydrogen storage in and around the L.A. Basin. Transporting methanol using ships would also require the construction of loading and unloading facilities near the ports. These additional steps in the value chain reflect roughly 49% of the total LCOH.
- **Gaseous hydrogen trucking** with access to underground storage sites was found to be sub-optimal from a cost effectiveness perspective to serve the volumes required to meet California's decarbonization goals. Gaseous hydrogen trucking was found to have a delivered cost of hydrogen of \$11.40/kg, or more than double the cost of Angeles Link. This is driven by costs associated with the required fleet size, loading time, driving distance, and supporting infrastructure such as compression terminals needed in multiple hydrogen production and storage sites. These additional steps in the value chain result in transmission costs of \$6.53/kgH_2, or roughly 57% of the total LCOH.
- **The localized hub**, which assumed local hydrogen production using in-basin renewable electricity generation, was found to have the highest hydrogen production costs at \$9.63/kgH_2. Higher hydrogen production costs are primarily driven by the higher cost of electricity due to limited land available within the L.A. Basin for the development of solar generation capacity at scale. The localized hub would also rely on above-ground hydrogen storage in-basin. As a result of these challenges, the LCOH across the entire value chain for the localized hub was estimated at \$12.03/kgH_2.
- **Liquid hydrogen trucking** with access to underground storage sites, like gaseous hydrogen trucking, was found to be sub-optimal from a cost effectiveness perspective to serve the large volumes and long distances required. Liquid hydrogen trucking was found to have a delivered LCOH of \$12.62/kgH_2, or more than double the cost of

[78] More details on above-ground storage costs can be found in Appendix 7.5.1.

Angeles Link. This is driven by costs associated with the required fleet size, loading time, driving distance, and supporting infrastructure such as liquefaction terminals needed at multiple production and storage sites. As a result of these additional steps in the value chain, liquid hydrogen trucking transmission costs reflect 59% of the total LCOH.

4.1.2. Angeles Link Comparison by Scenario

Eight Production Scenarios were modeled for Angeles Link (as defined in the Design Study) reflecting various throughput volumes, production areas, and hydrogen storage types:

- **Throughput volumes**: Range from 0.5 to 1.5 million tonnes per annum (mtpa).
- **Third-party production centers**: Include production in and around SJV, Lancaster, and Blythe areas.
- **Third-party storage types:** Include underground storage such as depleted oil and gas reservoirs and salt caverns, as well as above-ground storage.[79]

The scenario configurations for the Angeles Link Pipeline System are presented in Table 5 below.[80]

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[79] For additional information on storage assumptions, see Appendix 7.5.1. As discussed in the Production Study, storage can also be provided in the pipeline system through linepack and other methods. Linepack for storage was not included in the Design Study, so it was left out of this analysis.

[80] For additional details, see Table 15 in the Appendix.

Table 5: Scenario Description for Angeles Link Pipeline System[81]

Scenario	Throughput Volumes	Hydrogen Production (mtpa)			Angeles Link Pipeline System Miles[82]	Hydrogen Storage	
		SJV	Lancaster	Blythe		Depleted Oil/Gas Reservoirs	Salt Caverns
1	0.5 Mtpa	0.5			355	✓	
2			0.5		314	✓	
3				0.5	303[83]		✓
4	1.0 Mtpa	0.5	0.5		392	✓	
5			0.5	0.5	537[83]	✓	✓
6		0.5		0.5	578[83]	✓	✓
7	1.5 Mtpa	0.75	0.75		390	✓	
8		0.5	0.5	0.5	616[83]	✓	✓

The variability in LCOH across the scenarios is driven by differences in throughput volumes and transport distance (mileage) between production areas, hypothetical storage sites,[84] and end users. The result of the cost effectiveness analysis for each scenario are summarized in Figure 6 below. The LCOH is represented in columns to illustrate the value chain costs to produce, store, transport, and deliver hydrogen.

The results show the most cost-effective configurations have the largest throughput volumes and the shortest distances between third-party production and storage locations and end users. Figure 6 below illustrates the range of costs based on each scenario.

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[81] Per the Production Scenarios defined in the Pipeline Sizing and Design Studies.

[82] As discussed in the Design Study (see Figure 7 Route A Map), the pipelines within the Central Zone to the Ports of Los Angeles and Long Beach (Point 4 to 5) were calculated to require 80 miles for the single-run configuration. To adhere to the principle of comparing delivery alternatives on a like-for-like basis, all delivery alternatives assumed an approximately 80-mile delivery system. For additional details, refer to Appendix 7.3.1.5.

[83] Given salt cavern storage, the transmission pipeline requires an additional 100 miles, which were included in the cost assumptions for the scenarios that have production at Blythe as the salt cavern storage access needs are near Phoenix, Arizona.

[84] For additional information on storage assumptions see Appendix 7.5.1.

Figure 6: Cost Effectiveness of Angeles Link Pipeline System by Scenario[85]

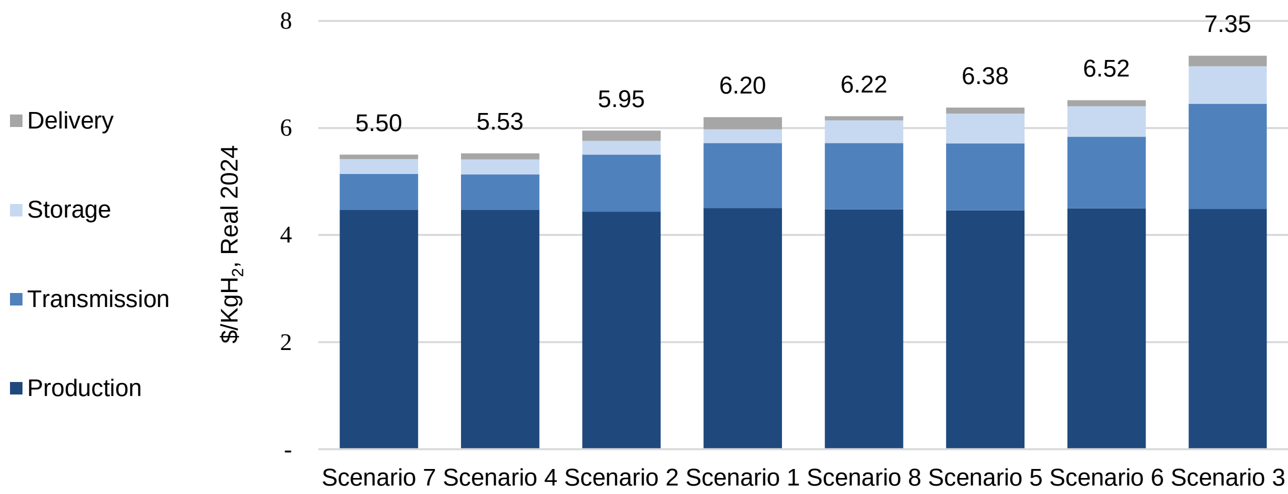

Table 6 below details the LCOH for each segment of the value chain across the scenarios.

[85] Additional information on the scenarios can be found in the Appendix 7.2 of this study. Refer to the Design Study for a detailed assessment of all scenarios. To adhere to the principle of comparing delivery alternatives on a like-for-like basis, all delivery alternatives assumed an approximately 80-mile delivery system. For additional details, refer to Appendix 7.3.1.5.

Table 6: Cost Effectiveness by Angeles Link Scenario[86]

Component	Scenario 7	Scenario 4	Scenario 2	Scenario 1	Scenario 8	Scenario 5	Scenario 6	Scenario 3
Throughput (Mtpa)	1.5	1.0	0.5	0.5	1.5	1.0	1.0	0.5
# of System Miles[87]	390	392	314	355	616[62]	537[62]	578[62]	3038[88]
Storage Type	Depleted Oil/Gas Res.	Depleted Oil/Gas Res.	Depleted Oil/Gas Res.	Depleted Oil/Gas Res.	Depleted Oil/Gas Res./Salt Caverns	Depleted Oil/Gas Res./Salt Caverns	Depleted Oil/Gas Res./Salt Caverns	Salt Caverns
Delivery[89] ($/Kg$H_2$)	$0.08	$0.11	$0.19	$0.23	$0.08	$0.11	$0.11	$0.20
Third-Party Storage ($/Kg$H_2$)	$0.28	$0.28	$0.25	$0.26	$0.42	$0.56	$0.56	$0.70
Transmission ($/Kg$H_2$)	$0.67	$0.66	$1.06	$1.21	$1.24	$1.25	$1.34	$1.97
Third-Party Production[90] ($/Kg$H_2$)	$4.47	$4.47	$4.44	$4.51	$4.48	$4.46	$4.50	$4.49
Total Costs ($/Kg$H_2$)	**$5.50**	**$5.53**	**$5.95**	**$6.20**	**$6.22**	**$6.38**	**$6.52**	**$7.35**

The scenario analysis indicated the following general conclusions:

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[86] Additional information on the scenarios can be found in the Appendix 7.2 of this study. Refer to the Design Study for a detailed assessment of all scenarios.
[87] Includes ~80-miles for delivery infrastructure.
[88] To integrate inter-state salt cavern storage (in Arizona), an additional 100 miles of pipeline routing would be needed and was considered as part of the cost evaluation for the appropriate scenario under evaluation.
[89] To adhere to the principle of comparing delivery alternatives on a like-for-like basis, all delivery alternatives assumed an approximately 80-mile delivery system. For additional details, refer to Appendix 7.3.1.5.
[90] Assumes 45V Production Tax Credit (PTC) for ten years.

- Production costs remain similar across all scenarios, while transmission costs vary due to differences in pipeline mileage and throughput volumes.
- Scenarios with the highest throughput of 1.5 Mtpa were found to have lower costs as the scale helps bring down the cost on a per unit basis. Additionally, pipeline transportation costs are lowest in scenarios where third-party production locations require minimal pipeline mileage due to their proximity to the L.A. Basin. Furthermore, the availability of underground storage sites, especially depleted oil and gas reservoirs that may be closer to production sites, would support lower delivery costs compared to other scenarios.
- Scenario 7, at $5.50 per kg$H_2$, was found to be the most cost-effective scenario. This is driven by the scale of throughput, the proximity of potential third-party production areas (such as SJV and Lancaster) to the L.A. Basin, and the underground storage resources that may be developed over time as demand for clean renewable hydrogen scales over the planning horizon as discussed in the Demand Study.
- Scenario 3, at $7.35 per kg$H_2$, was found to have the greatest gap to parity with Scenario 7. This is driven by longer pipeline lengths (mileage) to connect a lower throughput of hydrogen from potential third-party production locations further from the L.A. Basin, (such as Blythe) and the integration of inter-state geologic storage resources (such as salt caverns in Arizona).

4.2. Cost Effectiveness of Angeles Link & Non-Hydrogen Alternatives

This section describes the findings from the cost-effectiveness analysis of Angeles Link vs. Non-Hydrogen Alternatives (electrification and CCS) across a range of specific use cases in mobility, power, and industrial sectors. Each subsection provides an overview of the use cases and methodology, results of the cost analysis, a discussion of the sensitivity ranges applied to key assumptions, and a summary of non-economic considerations identified in the Alternatives Study.

4.2.1. Cost Effectiveness of Angeles Link vs. Electrification

Details of the four use case analyses are below, comparing Angeles Link to electrification across the following applications:

- **Mobility**: FCEV vs. BEV for long-haul, heavy-duty applications.
- **Power**: Hydrogen-fueled combustion plant vs. 12-hour battery energy storage facility for peaking and reliability needs.
- **Food & beverage (F&B)**: Hydrogen-fueled ovens/fryers vs. electric ovens/fryers.
- **Cement**: Hydrogen-fueled kilns vs. electric kilns.

4.2.1.1. Mobility

The mobility end use evaluation compared hydrogen FCEVs (supplied by Angeles Link) vs. BEVs (the electrification alternative). Specifically, both FCEVs and BEVs are evaluated for the four primary long-haul, heavy-duty applications described in the Demand Study: sleeper cab, transit bus, drayage truck, and day cab. These applications, as detailed in the Demand Study, have the greatest hydrogen adoption potential due to their operational requirements (including high payloads, long routes, and high duty cycles). To determine cost effectiveness in the mobility sector, a TCO analysis was conducted to capture the lifetime ownership and operational costs across the modeled vehicle classes.

Table 7: Configurations and Cost Metrics for Mobility

Mobility Use Case	Alternative	Technology Application	Cost Metric
• Sleeper Cab • Transit Bus • Drayage Truck • Day Cab	**Angeles Link**	Fuel Cell Electric Vehicle	Total Cost of Ownership (TCO) ($/mile)
	Electrification	Battery Electric Vehicle	

The TCO analysis was derived from third-party models,[91] which include inputs from a combination of market intelligence and national lab research (including Argonne National Lab, the National Renewable Energy Laboratory (NREL) and other relevant industry related sources). The TCO includes the typical costs associated with purchasing, fueling/charging, and maintaining vehicles, in addition to other operational factors, including labor, dwell and payload costs.[92] The operations component of the TCO includes the following key drivers:

- Labor cost represents the cost of the driver's time during a shift.
- Dwell cost reflects the opportunity cost associated with queueing and refueling/charging times.
- Payload costs reflect the indirect cost from reduced payload capacity to accommodate the weight of batteries or fuel cell stacks relative to diesel engines.

Sensitivity analysis across the FCEV and BEV purchase cost, fuel/charging cost, and operational patterns influence the overall TCO. The vehicles' refueling patterns, changes in incentives, and fuel cost uncertainty could have a significant impact on a vehicle's overall cost of ownership. The implications of these sensitivities are discussed below. Additional details of the TCO modeling assumptions including sensitivities can be found in Appendix 7.3.2.1.

4.2.1.1.1.Cost Analysis Results

As shown in Figure 7, the findings indicate FCEVs are cost-effective relative to BEVs for the two vehicle classes (sleeper cabs and transit buses) with longer range requirements and en-route refueling needs. The TCO analysis shows directional cost-parity (where the cost of ownership over the economic life of a vehicle is almost the same) for vehicle classes such as drayage trucks and day cabs. This cost equivalence is due to these applications typically traveling shorter distances in a duty cycle and taking advantage of depot refueling, which can offset refueling expenses over the course of a vehicle's economic life. Additional findings from the TCO analysis across the four modeled vehicle classes are discussed below.

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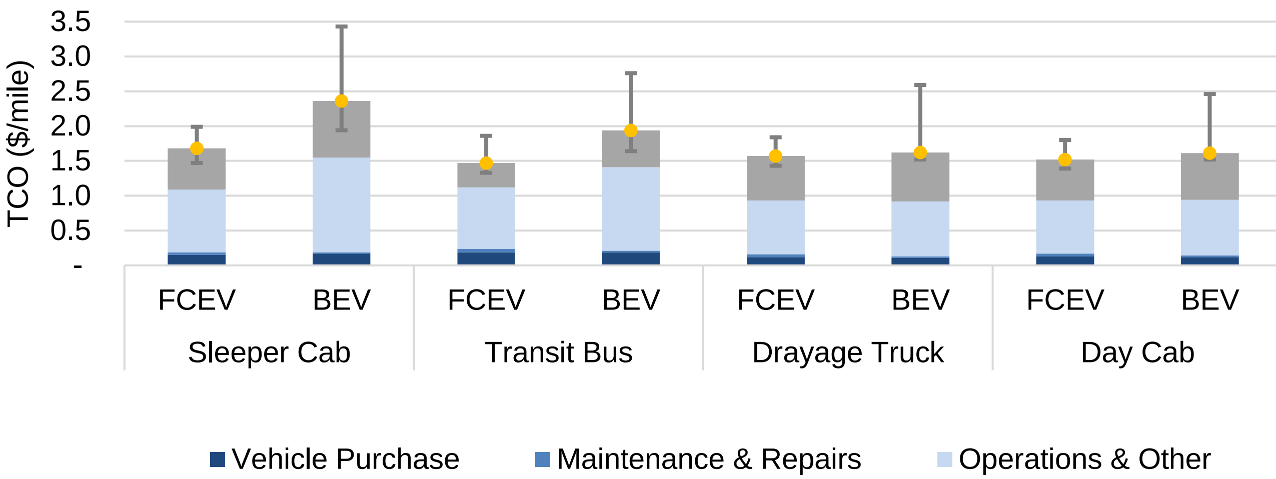
[91] Third-party TCO models, with input assumptions detailed in Appendix 7.1.3.
[92] The TCO for this cost effectiveness analysis excludes insurance, registration, tolls and parking.

Figure 7: Cost Effectiveness: Mobility (2030)[93]



Sleeper cab and transit bus: These two vehicle classes were found to show the greatest cost advantage for FCEV over BEV. The TCO for sleeper cab FCEV ranges from $1.5 - $2.0 per mile vs. $1.9 - $3.4 per mile for BEV. The TCO for transit bus FCEV ranges from $1.3 - $1.9 per mile vs. $1.6 - $2.8 per mile for BEV. The lower cost for FCEVs is primarily driven by lower operational costs due to faster refueling (reflected in lower dwell costs) compared to BEVs. Sleeper cabs and transit buses often refuel while on the road during a driver's shift, and the study assumes BEVs will face high charging costs at retail stations based on commercial models in the market today and the high electricity tariffs in California.[94]

Drayage truck and day cab: These vehicle classes offer directional cost parity between FCEV and BEV technology, although BEV models are not at cost parity at the higher end of the sensitivity range given the large range of charging costs observed in the market. The TCO for drayage truck FCEV ranges from $1.4 - $1.8 per mile vs. $1.5 - $2.6 per mile for BEV. The TCO for day cab FCEV ranges from $1.4 - $1.8 per mile vs. $1.5 - $2.5 per mile for BEV. The Demand Study describes the duty cycle of drayage trucks, which are primarily involved in port operations, operating around the clock across multiple shifts, and refuelling at a central depot. Day cabs typically operate in 8-hour duty cycles, do not run around the clock, and refuel at a central depot. This depot refueling pattern results in parity in operational and fuel costs

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[93] Assumes that both FCEVs and BEVs travel 100,000 miles a year and have an economic life of 10-12 years. The range in gray depicts the range of estimation and sensitivity analysis in the TCO across key assumptions. Detailed assumptions are provided in Appendix 7.3.2.1.

[94] Southern California Edison (SCE) Schedule TOU-D-PRIME. The retail rate used in this analysis was a weighted average of SCE bundled time-of-use rates.

between FCEV and BEV, as longer BEV charging times are not considered to make an economic impact, and depot charging is assumed to come at lower cost than en-route retail charging.[95]

4.2.1.1.2. Key Sensitivities: Operational Costs and Fuel/Charging Costs

Two of the most critical drivers of the TCO analysis are the operational costs and the fuel/charging costs. These assumptions and the analyzed sensitivities are discussed in greater detail below.

Operational Costs

Operational costs include labor, payload, and dwell time.[96] Expenses associated with dwell time (dwell cost), is the cost component that most influences the relative parity of FCEVs and BEVs, driven by the longer charging time of BEVs. The study treats dwell time costs differently based on the distinction between en-route or depot refueling/charging patterns. Sleeper cab and transit bus applications are assumed to use primarily en-route refueling, and the study incorporates dwell cost into the TCO for this pattern to reflect the economic impact of refueling/charging time during the duty cycle. Alternatively, drayage truck and day cab applications are assumed to use primarily depot refueling, and the study assumes zero dwell cost in the TCO for this pattern as the time spent refueling/charging is primarily post-duty cycle. Sensitivities were used to test different percentage mixes of the two refueling/charging patterns, as well as potential improvements in BEV charging times, with the impact on dwell times and overall operations costs across sensitivities shown in the Figure 8 below.

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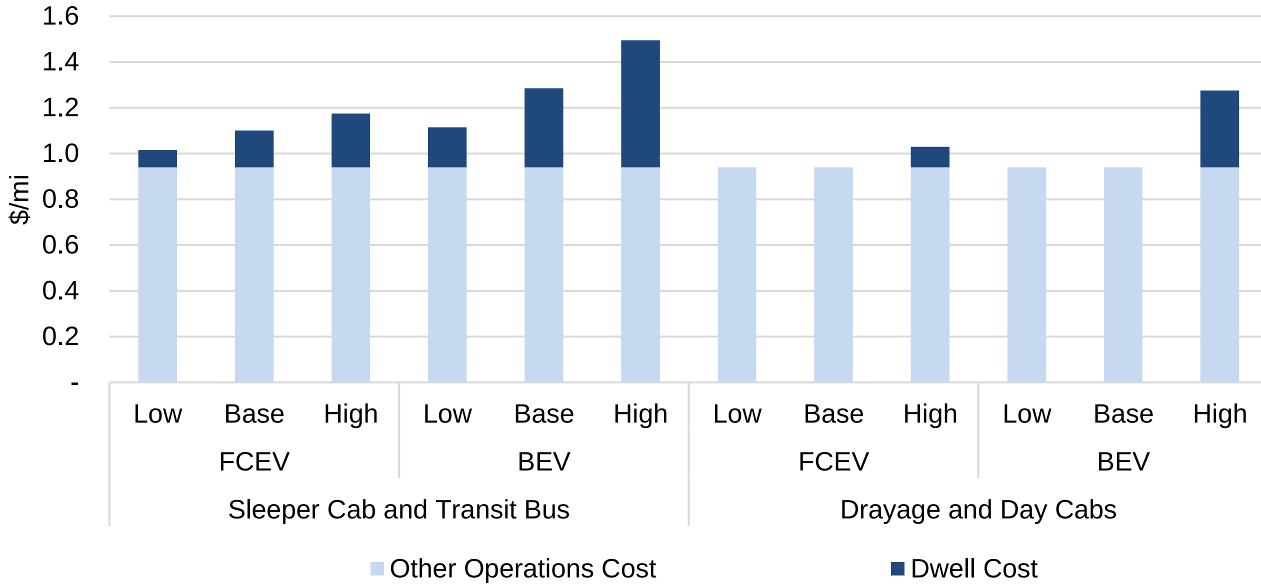
[95] En-route charging involves refueling a vehicle at a retail refueling station located along highways or other convenient locations on major roads or highways. Depot charging involves refueling a vehicle, often overnight, in a warehouse or a fleet location where the vehicles are housed after a driver's shift. Based on the assumption that on-the-road retail charging stations charge a higher markup to recover a return on investment for charging infrastructure investment. Source: https://theicct.org/wp-content/uploads/2023/05/infrastructure-deployment-mhdv-may23.pdf.

[96] Dwell time is the time a vehicle stops for refueling or charging at a fueling or electric charging station.

Figure 8: Dwell Cost Proportion of Total Operations Costs Across Sensitivities[97]



Fuel/Charging Costs

Fuel/charging cost is a key component driving the TCO and is primarily influenced by feedstock costs for hydrogen for the FCEVs and electric charging costs for the BEVs. The hydrogen fuel costs reflect the estimated LCOH for Angeles Link. This cost includes delivery of the fuel to a central point in the L.A. Basin and operation of an approximately 80-mile delivery pipeline system. An additional cost for last-mile distribution and dispensing has been included to account for the expenses associated with delivering the product to the refueling station and the cost of the refueling equipment. The costs of hydrogen fuel also include the assumption that station owners will have access to Low Carbon Fuel Standard (LCFS)[98] credits, which can be passed on to customers.

Electric charging costs include current electricity tariffs available to commercial scale electric charging stations, estimated costs of the station (including the charging equipment and associated power infrastructure), the cost of renewable electricity certificates (RECs) to offset

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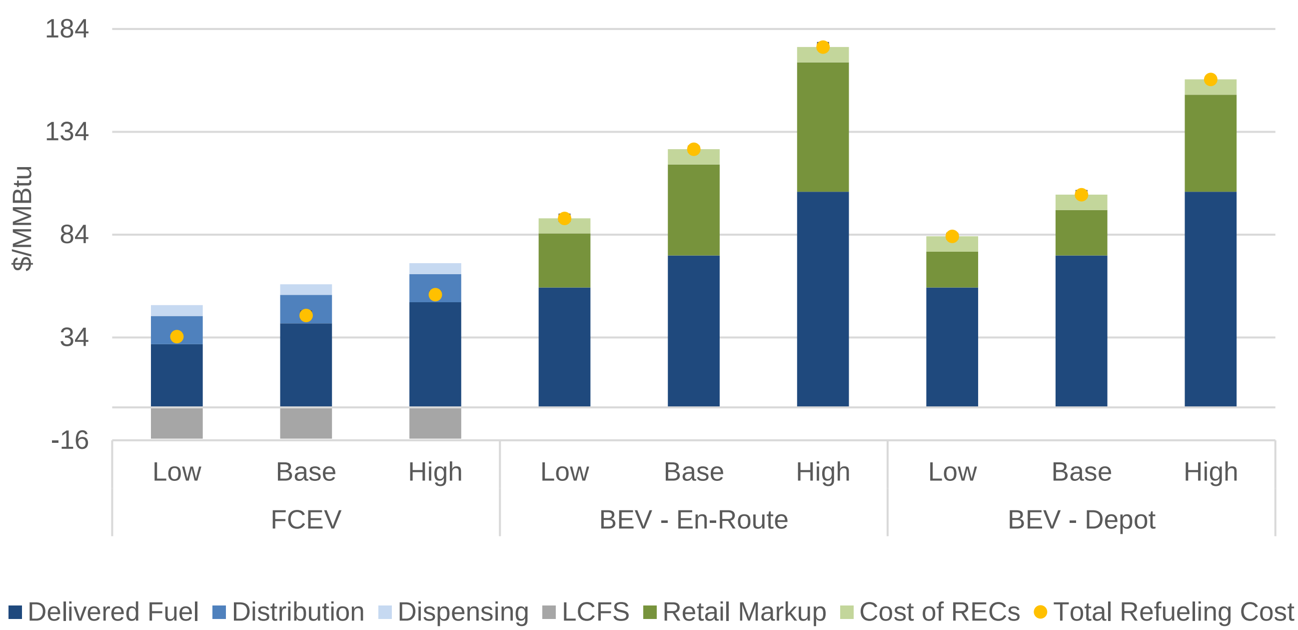
[97] Refer to Appendix 7.3.2.1 for the underlying data assumptions reflected in the Low, Base and High sensitivity cases

[98] https://ww2.arb.ca.gov/our-work/programs/low-carbon-fuel-standard

the carbon footprint of grid electricity, and a retail markup[99] to align with prices observed in the California market. This retail markup was adjusted depending on the en-route vs. depot charging pattern to reflect the assumption that en-route charging typically comes with higher retail prices, while depot or centralized charging can provide lower prices based on customer-owned infrastructure or third-party infrastructure with lower required returns. Sensitivities were performed to capture the various levels of uncertainty in fuel/charging costs in general, as well as to specifically examine different percentage combinations of en-route and depot charging patterns. Figure 9 below displays a breakdown of the components and variations in fuel/charging costs across different sensitivities.

Figure 9: Fuel/Charging Cost Breakdown by Technology and Refueling Pattern[100]



Note: Hydrogen in $/kg and electricity in $/kWh were converted to a common unit ($/MMBtu) from an energy equivalency basis for purposes of a direct comparison above. The LCFS for BEVs are included in the retail markup cost component of the fuel cost.

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[99] About 30% for depot and 60% for en-route refueling patterns, with additional considerations taken to incorporate any incentives, such as LCFS. Additional details provided in Appendix 7.3.2.1.

[100] Refer to Appendix 7.3.2.1 for the underlying data assumptions reflected in the Low, Base and High sensitivity cases.

4.2.1.1.3.Non-Economic Considerations

Based on the analysis of the four vehicle classes above, it was determined that both FCEVs and BEVs fall within cost parity across the specified sensitivity ranges. However, when it comes to long-haul and heavy-payload use cases, FCEVs have an advantage due to technical considerations. As discussed in the Alternatives Study, FCEVs offer a natural advantage as fleet owners and drivers face minimal changes in daily operations relative to current technology. For BEVs, drivers and fleet operators may need to adapt to new business models, new charging patterns, longer charging times and potentially increased investment in additional vehicles to maintain current business patterns and accommodate decreased payload.

4.2.1.2. Power

In the power sector, hydrogen combustion power plants (supplied by Angeles Link) and longer duration 12-hour battery storage facilities (the electrification alternative for the purpose of this study) were analyzed for a use case where power plants or storage facilities provide extended reliability services to the grid during periods of peak demand. As discussed in the Alternatives Study, Angeles Link is assessed based on a retrofitted hydrogen-fueled combustion plant, while electrification is assessed based on a series of three sequenced 4-hour lithium-ion battery units to enable 12 hours of total duration capability to serve system reliability needs beyond what typical 4-hour duration batteries can provide as shown in Table 8 below.

Lithium-ion batteries are commercially available based on 4- to 8-hour durations and are not typically classified as a long-duration solution; however, the goal of this analysis was to select a technology with reliable cost data and technology maturity that could reasonably illustrate the strengths and weaknesses of an electrification alternative for the power use case. The rationale for choosing a 12-hour battery to provide grid reliability services is detailed in the Appendix section of the Alternatives Study. The assumption of a retrofitted combustion plant is based on the rationale that power plant owners would replace existing gas turbines with hydrogen-capable turbines, in line with Los Angeles Department of Water and Power's (LADWP) decision to retrofit its Scattergood facility.[101]

An LCOE analysis was conducted to compare these alternatives to capture the lifetime capital and operating costs per unit of electricity produced. The LCOE represents the present value of the total capital, operational, and financing costs associated with installing and operating a new or retrofitted generation or storage asset over its economic lifespan. LCOE is widely used by governments, utilities, and independent power producers as it provides a common metric to

[101] https://www.ladwp.com/community/construction-projects/west-la/scattergood-generating-station-units-1-and-2-green-hydrogen-ready-modernization-project.

assess the economic competitiveness of different generation technologies and can also be adapted to assess the economics of storage technologies.

Table 8: Configurations and Cost Metrics for Power

Power Use Case	Alternative	Technology Application	Cost Metric
Low Capacity Factor / Reliability Units	Angeles Link	Hydrogen Turbine (retrofit)[102]	Levelized Cost of Electricity (LCOE) ($/MWh)
	Electrification	12-hr Battery Storage	

Sensitivity ranges in the LCOE analysis reflect the range of uncertainty across the upfront capital and operating costs, fuel/charging costs, and capacity factors which influence the total generation output of the facility. The implications of these sensitivities are discussed in Key Sensitivities (see Section 4.2.1.2.2). Additional details of the LCOE modeling assumptions can be found in Appendix 7.3.2.2.

4.2.1.2.1.Cost Analysis Results

The results from the LCOE analysis show that a retrofitted hydrogen turbine that operates at a lower capacity factor would be more cost-effective when compared to a 12-hour battery storage resource (the rationale for selecting a 12-hour battery for providing long-duration storage requirements is detailed in the Alternatives Study). The high upfront cost of building a battery storage facility designed for a 12-hour duration outweighs the higher hydrogen fuel cost (reflected by the estimated delivered LCOH of Angeles Link) for operating a retrofitted turbine. Detailed assumptions and ranges of capital expenditures, operational costs, applicable incentives, and performance metrics are provided in the Appendix 7.3.2.2. The component breakdown of the LCOE is shown below in Figure 10.

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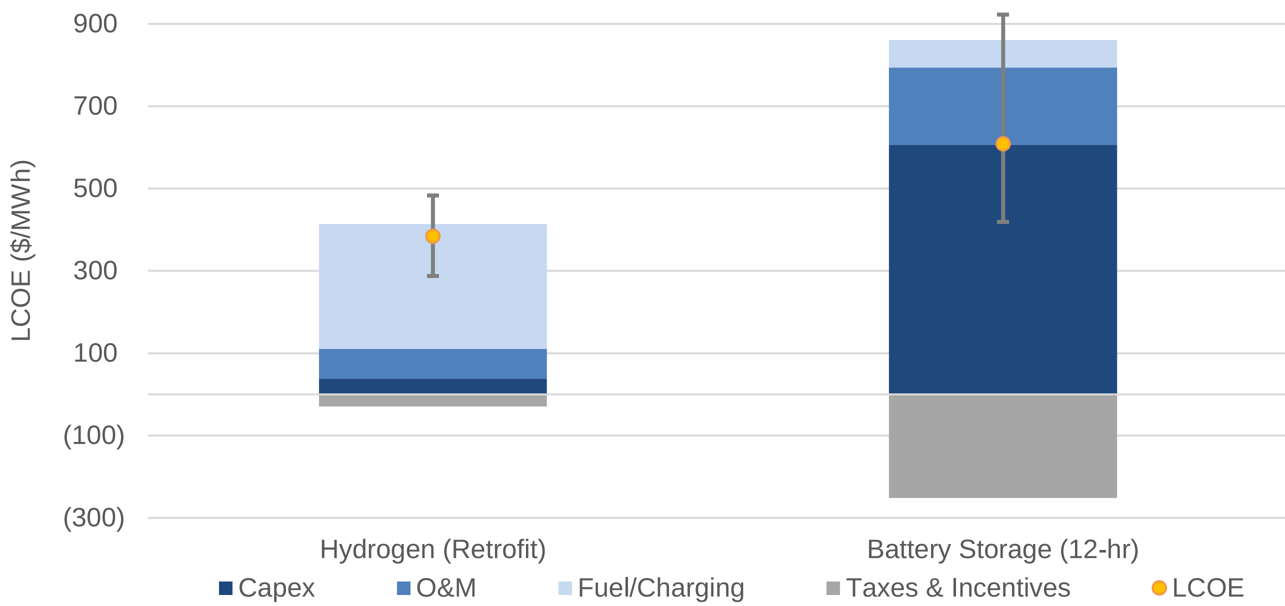
[102] Retrofitted hydrogen turbines involve replacing existing natural gas turbines with hydrogen-capable turbines. This is further detailed in the Alternatives Study.

Figure 10: Cost Effectiveness: Power (Hydrogen and Battery Storage) (2030)



Note: For taxes and incentives, hydrogen power plant retrofits are assumed to be eligible for a 45Y Production Tax Credit (PTC) for the first ten years of the plant's life. Battery storage facilities are assumed to be eligible for a 30% Investment Tax Credit (ITC).

Retrofitted hydrogen combustion turbine: LCOE ranges between $288 - $483 per MWh, primarily driven by the estimation range around fuel costs. This configuration assumes existing gas power plants are retrofitted with 100% clean renewable hydrogen-capable turbines, which minimizes the capital cost compared to a new-build facility. However, feedstock cost (based on the LCOH of Angeles Link) is the primary driver of the levelized cost, making up about 75% of the LCOE.

Battery storage (12-hour): LCOE ranges between $419 - $923 per MWh, primarily driven by the estimation range around battery system capital expenditure (CapEx). Upfront capital costs make up 70% of the LCOE, as the 12-hour battery storage configuration is modeled based on three 4-hour duration stacks, which increases the capital cost of the system to provide longer duration reliability services. A key assumption underlying the modeling of 12-hour battery storage is the effective capacity factor (or the percentage of all hours of a typical year during which the battery is discharging). To ensure an equivalent comparison to a hydrogen peaker plant capable of providing longer duration reliability services, an effective capacity factor (near 10%) was applied to the hypothetical battery configuration. This assumption is indicative of a commercial model in which the battery system would be required to remain available to discharge during longer duration reliability events and thus unable to discharge more frequently to engage in energy arbitrage or other grid services. This is not common practice in the market today and is an indication of why there are few readily available clean energy solutions for longer duration reliability needs of the power system. Additional rationale for choosing a 12-hour battery storage system is detailed in the Alternatives Study.

4.2.1.2.2. Key Sensitivities: Capital Costs and Fuel/Charging Cost

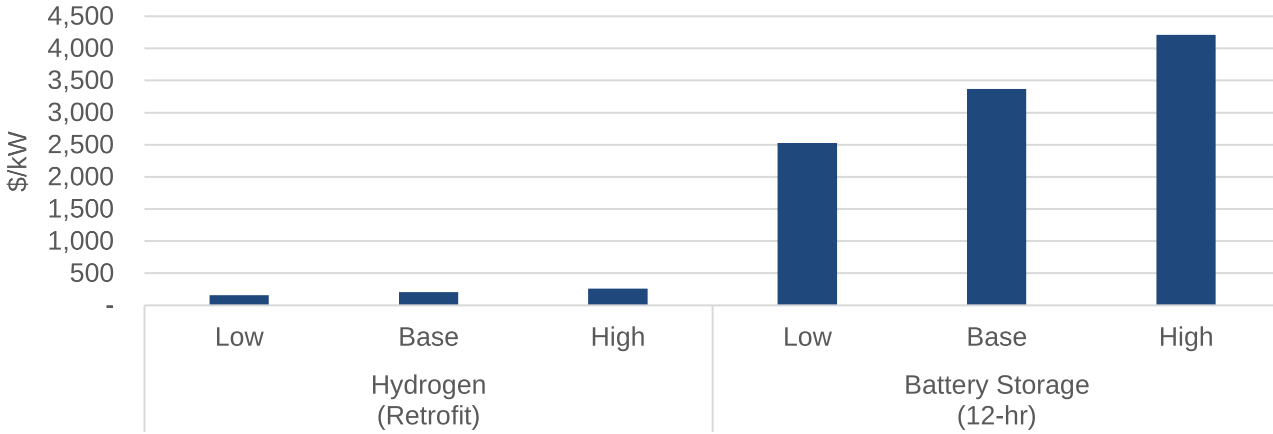
To reflect the potential variability in cost assumptions for different alternatives, as well as to consider the impact of future advancements in battery and hydrogen turbine technology, a sensitivity analysis was performed on the key inputs during the LCOE analysis. Capital expenses and fuel costs were identified as the two main factors influencing the sensitivities.

Capital Cost

The capital cost of the retrofitted hydrogen turbine was derived from a National Petroleum Council (NPC) report,[103] which captured industry consensus on capital expenditures. When considering the installed cost, the capital expenditures for a retrofitted turbine are expected to be less than those for a new-build facility, as the retrofit takes advantage of existing infrastructure. A range has been incorporated to accommodate potential changes in turbine efficiency and design as these retrofitted facilities become operational after 2030.[104]
The capital cost of battery storage is based on estimates for new-build lithium-ion battery facilities (the assumptions for these estimates are detailed further in Appendix 7.3.2.2). A range has also been applied to the battery storage capital cost to account for potential cost variability. The battery capital costs shown in Figure 11 below are high because they reflect the increase in capital costs due to a tripling of a typical 4-hour battery facility to achieve the 12-hour capability.

[103] National Petroleum Council. (2024). https://harnessinghydrogen.npc.org/.
[104] Based on inputs from third-party models and NPC.

Figure 11: Capital Cost of Hydrogen Turbine vs. Battery Storage[105]



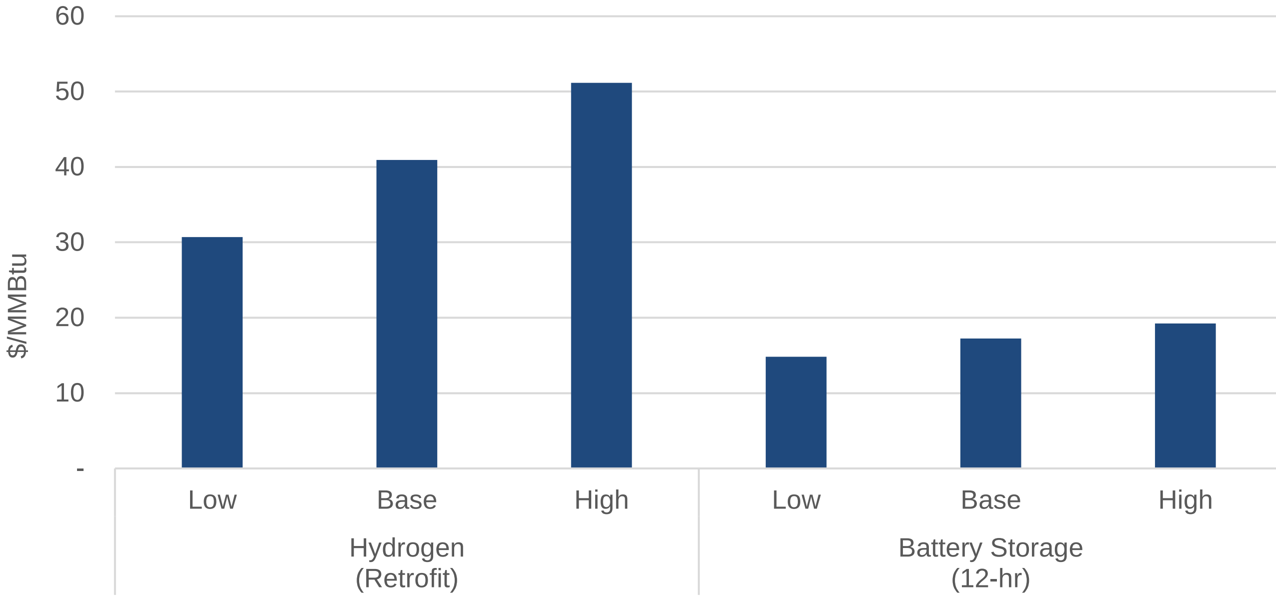
Fuel/Charging Cost

Fuel or charging costs are key in determining the cost-effectiveness of a power plant, as they constitute a significant portion of the operational costs for any facility. For molecular fuels, these costs are largely determined by the production and distribution cost of the fuel and the efficiency of the turbines. For the purpose of this study, the hydrogen fuel cost assumed for hydrogen turbines is the LCOH of Angeles Link. For battery facilities, charging costs are influenced by the generation and distribution costs of electricity, roundtrip efficiency, and the number of discharge cycles. A sensitivity range is applied to both hydrogen fuel delivery costs and electric charging costs as shown in Figure 12.

For hydrogen, this sensitivity considers potential changes in production and delivery costs across the value chain. For the cost of charging battery storage facilities, this sensitivity considers the variability in possible charging sources (i.e., from the grid or from a co-located solar or other renewable facility).

[105] Refer to Appendix 7.3.2.2 for the underlying data assumptions reflected in the Low, Base and High sensitivity cases.

Figure 12: Fuel/Charging Cost of Hydrogen Turbine vs. Battery Storage[106]



4.2.1.2.3.Non-Economic Considerations

As discussed in the Alternatives Study, the increasing share of intermittent wind and solar generation creates challenges for grid reliability, requiring a combination of clean firm generation and LDES. Clean renewable hydrogen can support clean firm generation as well as LDES needs through the development and use of hydrogen storage resources or linepack. Battery storage facilities (4-hour discharge duration resources) are better equipped to address only shorter-duration ramping and grid services. Emerging technologies like compressed air energy storage (CAES) and vanadium redox flow batteries (VRFB) may serve as better candidates for LDES than lithium-ion in the long run, however their adoption is uncertain, as discussed in the Alternatives Study. Unblended clean hydrogen-capable turbines have a technology readiness level (TRL) score of seven, indicating that they are close to commercial operations.[107] Various fuel-flexible hydrogen turbines are under development with Tier 1 original equipment manufacturers (OEMs) and are expected to be commercially available by

[106] Refer to Appendix 7.3.2.2 for the underlying data assumptions reflected in the Low, Base, and High sensitivity cases.
[107] The https://www.iea.org/data-and-statistics/data-tools/etp-clean-energy-technology-guide published by the International Energy Agency. See Appendix in Alternatives Study for additional detail on the TRL scores.

2030. For example, a pilot project in France successfully demonstrated a gas turbine operating with 100% renewable hydrogen.[108]

4.2.1.3. Industrial – Food & Beverage and Cement

In industrial use cases, Angeles Link has the potential to serve the F&B and cement sectors to support the decarbonization of hydrogen-fueled ovens, fryers, and cement kilns. This section compares the hydrogen end-use technology with the electrified equivalent. For the purpose of this study, the cost effectiveness analysis focuses exclusively on the fuel (or electricity) costs associated with operating the equipment and does not consider the capital costs of equipment replacement or other non-fuel operating costs.[109] A direct comparison of fuel and electricity costs on a $/MMBtu basis highlights the costs of switching to the alternative fuels in these industrial use cases. Sensitivity ranges were applied to reflect the range of uncertainty in the cost of fuel and electricity. The implications of these sensitivities are discussed in Key Sensitivities sub-section 4.2.1.3.2. Additional details on the fuel cost modeling assumptions can be found in Appendix 7.3.2.4.

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[108] HYFLEXPOWER Project – https://www.siemens-energy.com/global/en/home/press-releases/hyflexpower-consortium-successfully-operates-a-gas-turbine-with-.html.
[109] The capital costs of equipment replacement are assumed to be similar across hydrogen-fueled and electrically powered equipment in these industries. This was a simplifying assumption made for the purpose of this study given the small volumes of hydrogen demand projected in the Demand Study for the food & beverage and cement sectors.

Table 9: Configurations and Cost Metrics for Cement and Food & Beverage

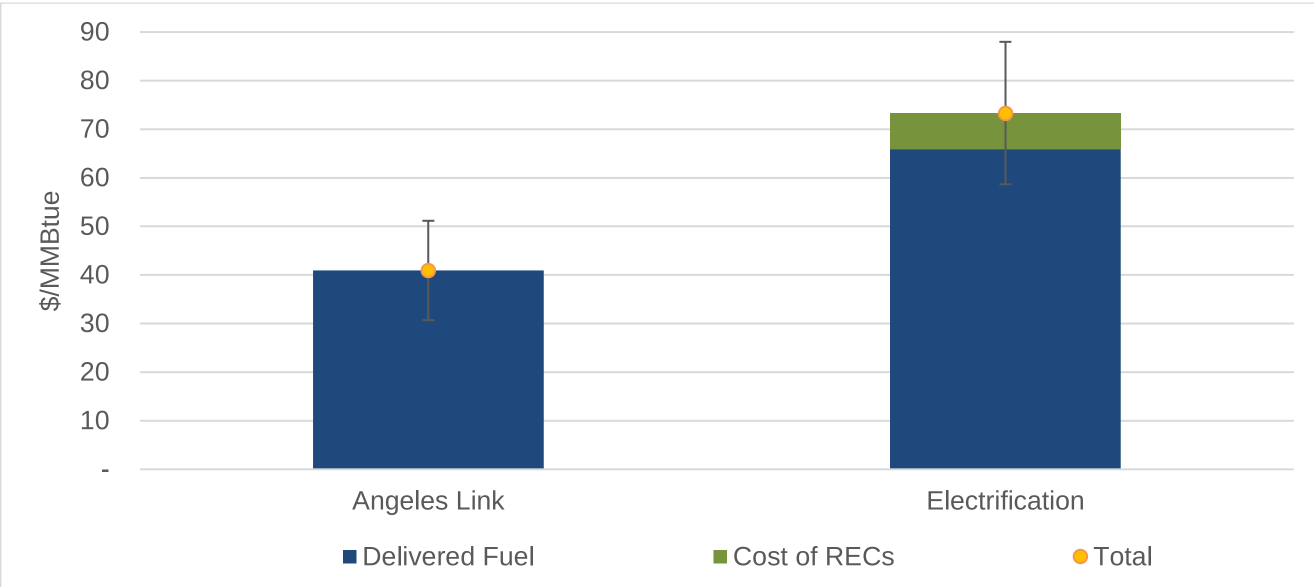
Use Case	Alternative	Technology Application	Cost Metric
Cement High Process Heat	Angeles Link	Hydrogen Kiln	Fuel Cost ($/MMBtu$_e$)[110]
	Electrification	Electric Kiln	
Food & Beverage Low-Medium Process Heat	Angeles Link	Hydrogen Ovens/Fryers	
	Electrification	Electric Ovens/Fryers	

4.2.1.3.1.Cost Analysis Results

The findings indicate that clean renewable hydrogen delivered through Angeles Link serving kilns for cement processing and ovens and fryers for the F&B sector offers a cost-effective solution when compared to electrification. This is driven by high electricity tariffs for industrial customers in California compared to the equivalent cost (on a $/MMBtu basis) of delivered hydrogen. Additional findings from the fuel cost comparison are discussed in Figure 13.

[110] This reflects the LCOH of Angeles Link converted to MMBtu based on the energy value of hydrogen. For electrification, the fuel cost reflects industrial electricity tariffs in the Central and Southern California region converted to MMBtu based on the energy value of electricity.

Figure 13: Cost Effectiveness: Food & Beverage and Cement (Hydrogen and Electrification) (2030)[111]



Angeles Link: The cost of fuel delivered to F&B and cement facilities ranges from $31-$51 per MMBtu, reflecting an estimation range for the delivered cost of hydrogen. The drivers of this delivered fuel cost are discussed in the Delivery Alternatives section (see section 4.1) of this study.

Electrification: The cost of electricity ranges between $59-$88 per MMBtu, reflecting an estimation range for future industrial electricity tariffs. This reflects industrial electricity tariffs in the Central and Southern California region converted to MMBtu based on the energy value of electricity, in addition to the cost of procuring RECs to offset the carbon footprint of grid electricity.

4.2.1.3.2. Key Sensitivities: Fuel Cost

As both F&B and cement are primarily output-based industries, the cost of fuel is a significant driver for the operational costs for the industries as a whole. The efficiency of the equipment that runs on these fuels would determine the overall fuel costs for the facility. The analysis focused exclusively on the unit cost associated with switching fuels to run the applicable

111 As electric kilns, fryers, and ovens consume electricity from the grid, the cost of procuring renewable energy credits (RECs) was added to ensure the emissions profile is clean and comparable to the clean renewable hydrogen delivered by Angeles Link.

equipment in a F&B and cement facility. A sensitivity range is applied to both energy sources to reflect a reasonable range of uncertainty around future costs.

For clean renewable hydrogen, this sensitivity considers potential changes in production and delivery costs across the value chain. For electrification, this sensitivity considers potential changes to the future California generation portfolio as well as T&D investment.

4.2.1.3.3.Non-Economic Considerations

In the F&B sector, electric-powered equipment, including fryers and ovens, are commercially available today. Hydrogen equipment suitable to decarbonize the diverse set of needs for this sector is not as commercially widespread. For low temperature heating applications that would be applicable in F&B equipment like ovens and fryers, hydrogen and electrification both score nine in the International Energy Agency's (IEA) TRL, representing different stages of market uptake in select environments.[112]
In the cement industry, hydrogen and electric kilns are at a similar stage of development with both technologies in pilot stage projects. Both have achieved a rating of five on the TRL scale.[113]

4.2.2. Cost Effectiveness of Angeles Link vs. CCS

Angeles Link was analyzed relative to CCS across the same set of CCS use cases assessed in the Alternatives Study, as detailed below:

- **Power**: Hydrogen-fueled combustion plant vs. natural gas-fueled combustion plant with CCS.
- **Cogeneration**: Hydrogen-fueled cogeneration facility vs. natural gas-fueled cogeneration facility with CCS.
- **Cement**: Hydrogen-fueled kilns vs. natural gas-fueled kilns with CCS.
- **Refineries**: Angeles Link-delivered clean renewable hydrogen for refinery process needs vs. addition of CCS to current unabated hydrogen supply from existing natural gas-fueled steam methane reformers (SMRs).

4.2.2.1. Power and Cogeneration

The power and cogeneration use cases are presented together since the cost-effectiveness considerations are similar. In both sectors, Angeles Link is evaluated based on a retrofitted hydrogen turbine combustion facility (i.e., replacing existing natural gas turbines with turbines capable of running on hydrogen fuel), while CCS is analyzed based on a natural gas plant

[112] IEA TRL Scores.
[113] Ibid.

retrofitted with CCS. Both the power and cogeneration facilities are assumed to run at high capacity factors (detailed in the assumptions in Appendix 7.3.2.2) to serve a baseload-like profile. The costs presented for CCS in this section assume a 90% capture rate, which is compliant with the latest U.S. Environmental Protection Agency (EPA) requirements.[114] An LCOE analysis was then conducted to determine the cost effectiveness of the two alternatives in the power and cogeneration sectors.

Table 10: Configurations and Cost Metrics for Power and Cogeneration

Use Case	Alternative	Technology Application	Cost Metric
High Capacity Factor / Baseload Units	Angeles Link	Hydrogen Turbine (retrofit)	Levelized Cost of Electricity (LCOE) ($/MWh)
	CCS	Gas Turbine with CCS (retrofit)	

The LCOE analysis was performed using third-party models,[115] leveraging market-based asset level and system cost data to compare these alternatives. Any uncertainties in the underlying capital and operating costs, fuel cost, operating metrics, and potential CO_2 transport and sequestration tariffs (applicable only to CCS) were captured in a sensitivity analysis. The implications of these sensitivities are discussed in the Key Sensitivities sub-section. Additional details of the LCOE 62 modeling assumptions can be found in Appendix 7.3.2.2.

4.2.2.1.1.Cost Analysis Results

The results from the LCOE analysis show that a CCS retrofit can be more cost effective compared to a retrofit hydrogen turbine in both power and cogeneration use cases, assuming site suitability for CCS equipment and access to CO_2 transport and sequestration infrastructure.[116] The analysis showed that the higher cost of hydrogen fuel outweighs the higher capital cost associated with installing carbon capture equipment for CCS and the additional cost of CO_2 transport and sequestration. The sensitivity ranges include potential

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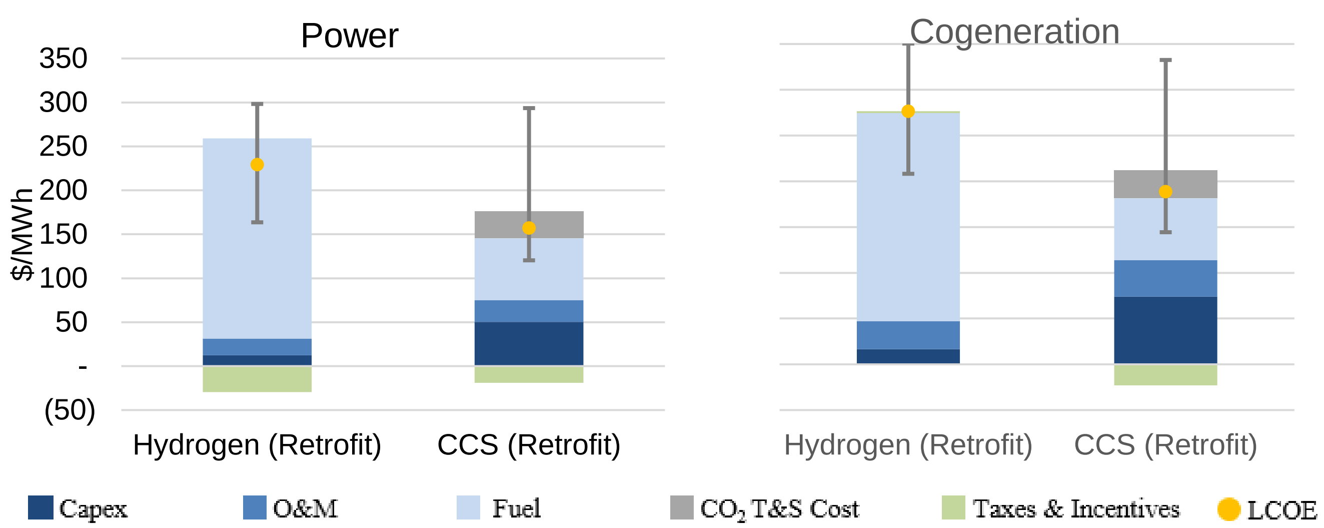
[114] EPA ruling – https://www.epa.gov/system/files/documents/2024-04/cps-111-fact-sheet-standards-and-ria-2024.pdf

[115] Third-party LCOE models.

[116] CCS adoption will be heavily dependent on-site level and regional factors, including geospatial constraints, remaining facility life, and access to CO_2 transport and sequestration infrastructure near point sources, all of which could impact technical feasibility and cost.

variance in the capacity factors for CCS retrofit plants, accounting for the possible additional energy requirements of operating CO_2 capture equipment. Detailed assumptions and sensitivity ranges of inputs are provided in the Appendix 7.3.2.3. The component breakdown of the LCOE across the power and cogeneration sectors is shown below in Figure 14.

Figure 14: Cost Effectiveness: Power & Cogeneration (Hydrogen and CCS) (2030)



Note: "T&S" refers to CO_2 transport and sequestration.

Retrofitted hydrogen combustion turbine: LCOE ranges between $164 - $298 per MWh for the power use case and $208 - $350 per MWh for the cogeneration use case, driven primarily by the range in delivered hydrogen cost. The cost of hydrogen fuel delivered from Angeles Link to operate the turbines is the primary driver of the LCOE, making up about 80% of the total LCOE across both use cases.

CCS retrofit: LCOE ranges between $120 - $293 per MWh for power applications and $144 - $333 per MWh for cogeneration applications. The upfront capital cost and fuel cost are the primary drivers of the LCOE for a CCS plant, with the range driven primarily by variation in potential CO_2 transport and sequestration tariffs faced by end users.

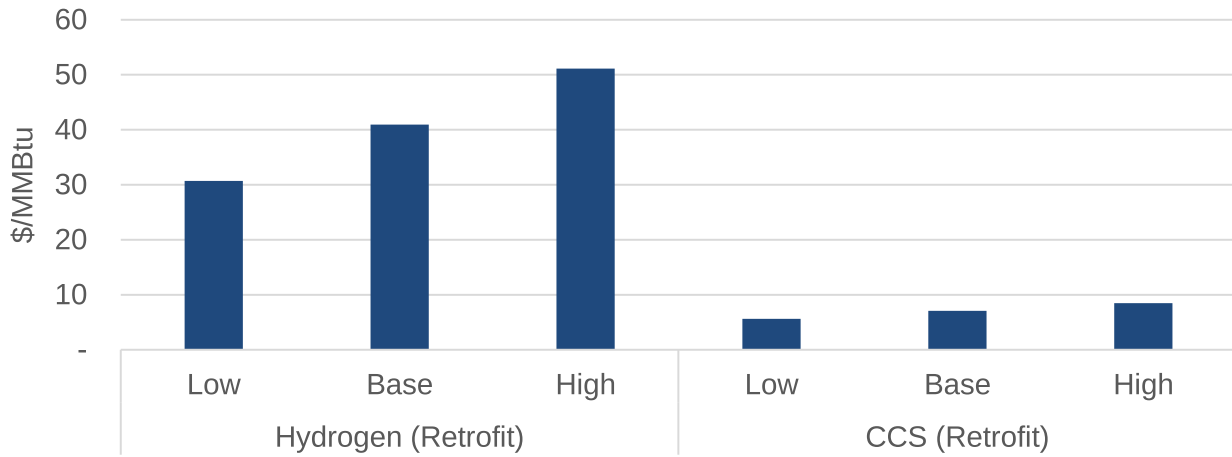
4.2.2.1.2.Key Sensitivities: Fuel Cost and CO_2 Transport & Storage Cost

A series of sensitivity analyses were conducted to account for the uncertainty surrounding the cost assumptions for the alternatives. Two variables were identified as the primary factors influencing the outcome—fuel cost and CO_2 transport and sequestration cost.

Fuel Cost

The cost-effectiveness of a power plant heavily relies on fuel costs, as they make up a substantial portion of the operational expenses for any facility. The costs associated with molecular fuels, such as hydrogen, are influenced by both the expenses of the feedstock and the efficiency of the turbines. A lower efficiency in the turbines results in higher fuel costs, as a larger quantity of feedstock is required to produce the same level of output. The study applied a sensitivity range to the costs of hydrogen and natural gas. The variation in the natural gas cost reflects a range of market prices and potential future industrial natural gas tariffs, while the variation in hydrogen cost reflects an estimation range for the production and delivery costs of clean renewable hydrogen.

Figure 15: Fuel Cost Variation Across Hydrogen and CCS Alternatives in Power and Cogen[117]



Economics of CO_2 Transport and Sequestration

The cost of transporting and storing captured CO_2 from a CCS facility is a key determinant of cost-effectiveness. For this study, transport is assumed to be provided by a CO_2 pipeline system, with storage provided by underground CO_2 reservoirs. The cost of CO_2 transport and sequestration services for power generation or cogeneration facilities is determined by the capital and operating costs associated with the assets, as well as integrating point source CO_2 capture from multiple end-use users. Some of the power and cogeneration facilities in Central and Southern California are situated near industrial clusters, which could support infrastructure development for a hypothetical CO_2 transport and sequestration system.

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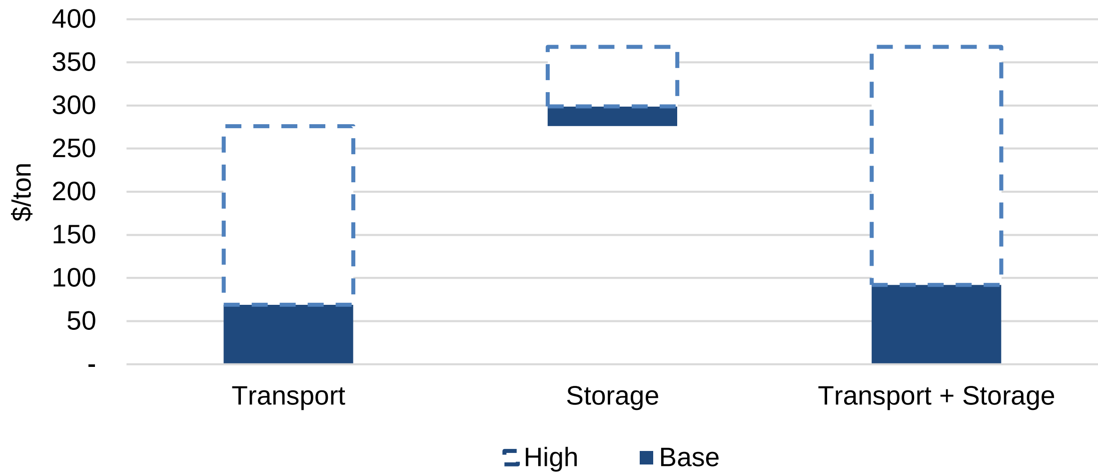
[117] Refer to Appendix 7.3.2.2 for the underlying data assumptions reflected in the Low, Base and High sensitivity cases.

In this analysis, the CCS infrastructure was assumed to be fully utilized in the base case, with a higher cost sensitivity case representing lower utilization of the system. Figure 16 below shows the variation in CO_2 transport and sequestration costs.

Figure 16: Variations in CO_2 Transport and Sequestration Costs for CCS Facilities[118]



4.2.2.1.3.Non-Economic Considerations

CCS provides a potential pathway to achieve the State's carbon-neutral targets by 2045, but it is reliant on sufficient scale and integration of supporting infrastructure to collect, transport, and sequester CO_2. In the power and cogeneration sectors, CCS can be cost-effective, but adoption is expected to be reliant on site-level and regional factors that are beyond the scope of this study, including geospatial constraints, remaining facility life, and access to CO_2 transport and sequestration infrastructure near point sources, all of which could impact technical feasibility and cost.

4.2.2.2. Industrial – Cement

In the cement sector, hydrogen delivered by Angeles Link and CCS are assessed primarily for the decarbonization of the high heat needs for processing cement. As discussed in the Demand study, SB596 specifically mandates the decarbonization of the cement industry in California. Both CCS and hydrogen can play a role in supporting the goals of this legislation. As discussed in the Alternatives Study, CCS has the potential to address a broader range of

118 The solid bars represent the base case or expected costs for CO_2 transport and sequestration. The dashed lines show how the costs of transporting and storing CO_2 could increase under lower integration scenarios.

emissions sources within a cement facility — including clinker production[119] — in addition to the kiln. However, this analysis focused on the cost of fuel associated with cement kilns. In the cement sector, hydrogen-fueled kilns (with hydrogen supplied by Angeles Link) are compared to gas kilns with CCS equipment added (the CCS alternative). The cost effectiveness analysis focuses exclusively on the fuel costs associated with operating the equipment and does not consider the capital costs of equipment replacement or other non-fuel operating costs other than an assumed CO_2 transport and sequestration tariff added to fuel costs for the CCS alternative[120]. A direct comparison of fuel costs on a $/MMBtu basis was carried out, with sensitivity ranges added to reflect the range of uncertainty in the cost of fuel and the cost of carbon transport and sequestration. The implications of these sensitivities are discussed in the Key Sensitivities sub-section below. Additional details on the modeling assumptions can be found in the Appendix 7.3.2.

Table 11: Configurations and Cost Metrics for Cement

Use Case	Alternative	Technology Application	Cost Metric
Cement High Process Heat	Angeles Link	Hydrogen Kiln	Fuel Cost ($/MMBtu$_e$)
	CCS	Gas Kiln with CCS	

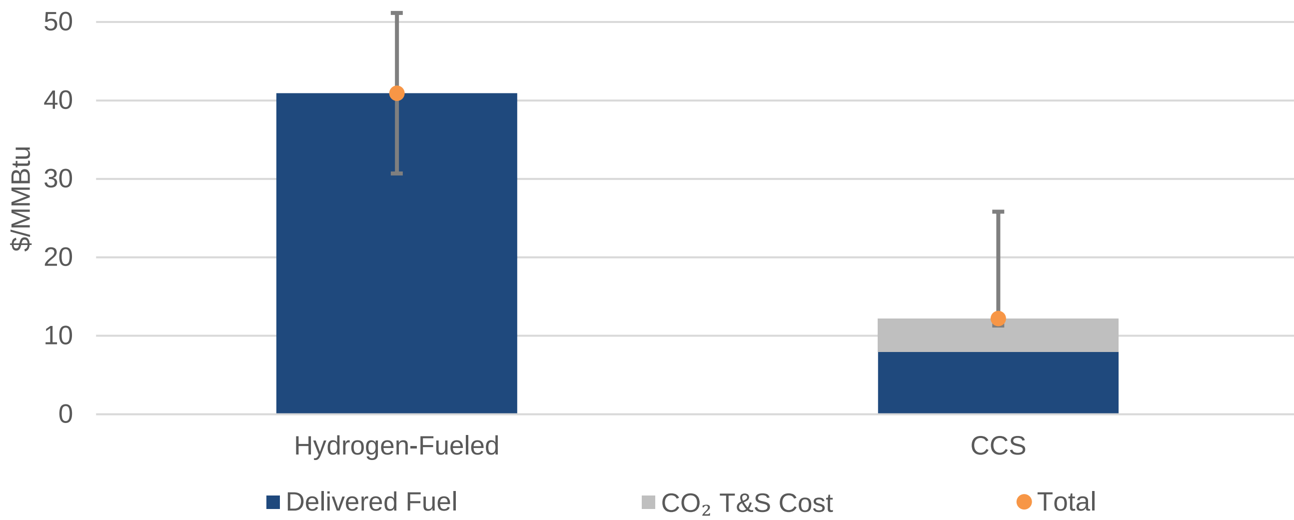
4.2.2.2.1.Cost Analysis Results

The analysis reveals a gap in cost parity when comparing incumbent fuels such as natural gas with clean renewable hydrogen supplied by Angeles Link. The cost-effectiveness of CCS is driven by this fuel cost disparity, provided that the site is suitable for CCS equipment and there is sufficient access to CO_2 transport and sequestration infrastructure. The following additional findings are presented and discussed in Figure 17.

[119] Clinker is a hard nodular material caused when raw materials such as limestone, chalk, shale, clay and sand react at high temperatures. Source: https://www.epa.gov/sites/default/files/2015-12/documents/cement.pdf.

[120] For the cement sector analysis, the capital costs associated with hydrogen kiln retrofits and CO_2 capture equipment were not considered, nor were the costs of incremental energy to power the capture equipment. It is possible that these considerations could impact the relative cost effectiveness of clean renewable hydrogen and CCS in the cement sector.

Figure 17: Cost Effectiveness: Cement (Hydrogen and CCS) (2030)



Note: “T&S” refers to CO_2 transport and sequestration.

Angeles Link: The cost of fuel delivered to cement facilities ranges from $29 - $49 per MMBtu. This reflects the delivered cost of hydrogen from Angeles Link.

CCS: The cost ranges between $11 - $26 per MMBtu. This reflects the cost of natural gas delivered to industrial users in Central and Southern California, measured by prices at SoCal Citygate,[121] the major natural gas price hub in Southern California, in addition to the cost of transport and sequestration of captured CO_2 from the cement facility.

4.2.2.2.2.Key Sensitivities: Fuel Cost and CO_2 Transport and Sequestration Costs

The cost of alternatives for a cement facility is highly dependent on both fuel cost and the cost of CO_2 transport and sequestration infrastructure. The study applied a sensitivity range to the costs of hydrogen and natural gas. The variation in the natural gas price reflects a range of market prices and potential future industrial natural gas tariffs, while the variation in hydrogen cost reflects an estimation range for the production and delivery costs of clean renewable hydrogen. A multiplier was also added to CO_2 transport and sequestration infrastructure costs to reflect uncertainties in the cost and utilization of the infrastructure.

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[121] Forecasted natural gas prices at SoCal Citygate were derived from Wood Mackenzie North America Gas Service.

4.2.2.2.3.Non-Economic Considerations

Based on the criteria evaluated in the Alternatives Study, both Angeles Link and CCS offer potentially viable solutions for the cement industry. While both technologies are currently being demonstrated in pilot projects[122] CCS has a scaling advantage of addressing the wider cement emissions stack to help advance SB 596 goals for California to enable decarbonization of the cement sector by 2045.[123] Adoption of CCS in the cement sector will depend on factors such as the availability of space for additional equipment within the plant boundary, access to supporting transport and sequestration infrastructure, and proximity to other industrial clusters for efficient integration and lower cost of transport and sequestration infrastructure.

4.2.2.3. Industrial – Refineries

The allocation of capital towards decarbonization efforts in the refinery sector will depend on the future demand for refinery products. Currently, the refineries operating in Central and Southern California primarily use unabated hydrogen for hydrocracking and sulphur removal processes (made from natural gas using SMRs) that does not meet the definition of clean renewable hydrogen. Available decarbonization pathways for this process hydrogen include clean renewable hydrogen (which could be supplied by Angeles Link) and the conversion of current unabated hydrogen to abated hydrogen with CO_2 capture (by adding CCS to existing SMR supply). In this study, clean renewable hydrogen (supplied by Angeles Link) is compared to the addition of CCS infrastructure to existing unabated hydrogen supply. A direct comparison of LCOH was carried out and sensitivity ranges were added to reflect uncertainties in LCOH and in the cost of CO_2 transport and sequestration infrastructure. The implications of these sensitivities are discussed in the Key Sensitivities sub-section 4.2.2.3.2. Additional details of the modeling assumptions can be found in the Appendix 7.3.2.6.

Table 12: Configurations and Cost Metrics for Refineries

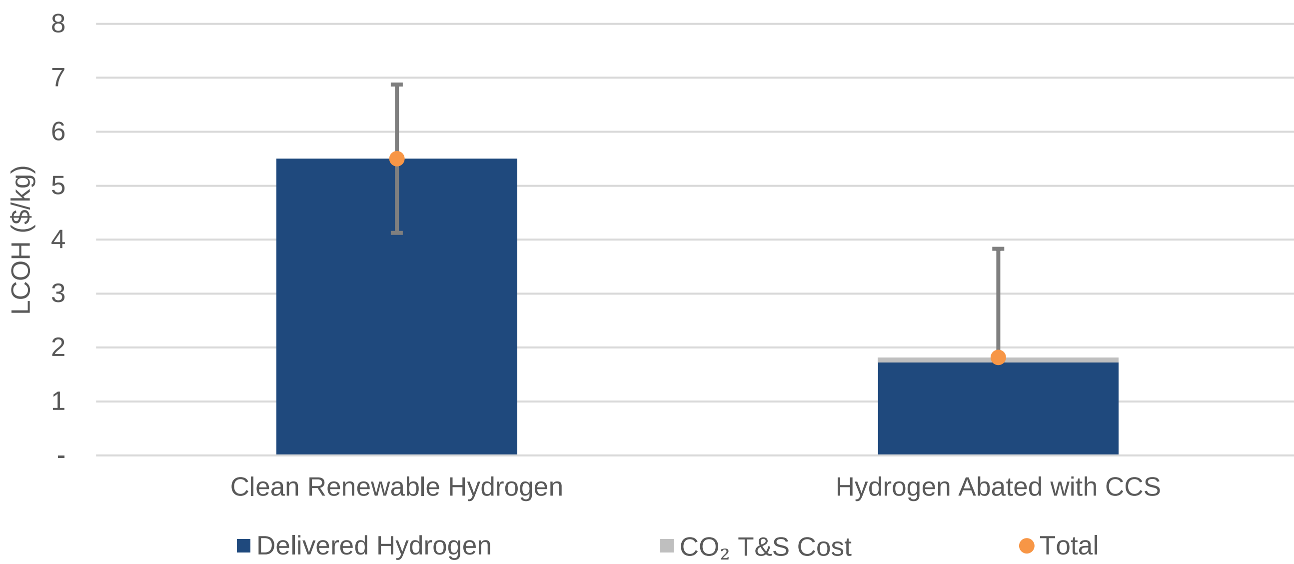
Refinery Use Case	Alternative	Technology Application	Cost Metric
Process Hydrogen	Angeles Link	Clean Renewable Hydrogen	LCOH ($/kg)
	CCS	Hydrogen Abated with Carbon Capture	

[122] Demonstration projects, TRL 5-7. The https://www.iea.org/data-and-statistics/data-tools/etp-clean-energy-technology-guide published by the International Energy Agency.
[123] https://ww2.arb.ca.gov/our-work/programs/net-zero-emissions-strategy-cement-sector.

4.2.2.3.1. Cost Analysis Results

The analysis showed that the addition of CCS to existing unabated hydrogen supply is likely more cost effective for refinery hydrogen compared to clean renewable hydrogen delivered from Angeles Link, assuming site suitability for the addition of CCS equipment and access to CO_2 transport and sequestration infrastructure. Additional findings are discussed below:

Figure 18: Cost Effectiveness: Refineries (Clean Renewable Hydrogen and CCS) (2030)



Note: “T&S” refers to CO_2 transport and sequestration. Delivered hydrogen for the CCS alternative includes the cost of capture equipment.

Angeles Link: The cost of hydrogen delivered to refineries ranges from $3.9 - $6.6 per kg. This reflects the LCOH from Angeles Link.

CCS: The cost of hydrogen delivered to refineries ranges between $1.8 - $3.8 per kg. This reflects the input cost of natural gas delivered to near-site SMRs, measured by prices at SoCal Citygate,[124] in addition to the cost of transport and sequestration of captured CO_2 from the refinery facility.

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[124] Citygate is a point or a measuring station at where a gas utility receives gas from a natural gas pipeline company or transmission system. Source: https://www.eia.gov/dnav/ng/TblDefs/ng_pri_sum_tbldef2.asp.

4.2.2.3.2. Key Sensitivities: Fuel Cost and CO_2 Transport and Sequestration Costs

Like cement, the LCOH analysis for refinery hydrogen is sensitive to both fuel cost and the cost of CO_2 transport and sequestration infrastructure. The study applied a sensitivity range to the costs of hydrogen and natural gas. The variation in the natural gas price reflects a range of market prices and potential future industrial natural gas tariffs, while the variation in hydrogen cost reflects an estimation range for the production and delivery costs of clean renewable hydrogen. A multiplier was also added to CO_2 transport and sequestration infrastructure costs to reflect uncertainties in the cost and utilization of the infrastructure.

4.2.2.3.3. Non-Economic Considerations

Adding CCS to existing unabated hydrogen supply could offer a potential decarbonization solution for the refinery sector. It allows for the capture of point source CO_2 within the facility, and refineries offer the necessary scale to make use of a larger CO_2 transport and sequestration infrastructure. Nevertheless, every refinery may adopt a unique strategy for reducing CO_2 emissions in their hydrogen supply to comply with California's decarbonization goals. The viability of CCS in some refineries may be challenging due to geospatial limitations, the remaining operational life, or the economic performance of the facility. CCS retrofits for refinery process use versus the use of clean renewable hydrogen will also be influenced by the availability of CO_2 transport and sequestration infrastructure and enabling state policy.

4.2.3. Cross-Sector Takeaways for Non-Hydrogen Alternatives

This study found that clean renewable hydrogen delivered by Angeles Link is cost effective relative to electrification for Phase 1 purposes. While CCS can be more cost effective than Angeles Link in some use cases, it requires specific conditions for adoption, including access to CO_2 transport and sequestration infrastructure, site-level capacity for CO_2 capture equipment, and end user proximity to wider industrial clusters to drive scale.

- In the **mobility** sector, FCEVs (supplied by Angeles Link) were found to be cost-effective relative to BEVs (the electrification alternative) for long-haul use cases with en-route refueling needs like Class 8 sleeper cabs and transit buses. Depending on fuel and charging costs, FCEVs can also be cost-effective for other heavy-duty use cases like Class 8 drayage and day cabs. CCS is not a technically viable alternative that could be deployed at scale to capture tailpipe emissions for the mobility sector (which accounts for approximately 40% of estimated hydrogen demand by 2045 according to the Demand Study).
- In the **power** sector, hydrogen combustion power plants (with hydrogen supplied by Angeles Link) were found to be cost-effective relative to 12-hour lithium-ion battery energy storage facilities (the electrification alternative) for lower capacity factor reliability

use cases (peakers). Both hydrogen combustion turbines (with hydrogen supplied by Angeles Link) and CCS (added to gas power plants) can be cost-effective for higher capacity factor use cases (baseload), although CCS adoption is reliant on site-level capacity for CO_2 capture equipment and access to CO_2 transport and sequestration infrastructure.

- In **industrial** sectors, clean renewable hydrogen delivered by Angeles Link was found to be cost-effective relative to electrification for medium- and high-heat industrial needs due to high industrial electricity tariffs in California. CCS was generally found to be more cost effective than Angeles Link for cogeneration, refinery, and cement applications,[125] although CCS adoption is reliant on site-level capacity for CO_2 capture equipment and access to CO_2 transport and sequestration infrastructure, among many other variables.

[125] Particularly in the cement sector, CCS is well-positioned to support California's decarbonization goals set out in SB 596 due to its ability to address the full scope of cement facility emissions.

5. Stakeholder Comments

SoCalGas presented opportunities for the PAG and CBOSG to provide feedback at four key milestones in the course of conducting this study: (1) the draft description of the Scope of Work, (2) the draft Technical Approach, (3) Preliminary Findings and Data, and (4) the Draft Report. These milestones were selected because they are critical points at which relevant feedback can meaningfully influence the study.

Table 13: Key Milestone Dates

Milestone	Date Provided to PAG/CBOSG	Comment Due Date	Responses to Comments in Quarterly Report
1. Draft Scope of Work	July 6, 2023	July 31, 2023	Q3 2023
2. Draft Technical Approach	September 7, 2023	November 2, 2023	Q4 2023
3. Preliminary Findings and Data	May 21, 2024	June 4, 2024	Q2 2024
4. Draft Report	July 26, 2024	September 6, 2024	Q3 2024

Feedback provided at the PAG/CBOSG meetings is memorialized in the transcripts of the meeting. Written feedback received is included in the quarterly reports, along with responses. Meeting transcripts are also included in the quarterly reports. The quarterly reports are submitted to the CPUC and are published on SoCalGas's website.[126]

Feedback was incorporated as applicable at each milestone throughout the progression of the study. Some feedback was not incorporated for various reasons including feedback that was outside the scope of the Phase 1 Decision or feasibility study and feedback that may be anticipated to be addressed in future phases.

Key feedback that was incorporated through the development of the Cost Effectiveness Study is summarized in the table below.

Table 14: Summary of Incorporation of Stakeholder Feedback

Stakeholder Feedback

[126] https://www.socalgas.com/sustainability/hydrogen/angeles-link

Thematic Comments from PAG/CBOSG Members	Incorporation of and Response to Feedback
<u>Retail (Commodity Price of Hydrogen)</u> Commenters requested consideration of the retail (commodity) price of hydrogen.	Footnote 24 has been added noting that the Cost Effectiveness Study assessed the levelized cost of hydrogen to ascertain the total delivered cost (including production, transport, storage, and delivery).[127] As discussed in Global Response 1 in the Q1 2024 Angeles Link quarterly report, the study was not intended to address the retail (commodity) price of hydrogen, which is driven by costs for most major energy commodities and is also influenced by market-based supply and demand dynamics. Physical delivery and storage infrastructure has also been found to play a critical role in driving convergence between commodity costs and market prices.[128]
<u>Total Investment Cost of Angeles Link</u> Commenters requested information about the total investment cost required to build Angeles Link	Footnote 24 has been added to clarify that this study does not address total investment cost. Please refer to the Design Study, Section 6 (Cost Estimates), which includes a high-level cost estimate for constructing potential conceptual Angeles Link configurations.[129] A more detailed assessment of Angeles Link construction costs

[127] For Angeles Link and delivery alternatives, delivery corresponds to hydrogen provision via Angeles Link Central as defined by the Design Study. See Appendix 7.3.1.5.

[128] Current hydrogen retail pricing in the California market is specific to hydrogen delivered via gaseous and liquid trucks in relatively small quantities for consumption primarily in the passenger FCEV market. With an anticipated increase in clean renewable hydrogen supply and connective infrastructure, it is expected that the costs of hydrogen on a delivered basis (inclusive of production, transmission, storage, and delivery, as well as additional overhead costs not considered within the scope of this study) will play a significant role as a price setting mechanism for clean renewable hydrogen. As discussed in the more detailed responses to comments in the Q1 2024 Angeles Link quarterly report, the study was not intended to address the retail (commodity) price of hydrogen, which is driven by costs for most major energy commodities and is also influenced by market-based supply and demand dynamics.

[129] Please refer to Table 17 (Design Study).

	will be performed in future phases of Angeles Link planning. For purposes of evaluating the cost effectiveness of various hydrogen delivery alternatives in this Cost Effectiveness Study, SoCalGas leveraged the LCOH methodology to evaluate cost effectiveness, which includes the lifetime asset costs associated with hydrogen production, transport, storage, and delivery.
<u>Underlying Assumptions</u> A commenter asked SoCalGas to provide the underlying input assumptions informing the preliminary findings.	Consistent with this stakeholder feedback, additional details were added to Section 3 (Study Methodology Overview) and Section 7 (Appendix) of this report summarizing the key techno-economic input assumptions and considerations informing the cost effectiveness evaluation.
<u>Electric Transmission System</u> A commenter requested evaluation of a High Voltage Direct Current (HVDC) electric transmission system as a potential alternative to support in-basin hydrogen production.	In response to this stakeholder feedback, Appendix 7.5.2 was added to this study, which discusses the potential role of a HVDC system. As described therein, electricity can be transmitted via a HVDC system instead of a High Voltage Alternating Current (HVAC) transmission system. For the purpose of this study, the T&D with in-basin hydrogen production alternative selected a 500kV AC transmission system to enable system and operational compatibility with California's predominantly HVAC electric grid system and with the intent to support the system's reliability and resiliency requirements.
<u>Underground Storage</u> Some commenters indicated that the Study should use only above ground hydrogen storage options, until underground options are proven.	Underground hydrogen storage solutions in depleted oil and gas reservoirs or porous rock formations are currently undergoing various stages of development and testing worldwide. These solutions have the potential to achieve commercial viability in the long term as the demand for hydrogen grows over time. RAG Austria, the largest energy storage company in Austria and a key operator of gas storage facilities in Europe, launched the "Underground

	Sun Storage 2030" project—a field trial to assess the viability of storing unblended hydrogen produced from solar and wind energy in existing natural gas reservoirs. The Underground Sun Storage project has demonstrated the injection and withdrawal of hydrogen.[130] HyStorage, a project by Uniper SE in Germany, has achieved a successful withdrawal of 90% hydrogen following its injection into porous rock formations.[131] This process did not adversely affect the geological reservoir performance, and material testing indicated no significant impact from hydrogen corrosion. The California Energy Commission (CEC) recently awarded Lawrence Berkeley National Laboratory (LBNL) funding for a project that will evaluate the technical and economic feasibility of using existing underground gas storage facilities to store clean renewable hydrogen in California.[132] The project will study underground gas storage facilities in California for their potential to store clean renewable hydrogen, and will estimate levelized costs of hydrogen storage, levelized total capital costs, and operations and maintenance costs. In response to this stakeholder feedback and considering the ongoing stages of development for underground storage solutions, the note for Figure 2 in Section 1.3.1 has been updated to reflect that above ground hydrogen storage could be potentially used in the initial phase of demand growth for hydrogen, particularly at a smaller scale. As the hydrogen economy matures and scales over the long term, commercially advanced underground options may provide dependable large-scale hydrogen storage solutions. In addition, even if above ground

[130] https://www.uss-2030.at/en/news/detail/article/first-withdrawal-phase-has-started.html
[131] https://www.uniper.energy/news/hystorage-first-test-phase-successful--hydrogen-extracted-again-after-injection-into-porous-rock
[132] See GFO-23-503 - Feasibility of Underground Hydrogen Storage in California

	storage is assumed to be the main medium of storage, Angeles Link remains the lowest cost option when evaluated against alternative options.
<u>Purification Costs</u> A commenter requested consideration of the needs/costs for purification of hydrogen for hydrogen refueling stations.	Footnote 30 was added to Section 1.2 Study Approach to answer this response. The scope of the Cost Effectiveness analysis for Angeles Link and hydrogen delivery alternatives is inclusive of all significant costs from production to the customer gate as appropriate for a phase 1 feasibility study. For all delivery alternatives, hydrogen production occurs via PEM electrolyzers that produce hydrogen at a purity of 99.999%. This pure hydrogen is then delivered via the Angeles Link system or alternatives to heavy-duty truck refueling stations, major demand centers and/or a customer gate. For the Angeles Link system, delivery is expected to occur at high pressures and without blending, which reduces the risk of contamination. In the case of hydrogen volumes stored underground, the cost assessment included a Pressure Swing Adsorption (PSA) system to ensure purity in the Angeles Link System. Therefore, it is assumed that no additional significant investments in purification are required. The comparison of hydrogen alternatives for heavy-duty transportation applications includes additional costs to reflect dispensing and distribution expenses. Dispensing costs do not consider any additional purification. In future phases of design, as specific end-use requirements are established with customers, it may be necessary to consider purification processes at different stages of the Angeles Link system and to implement quality control measures to ensure that the hydrogen delivered meets purity standards for specific end users.

6. Future Considerations

The Cost Effectiveness Study as part of Phase 1 was intended to determine a methodology to measure cost effectiveness and evaluate the cost effectiveness of Angeles Link against the alternatives.

For future phases of Angeles Link, and in alignment with expected DOE requirements, a Techno Economic Analysis (TEA) may be conducted for Angeles Link. The TEA will build upon the Phase 1 results to estimate the expected levelized cost of clean renewable hydrogen delivered by Angeles Link. The TEA would be refined as more study results, performance data, and cost estimates become available. The analysis may leverage proprietary and published data, existing DOE tools, estimates or quotes from industry suppliers, and previous operational experience, as needed. This analysis would also likely define expected values of key parameters relevant to future Angeles Link operations, including expected expenditures, tax credits, operating costs, and useful life of the asset(s).

Additionally, integrating Angeles Link to support power generation (and more broadly the electric grid) requires careful consideration of the electric infrastructure, transmission capacity, interconnections, and other grid operational requirements. Hence, future phases may evaluate the role of Angeles Link to support electric system reliability and resiliency. Electric grid integration with hydrogen would support firm dispatchable power, storage, and load balancing needs and would necessitate the need for power systems modeling to evaluate system resiliency and reliability under loss of load expectations (LOLE).

7. Appendix

7.1. Formulas & Calculation Frameworks

7.1.1. LCOH Calculation Framework

LCOH Formula

$$LCOH_{\substack{Post-Tax,\\ Levered}} = \frac{\sum_{i=1}^{T} \frac{(Opex^i + Capex_L^i + Interest^i + Principal^i)}{(1+r)^i}}{\sum_{i=1}^{T} v^i \left(\frac{1+\inf}{1+r}\right)^i}$$

Parameter	Description
OpEx	Operating Expenses
CapEx	Capital Expenses
DTS	Depreciation Tax Shield
L	Levered
T	Total years of Project Lifetime
Inf	Rate of Inflation (%)
r	Discount Rate (%) (required rate of return)
v	Volume of Hydrogen
Interest	Interest Loan Payments
Principal	Principal Loan Payment
i	Time, assumes each year of the operational or economic life of the relevant hydrogen infrastructure
∑	Mathematical shorthand notation to indicate the sum of a number of similar terms, in this case the sum of all years of the operational or economic life of the relevant hydrogen infrastructure

LCOH figures represent the cost for new-build projects:

- Uses volumes of selected routes
- Accounts for losses across the value chain
- Assumes tax incentives (PTC) and tax shields as applicable

7.1.2. LCOE Calculation Framework

$$LCOE = \frac{(CAPEX - \sum_1^n \frac{DEP}{(1+r)^n} \times TR + \sum_1^n \frac{LP}{(1+r)^n} - \sum_1^n \frac{INT}{(1+r)^n} \times TR + \sum_1^n \frac{AO}{(1+r)^n} \times (1-TR) + \sum_1^n \frac{Fuel\ Cost}{(1+r)^n} \times (1-TR))}{\sum_1^n \frac{Initial\ MWh \times (1-Degradation)^n}{(1+r)^n}}$$

Parameter	**Description**
CapEx	Capital Expenses
∑	Sum
n	Life of asset in years
DEP	Depreciation
r	Discount Rate
TR	Tax Rate
LP	Loan Payment
INT	Interest
AO	Annual operation cost including operation and maintenance cost or other taxes such as carbon tax
Fuel Cost	Cost of fuel
Degradation	System degradation rate

Table 15: LCOE Components

LCOE Category	Included Parameters	Key Notes
Capital Costs	• Includes construction, equipment, land, engineering, management, and related capital costs • Finance costs reflect after-tax equity Internal Rate of Return (IRR) hurdle rates	• Thermal generation CapEx generally provided as "overnight" costs: generation, Balance of Plant (BOP), development and interconnection costs • T&D infrastructure is not in scope
Operations and Maintenance	Ongoing costs to run the power station, including equipment and site maintenance, salaries and staff, management, and sales	• Fixed Operations and Maintenance (O&M) includes both scheduled and unscheduled maintenance
Fuel and Emissions Cost	The delivered cost of feedstock for power plants based on price outlooks over the project lifetime[133]	• No national carbon tax assumed • Delivered cost of hydrogen reflects Angeles Link LCOH
Taxes, Fees, and Incentives	May include incentives, land, regulatory, corporate, carbon, value-added or other taxes, or fees required or provided by law	• 45V Production Tax Credit (PTC) is incorporated into the Angeles Link delivered LCOH • Investment Tax Credit (ITC) is incorporated as a reduction in capital cost for battery storage • 45Q tax credit for carbon sequestration is incorporated as a reduction in operating costs for CCS facility owners

7.1.3. TCO Calculation Framework

$$TCO = \frac{IPC + M\&R + Ops + Fuel + Emissions + Taxes + Subsidies}{VMT}$$

[133] Project lifetime ranges between 20-40 years depending on the technology being analyzed. See Appendix 7.3.2.2.

Parameter	Description
IPC	Initial Purchase Cost
M&R	Maintenance and Repairs
Ops	Operations Cost
Fuel	Fuel Cost
Emissions	Emissions cost
VMT	Vehicle Miles Traveled

Table 16: TCO Components

TCO Category	Included Parameters	Key Notes
Initial Purchase Cost	Reflects the MSRP for transit buses and Class 8 trucks based on a fuel economy and depreciation schedule present in commercial vehicles today	Assumes the vehicle is bought outright and not financed
Maintenance and Repairs	Ongoing costs to run the vehicle, including equipment maintenance and servicing	Includes both scheduled and unscheduled maintenance
Operations	Includes labor, dwell time, and payload losses	Reflects vehicle class-specific operational characteristics
Fuel Cost	The delivered cost of hydrogen or electricity to the refueling or charging station	• Hydrogen cost reflects the Angeles Link LCOH, plus the cost of distribution and the refueling station • Electricity cost reflects California retail tariffs for charging stations, plus the cost of the charging station itself and a retail markup
Taxes and Subsidies	• Includes sales, excise, and other taxes or fees required by law • Subsidies reflect all relevant state and federal incentives	• Subsidies reflect purchase and any applicable fuel incentives, including Low Carbon Fuel Standard (LCFS)

7.2. Angeles Link Scenario Configurations and Alternatives Descriptions

7.2.1. Scenario Configurations for Angeles Link

Table 17: Angeles Link Configurations Assumptions by Scenario[134]

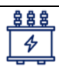
Scenario	Map	Throughput	Production (mtpa)			Storage	
			SJV	Lancaster	Blythe	Depleted Oil/Gas Fields	Salt Caverns
1		0.5 Mtpa	0.5			✓	
2		0.5 Mtpa		0.5		✓	
3		0.5 Mtpa			0.5		✓
4		1.0 Mtpa	0.5	0.5		✓	
5		1.0 Mtpa		0.5	0.5	✓	✓
6		1.0 Mtpa	0.5		0.5	✓	✓
7		1.5 Mtpa	0.75	0.75		✓	
8		1.5 Mtpa	0.5	0.5	0.5	✓	✓

[134] The Production Scenarios as defined Design Study. For additional detail on the scenarios, refer to the Design Study.

7.2.2. Description of Delivery Alternatives

As detailed in Sections 3, a core principle of the analysis was the consistent application of key project parameters across all the Delivery Alternatives, including a common hydrogen production configuration, end-user delivery system, system throughput expectations (hydrogen volumes), demand profile, and potential storage needs. The scope configurations were defined for the delivery alternatives to align with the scale, production locations and storage sites for Angeles Link Scenario 7 to the extent possible. The following sections describe the scope configuration assumptions for each delivery alternative. Table 18 provides definitions for the iconography used as a part of the diagrams and tables included for each alternative definition.

Table 18: Iconography of Infrastructure & Peripherals

Icon	Icon Name Infrastructure & Peripherals
	**Solar power:** *Solar panel arrays, power inverters*
	**Water for electrolysis:** *Water source, water treatment facility, water supply infrastructure*
	**Power transmission and distribution:** *High-voltage transmission lines, electrical grid infrastructure*
	**Substation:** *Transformers, control room, fencing and security, electric connections DC-AC inverters*
	**High, mid, low hydrogen production:** *Electrolyzers, H_2 purification and compression units, utility connections for water and power*
• • •	**Subscale hydrogen production:** *Electrolyzers, H_2 purification and compression units, utility connections for water and power*
	**Storage vessels**[135]**:** *Above-ground storage vessels (liquefied), utility connections for power*
	**Underground storage**[135]*: Underground storage in depleted oil fields or salt caverns, utility connections for power*
	**Liquefied hydrogen:** *Cryogenic liquefaction plants, utility connections for power*
	**Hydrogen regasification:** *Regasification units, heating systems, utility connections for power*
	**Pipeline:** *Pipelines, recompression stations along the pipeline, sub-stations for utility connections for power*

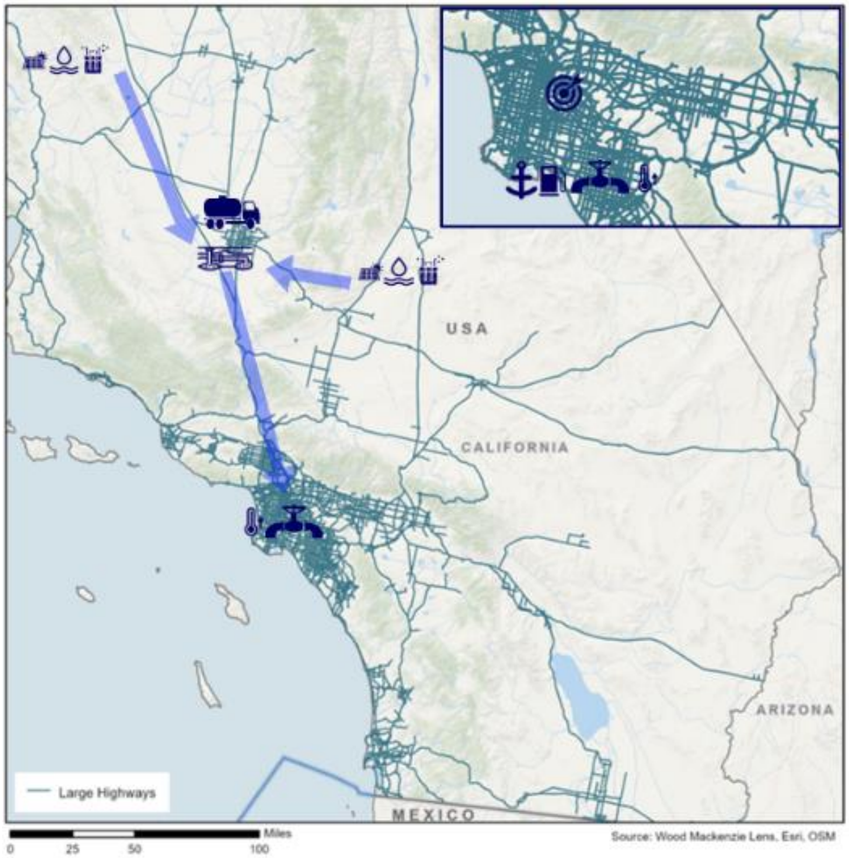
[135] Additional detail for storage considerations can be found on Appendix 7.5.1.

Icon	Icon Name Infrastructure & Peripherals
	**Trucked hydrogen:** *H_2 transport trucks (compressed or liquefied), filling and offloading stations, fuel stations*
	**Shipped hydrogen:** *H_2 vessels (as liquefied or methanol), port facilities for loading and unloading, reforming/cracking for methanol shipping*

7.2.2.1. Liquid Hydrogen Shipping

Production of hydrogen in Central and Northern California is transported via a pipeline to a liquefaction terminal in the nearby port. Liquid hydrogen is loaded into 10,000 cubic meter vessels (approximately 700 tonnes). These vessels transport the hydrogen to L.A. Ports, which are transferred into liquid storage vessels and then regasified at the terminal to be directly serviced at the interconnection point at the Ports. This alternative assumes a distribution pipeline is developed in the L.A. Basin with interconnection to end users, including the Ports.

Figure 19: Liquid Hydrogen Shipping Map and Components



Component	Key Infrastructure for Scenario 7
Production	39.9 GW solar plants
	1.5 mtpa from Northern California 133 | 200 MW electrolyzers equivalent to 26.6 GW capacity 14.7 MGD water feedstock
Storage	Above-ground storage at ports in a 135-acre, 610 liquid sphere farm

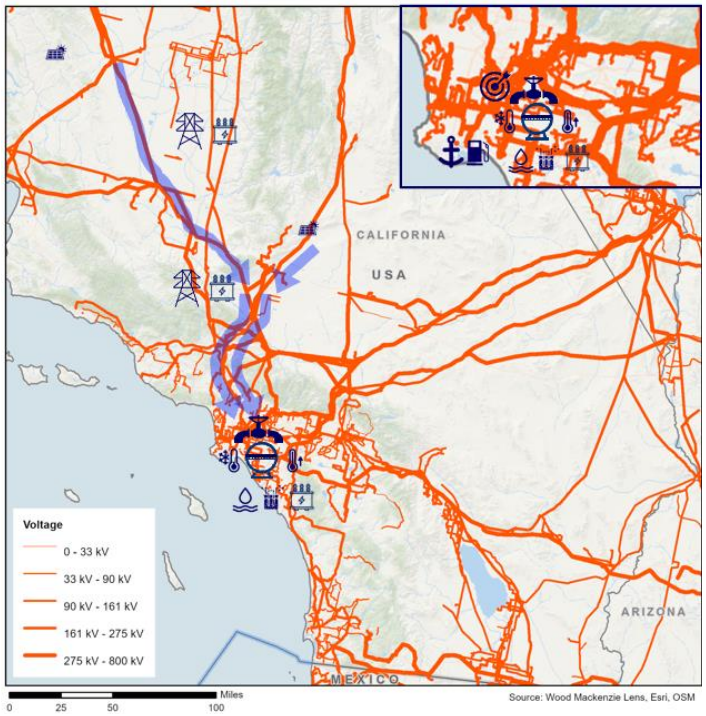
Transmission	27 ships making 2,100 round trips a year to transport 1.5 mtpa from Northern California to L.A. ports
Delivery	~80-mile delivery pipeline

7.2.2.2. Power T&D with In-Basin Production

This alternative involves transmitting renewable energy as electrons through multiple 500 kV AC electric power lines, connecting solar production sites to the L.A. Basin generally following potential conceptual Angeles Link pipeline corridors.[136] Hydrogen production would occur in-basin, with a distribution pipeline interconnection to end users, including the Ports. This assumes all new transmission lines with no interconnection to the existing grid. To meet reliability requirements, this option assumes liquid storage in-basin.

[136] A 500kV AC transmission system was selected in order to meet the capacity requirements for the Delivery Alternative. The 500kV system is largely compatible with the CAISO grid, which is mostly AC. As discussed in Appendix 7.3.1.2.4, the effective load carrying capacity for a typical 500kV AC transmission system does not exceed 3GW, rapidly declining with the transmitting distance. Hence, supporting 26.6 GW of electricity load requirement (in addition to the 1.8 GW of transmission load losses) for hydrogen production would require multiple transmission lines consisting of 10 double circuit and 1 single circuit transmission system (for a total of 21 circuits) across a 400-mile transmission corridor (accounting for a total of 2,500 miles of transmission). See Appendix 7.2.2 and 7.3.1 for additional details.

Figure 2020: Power T&D with In-Basin Production Map and Components

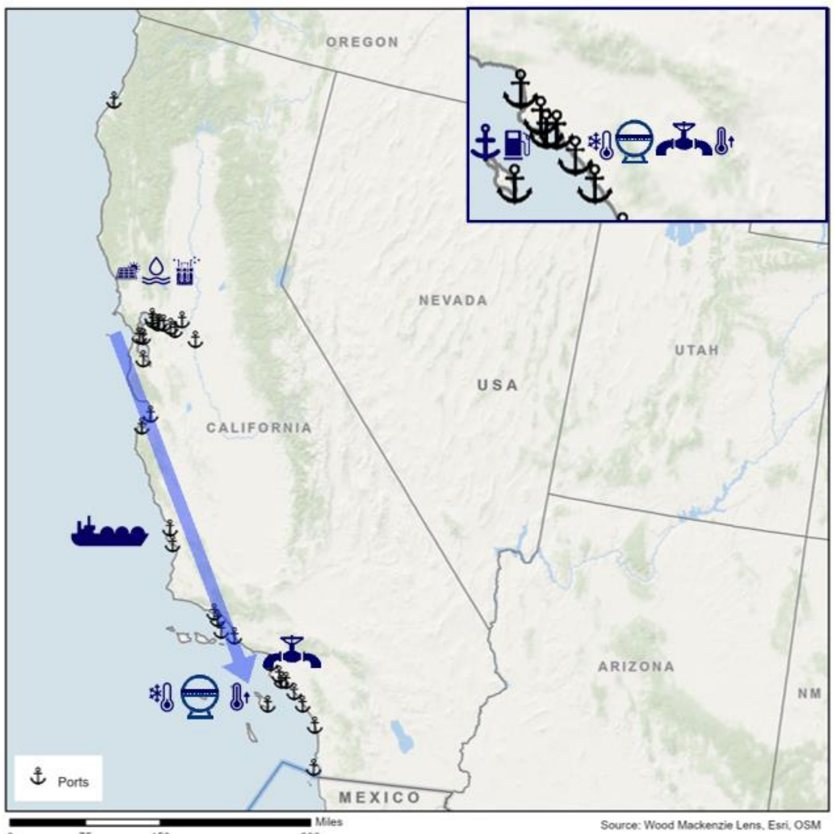


Component	Key Infrastructure for Scenario 7
Production	43 GW solar plants
	1.5 mtpa produced in L.A. basin 133 | 200 MW electrolyzers equivalent to 26.6 GW capacity 14.7 MGD water feedstock
Storage	In-basin production requires 135 acres, or 610 liquid spheres for above-ground storage
Transmission	400 miles of new 500 kV transmission line corridor needed from SJV and Lancaster to L.A. basin. It needs 4 substations and 308 transformers
Delivery	~80-mile delivery pipeline

7.2.2.3. Methanol Shipping

Production of hydrogen in Central and Northern California is transported via a pipeline to a methanol conversion plant in nearby ports. The methanol is transferred onto a methanol vessel intended to transport hydrogen as methanol to L.A. Ports. Methanol is then transferred into a methanol-to-hydrogen reconversion facility. After reconversion, the hydrogen is stored as liquid hydrogen before being regasified to be directly serviced at the interconnection point at the Ports. This alternative assumes a distribution pipeline is developed in the L.A. Basin with interconnection to end users, including the Ports.

Figure 2121: Methanol Shipping Map and Components

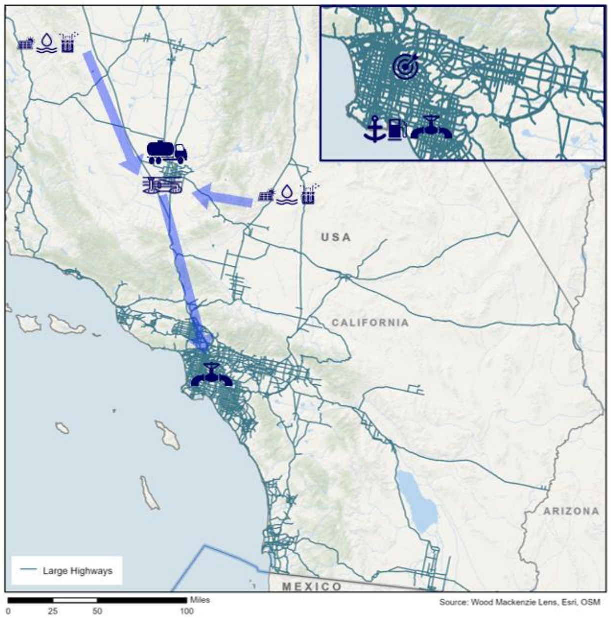


Component	Key Infrastructure for Scenario 7
Production	39.9 GW solar plants
	1.5 mtpa from Northern California 133 | 200 MW electrolyzers equivalent to 26.6 GW capacity 14.7 MGD water feedstock
Storage	Above-ground storage at ports in a 135 acres, 610 liquid sphere farm
Transmission	1 to 2 ships making 60 round trips a year to transport 1.5 mtpa from Northern California to L.A. ports
Delivery	~80-mile delivery pipeline

7.2.2.4. Gaseous Hydrogen Trucking

Hydrogen produced at the identified production locations is compressed and loaded at production facilities, then transported to end users via compressed hydrogen trucks. Each truck can transport up to 1 tonne of hydrogen per load, while loading bays can dispatch 5 trucks per day. Assumes vehicle stock turnover from diesel trucks to fuel cell electric drive trains in the 2030s to meet California's decarbonization goals. Trucks would use existing highways, following corridors similar to conceptual pipeline routes. This alternative assumes the use of underground storage (such as depleted oil fields), which would be connected via gaseous trucks. This alternative assumes a distribution pipeline is developed in the L.A. Basin with interconnection to end users, including the Ports.

Figure 2222: Gaseous Hydrogen Trucking Map and Components



Component	Key Infrastructure for Scenario 7
Production	39.9 GW solar plants
	0.75 mtpa from SJV and 0.75 mtpa from Lancaster 133 | 200 MW electrolyzers equivalent to 26.6 GW capacity 14.7 MGD water feedstock
Storage	Underground storage in depleted oil fields
Transmission	12,700 trucks and 3,400 loading bays required to serve maximum day capacity on a year, 127 vehicle-miles[137] for Scenario 7
Delivery	~80-mile delivery pipeline

[137] 127 vehicle-miles in this context equates to a 127-mile chain of contiguous gaseous hydrogen trucks in a single day.

7.2.2.5. Localized Hub[138]

A dedicated clean renewable hydrogen pipeline system located within the L.A. Basin with production and end use in close proximity that could support connections between the state's decarbonization projects within the ARCHES portfolio. This Localized Hub connects clean renewable hydrogen producers to multiple end users in the hard-to-electrify sectors via open access, common carrier pipeline infrastructure. The Localized Hub within the L.A. Basin is fed only by in-basin production and/or production in close proximity to multiple in-basin end users and storage. The considerations for the Localized Hub are split into two areas: A) Geography and B) Value Chain Evaluation.

- **A. Geography** The L.A. Basin is a geographically defined area in Southern California; a coastal plain bounded by the Pacific Ocean to the west and surrounded by mountains and hills, including the Santa Monica Mountains to the north, the San Gabriel mountains to the northeast, and the Santa Ana Mountains to the southeast. The L.A. Basin encompasses the central part of Los Angeles County, including portions of the San Fernando Valley, and extends into parts of Orange, Riverside and San Bernardino counties.
- **B. Value Chain Evaluation** The Localized Hub is characterized and analyzed to account for the hydrogen value chain to support local production, transport, storage, and delivery systems and the associate feasibility considerations.
    - a. **Production**: The Localized Hub considers production within and in close proximity to multiple in-basin end users and storage and will assess production prospects within a 40-mile radius expanding outward from the area of concentrated demand near the Ports of Los Angeles and Long Beach. This approach is designed to encompass the L.A. Basin and those outskirt areas close to multiple in-basin end users and storage. See Figure 23 below for a map depicting L.A. Basin and close proximity boundary.

      Hydrogen production will include two primary feedstocks: solar energy and biomass. Regarding solar energy, the assessment will include feasibility of constructing independent solar power sites. Biomass will focus on the utilization of woody biomass and the conversion of municipal waste.

[138] "SoCalGas shall study a localized hydrogen hub solution, under the specifications required to be eligible for federal funding provided through the Infrastructure Investment and Jobs Act, as part of Phase One." (D.22-12-055, p. 74.).

b. **Target Demand Sectors**: The Hub aims to address the dedicated demand from multiple sectors within the L.A. Basin contributing to a reduction in GHG emissions and will seek to meet the diverse capacity and unique consumption patterns of the different end use applications. These sectors include the following:
    i. Power Generation: Supporting the transition to cleaner energy solutions for public and private power generation facilities.
    ii. Industrial & Commercial Manufacturing: Catering to the energy and feedstock demands of factories, processing plants, and other industrial and manufacturing end users.
    iii. Mobility: Especially focusing on heavy-duty trucking operations emerging from ports, which require substantial low-carbon and zero-carbon energy solutions. The Localized Hub's close proximity to ports provides efficient fueling solutions for these heavy-duty transport systems.

c. **Pipeline Transmission**: Within the Hub, hydrogen would be transported through a series of high-pressure trunk transmission pipelines to connect production and offtake and facilitate potential connections to third-party storage facilities. The pipeline system would be designed for safe, efficient, and rapid transport of hydrogen from production sources located within or close to multiple delivery points within the L.A. Basin. For purposes of the feasibility stage, the Hub is assumed to include approximately 80 miles of transmission pipeline within the 40-mile radius for production and storage assessed for the Hub. This mileage corresponds to the miles of transmission pipeline that would be located within the L.A. Basin for the Angeles Link preferred routes, as this provides a baseline for potential transmission needs for the Hub to connect well-known demand centers near the Ports of Los Angeles and Long Beach. The total mileage of pipelines for the Hub may be greater, as land constraints may result in more distributed production facilities and additional pipeline mileage needed for transmission and distribution to meet the production, demand, and storage needs.

d. **Storage**: In the intermittence of synchronized production and demand, reserve hydrogen would be stored above-ground. Storage solutions within a 40-mile radius expanding from the area of concentrated demand near the Ports of Los Angeles and Long Beach are considered with regard to their high-level suitability and technology readiness level.

Figure 2323: Localized Hub Area Map

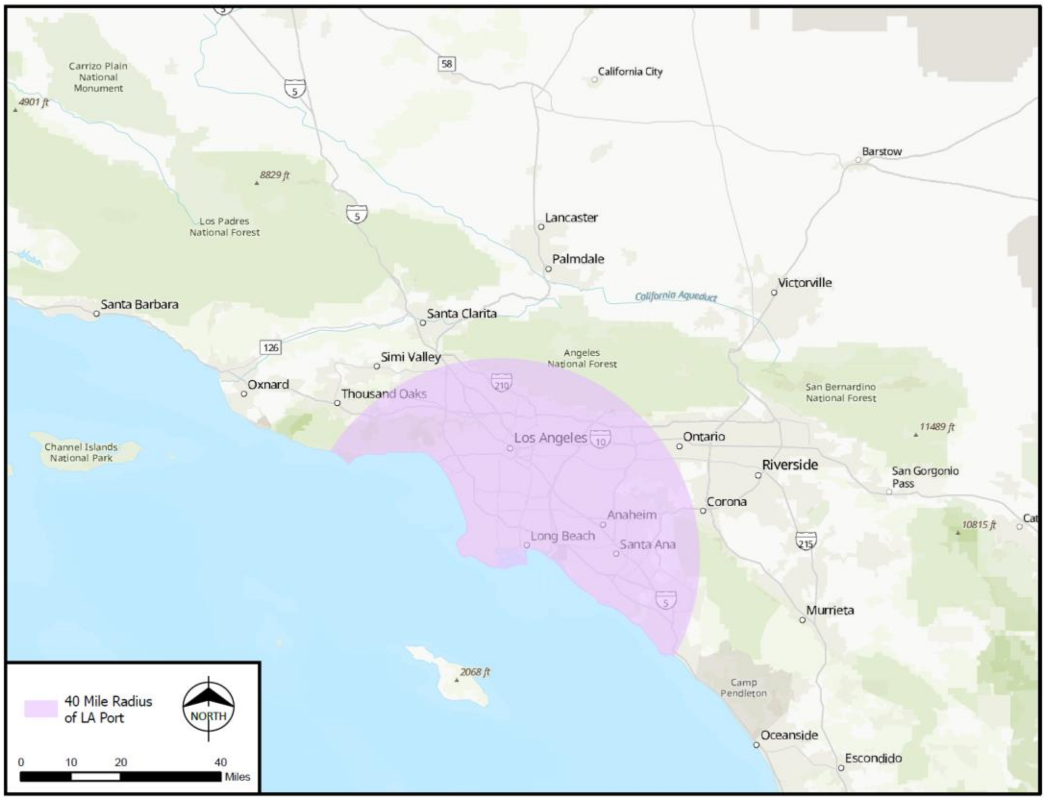
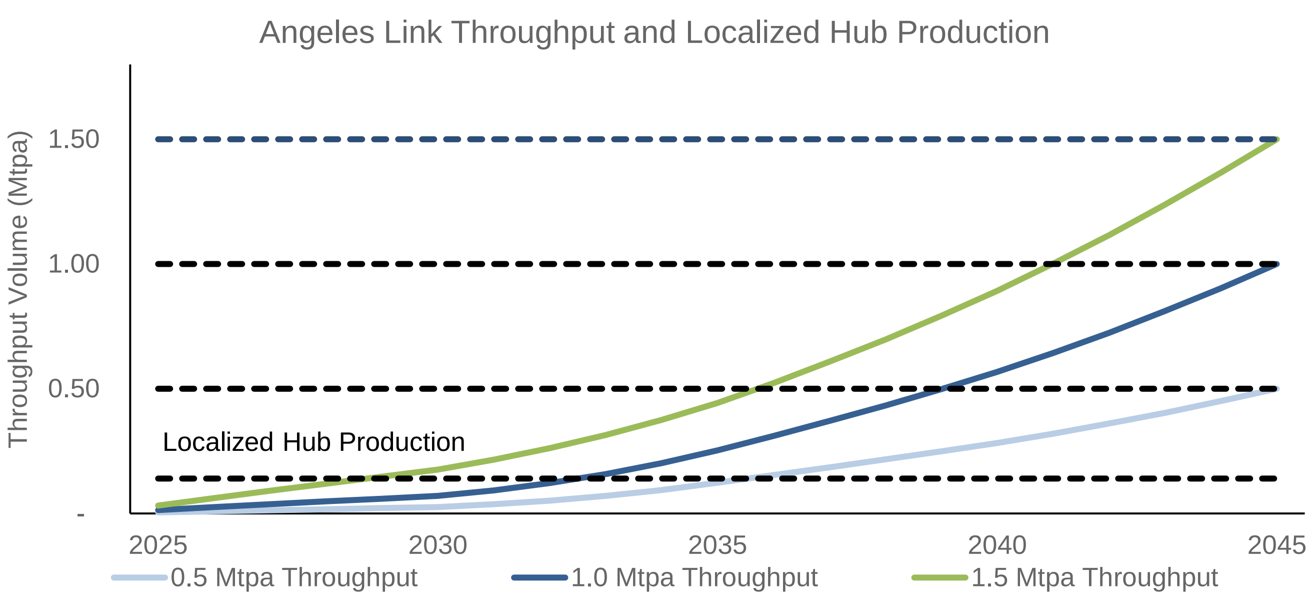


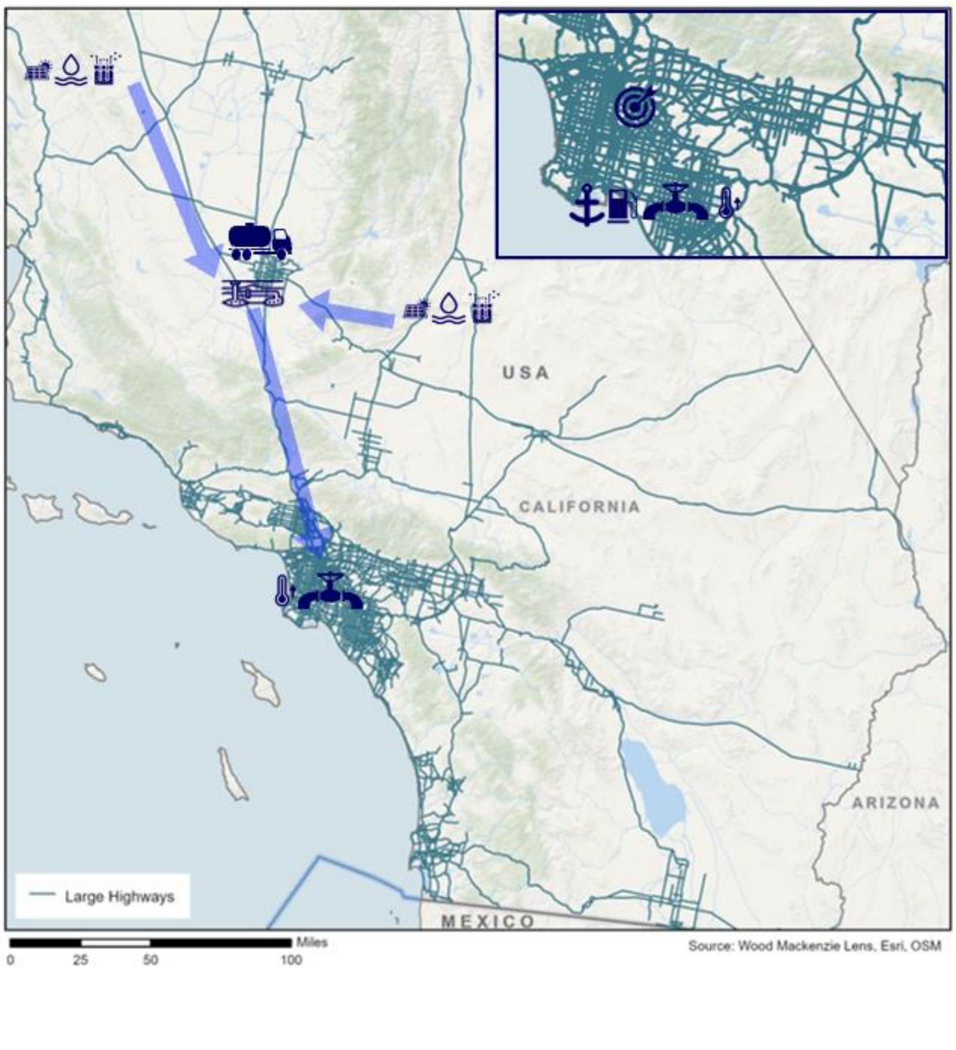
Figure 2424: Angeles Link Throughput and Localized Hub Production



7.2.2.6. Liquid Hydrogen Trucking

Hydrogen produced at the defined production locations is liquefied and loaded at each production site to liquid hydrogen trucks and then transported to end users. Each truck can transport up to 4 tonnes (metric tons) of hydrogen per load, while loading bays can dispatch 4 trucks per day. Assumes vehicle stock turnover from diesel trucks to fuel cell electric drive trains in the 2030s to meet California's decarbonization goals. Trucks would use existing highways, following corridors similar to conceptual pipeline routes. This alternative assumes the use of underground storage (such as depleted oil fields), which would be connected via liquid trucks. Assumes a distribution pipeline is developed in the L.A. Basin with interconnection to end users, including the Ports of Los Angeles and Long Beach (Ports).

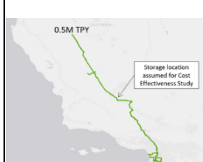
Figure 2525: Liquid Hydrogen Trucking Map and Components



Component	Key Infrastructure for Scenario 7
Production	39.9 GW solar plants
	0.75 mtpa from SJV and 0.75 mtpa from Lancaster 133 | 200 MW electrolyzers equivalent to 26.6 GW capacity 14.7 MGD water feedstock
Storage	Underground storage in depleted oil fields
Transmission	3,200 trucks and 700 loading bays required to serve maximum day capacity, 32 vehicle-miles on the road for scenario 7[139]
Delivery	~80-mile delivery pipeline

7.2.3. Angeles Link & Delivery Alternatives Scenarios Configurations

Table 19: Angeles Link Production Scenarios vs. Hydrogen Delivery Alternatives

Scenario	Map	Demand	Delivery Methods	Production (mtpa)					Storage		
				SJV	Lancaster	Blythe	Northern California	In-Basin	Depleted Oil Fields	Salt Caverns	Above-Ground
1		0.5 mtpa	Angeles Link	0.5					✓		
			Trucking	0.5					✓		
			Shipping				0.5				✓
			In-Basin Prod.	N/A							✓

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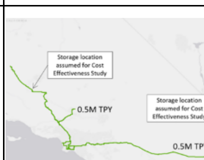
[139] 32 vehicle-miles in this context equates to a 32-mile chain of contiguous liquid hydrogen trucks in a single day.

Scenario	Map	Demand	Delivery Methods	Production (mtpa)					Storage		
				SJV	Lancaster	Blythe	Northern California	In-Basin	Depleted Oil Fields	Salt Caverns	Above-Ground
			Localized Hub					0.14			✓
2		0.5 mtpa	Angeles Link		0.5				✓		
			Trucking		0.5				✓		
			Shipping				0.5				✓
			In-Basin Prod.	N/A							✓
			Localized Hub					0.14			✓
3		0.5 mtpa	Angeles Link			0.5				✓	
			Trucking			0.5				✓	
			Shipping				0.5				✓
			In-Basin Prod.	N/A							✓
			Localized Hub					0.14			✓
4		1.0 mtpa	Angeles Link	0.5	0.5				✓		
			Trucking	0.5	0.5				✓		
			Shipping				1.0				✓
			In-Basin Prod.	N/A							✓
			Localized Hub					0.14			✓
5		1.0 mtpa	Angeles Link		0.5	0.5			✓	✓	
			Trucking		0.5	0.5			✓	✓	
			Shipping				1.0				✓

Scenario	Map	Demand	Delivery Methods	Production (mtpa) SJV	Lancaster	Blythe	Northern California	In-Basin	Storage Depleted Oil Fields	Salt Caverns	Above-Ground
			In-Basin Prod.	N/A							✓
			Localized Hub					0.14			✓
6		1.0 mtpa	Angeles Link	0.5		0.5			✓	✓	
			Trucking	0.5		0.5			✓	✓	
			Shipping				1.0				✓
			In-Basin Prod.	N/A							✓
			Localized Hub					0.14			✓
7		1.5 mtpa	Angeles Link	0.75	0.75				✓		
			Trucking	0.75	0.75				✓		
			Shipping				1.5				✓
			In-Basin Prod.	N/A							✓
			Localized Hub					0.14			✓
8		1.5 mtpa	Angeles Link	0.5	0.5	0.5			✓	✓	
			Trucking	0.5	0.5	0.5			✓	✓	
			Shipping				1.5				✓
			In-Basin Prod.	N/A							✓
			Localized Hub					0.14			✓

7.3. Assumptions Tables

7.3.1. Hydrogen Delivery Alternatives

7.3.1.1. Production

Table 20 below is shows a summary of the Production Cost Input Assumptions and their sources. Hydrogen production costs were assumed to be the same for all delivery alternatives, except the localized hub.[140] Extended cost input assumptions for hydrogen production can be found in the Production Study.

[140] While costs were the same, each delivery alternative had different losses (per Appendix 7.3.1.7) along the value chain, which means the LCOH would show slight variations.

Table 20: Production Cost Input Assumptions

Parameter	Unit	Angeles Link & Delivery Alternatives (Except Localized Hub)	Source
Power Production Facility			
Solar facility CAPEX	$/kW, real 2024	$1,125	Production Study
Solar facility OPEX	$/kW/year, real 2024	$20	
Solar capacity factor	%	26.4%	
Hydrogen Production Facility			
Electrolyzer CAPEX	$/kW, real 2024	$2,707	Production Study
Electrolyzer OPEX	% of CAPEX	0.7%	
Stack replacement CAPEX	$/kW, real 2024	$509	
Stack replacement frequency	years	10	
Electrolyzer plant efficiency	kWh/kgH_2	60	
Hydrogen production technology	N/A	PEM Electrolyzer	
Input for LCOH for Scenario 7			
Discounted total costs (CAPEX, OPEX, and PTC)	US$ MM, real 2024	$74,809	N/A

7.3.1.2. Transmission

7.3.1.2.1.Angeles Link System

Additional cost information can be found in the Pipeline Design Study.

Table 21 below shows a summary of the Angeles Link transmission cost input assumptions for Scenario 7. Additional cost information can be found in the Pipeline Design Study.

Table 21: Angeles Link System Cost Input Assumptions for Scenario 7

Parameter	Unit	Value	Source
Inputs from Design Study			
Pipeline CAPEX	US$ MM, real 2024	$7,471.06	Design Study
Compressor Station CAPEX	US$ MM, real 2024	$3,673.23	
Pipeline O&M	% of pipeline CAPEX	1%	
Compressor fixed O&M	% of compressor CAPEX	1%	
Compressor power requirement	kWh/kgH_2	0.36 - 0.40	
Key infrastructure requirements			
Total transmission pipeline length[141]	mi	310	Design Study
Total compressor power capacity	hp	100,000	
Number of compressor stations	#	2	
Input for LCOH			
Discounted total costs (CAPEX and OPEX)	US$ MM, real 2024	$11,243	N/A

Note: In line with the treatment for all delivery alternatives, the pipeline CAPEX was adjusted to meet the estimated maximum daily throughput requirements from production facilities to either storage or delivery in Central and Southern California and estimated maximum daily draw from storage to Central and Southern California. The key infrastructure requirements and inputs for LCOH correspond to the Scenario 7 for 1.5 Mtpa.

7.3.1.2.2.Trucking

The table below shows the gaseous trucking and liquid trucking transmission cost input assumptions.

141 Excludes the approximately 80-mile delivery system.

Table 22: Trucking Cost Input Assumptions

Parameter	Unit	Gaseous Hydrogen Trucking	Liquid Hydrogen Trucking[142]	Source
Terminal				
Loading bay capacity	tpd	4	20	National Petroleum Council[143]
CAPEX per bay	US$ MM, real 2024	$11.09	$105.94	
Fixed O&M loading bay	% of CAPEX	5.0%	3.3%	
Electricity consumption	kWh/kgH_2	3	10	
Delivery Trucks				
CAPEX, trucks, and trailers	US$ MM, real 2024	$1.18	$1.41	National Petroleum Council
Fixed O&M	US$ per truck, real 2024	$70,627	$188,340	
Variable O&M (non-fuel)	US$/mi, real 2024	$1.61	$1.29	
Variable O&M (fuel)	MJ/mi	20		
Truck speed (average)	Mph	35		
Loading / unloading time	hours	1.45		
On-trailer capacity	Ton H_2	1	4	

[142] Additional Liquid Hydrogen Trucking assumptions can be found in Table 25.
[143] National Petroleum Council. https://harnessinghydrogen.npc.org/.

Parameter	Unit	Gaseous Hydrogen Trucking	Liquid Hydrogen Trucking[142]	Source
Truck lifecycle	years	12		
Key Infrastructure Requirements for Scenario 7				
Loading terminals required	#	3,428	686	N/A
Trucks required	#	12,760	3,190	
Total miles per year	Million mi	618	155	
Input for LCOH for Scenario 7				
Discounted total costs (CAPEX and OPEX)	US$ MM, real 2024	$108,380	$119,242	N/A

Note: The number of loading bays and trucks required were estimated to meet the maximum daily requirement of hydrogen over a one-year period. The total miles traveled per year were optimized for each scenario, so that the distance traveled from supply, to and from storage, and into demand sites was minimized. The parameters for Opex such as electricity consumption and O&M were estimated for the average utilization. For liquid hydrogen trucking, liquefaction costs were considered as part of transmission. Regasification costs were accounted for as a separate line item, please refer to Table 25 for additional information on liquid hydrogen trucking regasification.

7.3.1.2.3.Shipping

The table below shows a summary of the shipping cost input assumptions used to estimate shipping cost.

Table 23: Shipping Cost Input Assumptions

Parameter	Unit	Liquid Hydrogen Shipping[144]	Methanol Shipping[145]	Source
CAPEX and OPEX				
CAPEX per vessel	US$ MM, Real 2024	$51.02	$217.77	Wood Mackenzie Hydrogen Midstream Model
Fixed O&M	% of CAPEX	4.45%	4.45%	
Port charge (loading / unloading)	US$ MM, Real 2024	$0.03	$0.20	
Operational Parameters				
Ship size	Cubic meters	10,000	174,000	Wood Mackenzie Hydrogen Midstream Model
Ship speed	knots	19		
On hire days	days	350		
Fill rate	%	98.5%		
Port days loading / unloading	days	0.75	1.50	
Port fuel consumption	tpd	4	25	
At sea fuel consumption (laden and ballast)	tpd	64	210	
Key Infrastructure Requirements for Scenario 7				
Vessels required	#	27	1	N/A

[144] Additional Liquid Hydrogen Shipping assumptions can be found in Table 25.
[145] Additional Methanol Shipping assumptions can be found in Table 26.

Parameter	Unit	Liquid Hydrogen Shipping[144]	Methanol Shipping[145]	Source
Round trips required	#	2,125	57	
Input for LCOH for Scenario 7				
Discounted total costs (CAPEX and OPEX)	US$ MM, real 2024	$4,712	$616	N/A

Note: The number of ships was estimated to meet the maximum daily requirement over a one-year period.

7.3.1.2.4.Power T&D

The table below shows a summary of the shipping cost input assumptions used to estimate shipping cost.

Table 24: Power T&D Cost Input Assumptions

Parameter	Unit	Value	Source
CAPEX and Operational Parameters			
CAPEX single circuit transmission line	US$ MM, real 2024	$5.95	Southern California Edison142F[146]
CAPEX double circuit transmission line	US$ MM, real 2024	$10.78	
CAPEX Substation	US$ MM, real 2024	$47.68	
CAPEX transformer (500/230 kV, 1,120 MVA)	US$ MM, real 2024	$37.84	
CAPEX transformer (230/66 kV, 280 MVA)	US$ MM, real 2024	$8.78	
Operational Parameters			
Transmission line voltage	kV	500	

[146] Southern California Edison, https://www.caiso.com/documents/sce2022finalperunitcostguide.xlsx.

Parameter	Unit	Value	Source
Power factor	Factor	0.80	CAISO and PG&E operating metrics for typical 500 kV equipment
Transformer capacity (1,120 MVA)	GW	0.896	
Transformer capacity (280 MVA)	GW	0.224	
Transmission line losses	% per 100 mi	1.30%	
Transformer losses	%	2.00%	
Power Carrying Capacity (500 kV AC transmission lines)			
From 0 to 50 miles	MW	3,040	U.S. Department of Energy[147]
From 51 to 100 miles	MW	2,080	
From 101 to 200 miles	MW	1,320	
From 201 to 300 miles	MW	1,010	
From 301 to 400 miles	MW	810	
From 401 to 500 miles	MW	680	
From 501 to 600 miles	MW	600	
Key Infrastructure Requirements for Scenario 7			
New transmission lines miles	Miles	400	N/A
New transmission lines[148]	#	21	
Substations required	#	4	
Transformers	#	308	
Input for LCOH for Scenario 7			

[147] U.S. Department of Energy, https://www.energy.gov/sites/default/files/2023-02/022423-DRAFTNeedsStudyforPublicComment.pdf.

[148]The number of lines required depends on the power generation capacity and carrying capacity for the distance from supply to sub-station. 26.6 GW is the electricity need for the electrolysis process. Total generation also accounts for transmission losses of 1.8 GW for the scope configuration of Scenario 7 of the in-basin hydrogen production with power T&D alternative. Total installed solar capacity is estimated at 43 GW in the Production Study to account for intra-day availability. The assumption in Scenario 7 is fourteen single circuit (seven double circuit) lines from SJV to the L.A. Basin (assumes a 300-mile distance), and seven single circuit (three double circuit plus one single circuit) lines from SJV to the L.A. Basin (assumes a 100-miles distance) across a 400 mile transmission corridor.

Parameter	Unit	Value	Source
Discounted total costs (CAPEX and OPEX)	US$ MM, real 2024	$28,889	N/A

Note: The number of transmission lines was estimated to meet the maximum daily requirement over a one-year period.

7.3.1.3. Liquefaction and Regasification

The table below shows a summary of the cost input assumptions for liquefaction for liquid hydrogen shipping and regasification for liquid hydrogen shipping and liquid hydrogen trucking.

Table 25: Liquefaction and Regasification Cost Input Assumptions

<table>
<tr><th>Parameter</th><th>Unit</th><th>Liquid Hydrogen Shipping</th><th>Liquid Hydrogen Trucking</th><th>Source</th></tr>
<tr><td colspan="5">Liquefaction</td></tr>
<tr><td>CAPEX per liquefaction train</td><td>US$ MM, real 2024</td><td>$125</td><td rowspan="5">Inc. in transmission costs as part of loading bays</td><td rowspan="5">Wood Mackenzie Hydrogen Midstream Model</td></tr>
<tr><td>Fixed O&M</td><td>% of CAPEX</td><td>1.0%</td></tr>
<tr><td>Liquefaction power consumption</td><td>kWh/kgH_2</td><td>10</td></tr>
<tr><td>Liquefaction train size</td><td>tpd</td><td>30</td></tr>
<tr><td>Number of liquefaction trains required</td><td>#</td><td>136</td></tr>
<tr><td colspan="5">Regasification</td></tr>
<tr><td>CAPEX regasification terminal</td><td>US$/Nm^3/h, real 2024</td><td>$956.38</td><td>$956.38</td><td rowspan="2">Wood Mackenzie Hydrogen Midstream Model</td></tr>
<tr><td>CAPEX liquid storage tanks</td><td>US$/m^3, real 2024</td><td>$4,251</td><td>$4,251</td></tr>
</table>

Parameter	Unit	Liquid Hydrogen Shipping	Liquid Hydrogen Trucking	Source
Fixed O&M	% of CAPEX	1.24%	1.24%	
Key Infrastructure Requirements for Scenario 7				
Total power consumption	GWh/year	539	539	N/A
Input for LCOH for scenario 7				
Discounted total costs (CAPEX and OPEX)	US$ MM, real 2024	$23,235	$2,965	N/A

Note: Liquefaction and regasification infrastructure was estimated to meet the maximum daily requirements over a one-year period. For liquid hydrogen trucking, the liquefaction costs were assumed to be part of transmission since loading bays include liquefaction and loading costs.

7.3.1.4. Methanol Production and Hydrogen Reconversion

The table below shows a summary of the cost input assumptions for methanol production and hydrogen reconversion for methanol shipping.

Table 26: Methanol Production and Hydrogen Reconversion Cost Input Assumptions

<table>
<tr><th>Parameter</th><th>Unit</th><th>Methanol Production</th><th>Hydrogen Reconversion</th><th>Source</th></tr>
<tr><td colspan="5">Methanol Production and Hydrogen Reconversion</td></tr>
<tr><td>CAPEX methanol plant</td><td>US$ MM/tpd H_2, real 2024</td><td>$2.49</td><td>$6.08</td><td rowspan="3">Wood Mackenzie Hydrogen Midstream Model</td></tr>
<tr><td>CAPEX methanol storage</td><td>US$/$m^3$, real 2024</td><td colspan="2">$311.06</td></tr>
<tr><td>Fixed O&M</td><td>% of CAPEX</td><td>1.24%</td><td>0.90%</td></tr>
<tr><td colspan="5">Key Infrastructure Requirements for Scenario 7</td></tr>
<tr><td>Total power consumption</td><td>GWh/year</td><td colspan="2">3,349</td><td>N/A</td></tr>
<tr><td colspan="5">Input for LCOH for Scenario 7</td></tr>
<tr><td>Discounted total costs (CAPEX and OPEX)</td><td>US$ MM, real 2024</td><td colspan="2">$50,294</td><td>N/A</td></tr>
</table>

Note: Methanol production and hydrogen reconversion infrastructure were estimated to meet the maximum daily requirements over a one-year period.

7.3.1.5. Distribution Pipeline

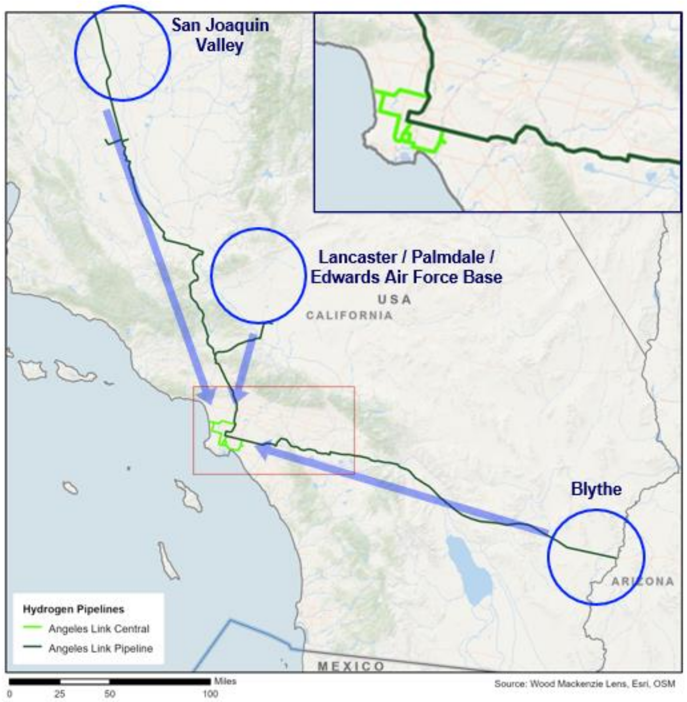
The table below shows the distribution pipeline cost input assumptions for Angeles Link. The same costs were assumed for all delivery alternatives. For the purposes of this study, WM assumed that the pipelines within the LA Basin could provide potential connections to major end-users and therefore facilitate last-mile delivery.

Table 27: Distribution Cost Input Assumptions

Parameter	Unit	Value for all Delivery Alternatives	Source
Inputs from Design Study			
Distribution pipeline CAPEX	US$ MM, real 2024	$1,436.60	Design Study
Distribution pipeline O&M	% of pipeline CAPEX	1%	
Key infrastructure requirements for Scenario 7			
Distribution pipeline length	mi	80	Design Study
Input for LCOH for Scenario 7			
Discounted total costs (CAPEX and OPEX)	US$ MM, real 2024	$1,419	N/A

Note: Distribution costs were modeled to match the delivery costs of the Angeles Link Central per Figure 26 below for each delivery alternative.

Figure 2626: Illustrative Map of Angeles Link and Delivery Alternatives Key Locations[149]



7.3.1.6. Storage

For additional storage assumptions, refer to Appendix 7.5.1. For the localized hub alternative, the above-ground storage requirements were assumed to be the same on a $/Kg$H_2$ and the total costs were adjusted to match the localized hub production volumes.

[149] The systems would be designed to serve demand along their routes.

7.3.1.7. Losses by Delivery Alternative

Table 28: Hydrogen Losses by Delivery Alternative and Value Chain Segment

(%)	Angeles Link	Liquid Hydrogen Shipping	In-Basin Production w/Power T&D	Methanol Shipping	Gaseous Hydrogen Trucking	Localized Hub	Liquid Hydrogen Trucking	Source
Regasification or Hydrogen Reconversion	N/A	0.00%	0.00%	0.07%	N/A	N/A	0.00%	Wood Mackenzie Midstream Model
Liquefaction or Methanol Production	N/A	0.00%	N/A	0.00%	N/A	N/A	N/A	
Transmission	1.26%	0.32%	N/A	0.00%	N/A	N/A	N/A	
	N/A	N/A	N/A	N/A	2.00%	N/A	5.00%[150][151]	National Petroleum Council[151]
Storage	N/A	3.38%	3.37%	3.37%	N/A	N/A	N/A	
	0.02%	N/A	N/A	N/A	0.02%	N/A	0.02%	Angeles Link Hydrogen Leakage Study[152]
Delivery	0.57%	0.59%	0.58%	0.58%	0.58%	N/A	0.59%	
Production	2.00%	2.00%	2.00%	2.00%	2.00%	N/A	2.00%	
Total	**3.85%**	**6.29%**	**5.95%**	**6.02%**	**4.60%**	**N/A**	**7.61%**	

Assumptions on hydrogen losses across each delivery alternative's value chain segments determine the final volume delivered.

[150] Includes liquefaction losses.
[151] National Petroleum Council. (2024). https://harnessinghydrogen.npc.org/
[152] Angeles Link Hydrogen Leakage Study.

7.3.2. Non-Hydrogen Alternatives Assumption Tables

7.3.2.1. Mobility

Table 29: Techno-Economic Assumptions: Class 8 Sleeper Cab (2030)

<table>
<tr><th>Assumptions</th><th>Low</th><th>Base</th><th>High</th><th>Sources</th></tr>
<tr><td colspan="5">Fuel economy (MPGe)</td></tr>
<tr><td>FCEV</td><td colspan="3">13</td><td rowspan="2">Argonne National Laboratory</td></tr>
<tr><td>BEV</td><td colspan="3">23</td></tr>
<tr><td colspan="5">Tank range (mi):</td></tr>
<tr><td>FCEV</td><td colspan="3">420</td><td rowspan="2">Representative vehicle specifications from OEMs</td></tr>
<tr><td>BEV</td><td colspan="3">275</td></tr>
<tr><td colspan="5">Purchase cost ($k):</td></tr>
<tr><td>FCEV</td><td colspan="2">228</td><td>456</td><td rowspan="4">Argonne National Laboratory</td></tr>
<tr><td>BEV</td><td colspan="2">255</td><td>510</td></tr>
<tr><td>Labor cost ($/mi)</td><td colspan="3">0.94</td></tr>
<tr><td>Dwell cost ($/hr)</td><td colspan="3">89</td></tr>
<tr><td colspan="5">Refueling rate (mins):</td></tr>
<tr><td>FCEV</td><td colspan="2">10</td><td>30</td><td>Argonne National Laboratory</td></tr>
<tr><td>BEV</td><td colspan="2">20</td><td>60</td><td>Argonne National Laboratory and TCO Model</td></tr>
<tr><td colspan="5">Fuel cost (net of applicable LCFS)</td></tr>
<tr><td>FCEV ($/kg)</td><td>4.51</td><td>6.01</td><td>7.51</td><td>Includes the LCOH from Angeles Link of $5.29 + $1.85 distribution cost + $0.70 dispensing cost - $2.04 LCFS credit pass through</td></tr>
<tr><td>BEV ($/kWh)</td><td>0.31</td><td>0.43</td><td>0.60</td><td>Assuming a SCE EV charging tariff and applying a retail projection along with a retail markup. Assuming LCFS credits are included in the retail markup</td></tr>
</table>

Table 30: Techno-Economic Assumptions: Transit Bus (2030)

Assumptions	Low	Base	High	Sources
Fuel economy (MPGe)				
FCEV		17		Argonne National Laboratory
BEV		29		
Tank range (mi):				
FCEV		370		Representative vehicle specifications from OEMs
BEV		300		
Purchase cost ($k):				
FCEV		311	623	Argonne National Laboratory
BEV				
Labor cost ($/mi)		0.94		
Dwell cost ($/hr)		89		
Refueling rate (mins):				
FCEV		10	30	Argonne National Laboratory
BEV		20	60	Argonne National Laboratory and TCO Model
Fuel cost (net of applicable LCFS)				
FCEV ($/kg)	4.51	6.01	7.51	Includes the LCOH from Angeles Link of $5.29 + $1.85 distribution cost + $0.70 dispensing cost - $2.04 LCFS credit pass through
BEV ($/kWh)	0.31	0.43	0.60	Assuming a SCE EV charging tariff and applying a retail projection along with a retail markup. Assuming LCFS credits are included in the retail markup

Table 31: Techno-Economic Assumptions: Class 8 Drayage (2030)

<table>
<tr><th>Assumptions</th><th>Low</th><th>Base</th><th>High</th><th>Sources</th></tr>
<tr><td colspan="5">Fuel economy (MPGe)</td></tr>
<tr><td>FCEV</td><td colspan="3">12</td><td rowspan="2">Argonne National Laboratory</td></tr>
<tr><td>BEV</td><td colspan="3">22</td></tr>
<tr><td colspan="5">Tank range (mi):</td></tr>
<tr><td>FCEV</td><td colspan="3">450</td><td rowspan="2">Representative vehicle specifications from OEMs</td></tr>
<tr><td>BEV</td><td colspan="3">200</td></tr>
<tr><td colspan="5">Purchase cost ($k):</td></tr>
<tr><td>FCEV</td><td colspan="2">185</td><td>371</td><td rowspan="4">Argonne National Laboratory</td></tr>
<tr><td>BEV</td><td colspan="2">166</td><td>331</td></tr>
<tr><td>Labor cost ($/mi)</td><td colspan="3">0.94</td></tr>
<tr><td>Dwell cost ($/hr)</td><td colspan="3">89</td></tr>
<tr><td colspan="5">Refueling rate (mins):</td></tr>
<tr><td>FCEV</td><td colspan="2">10</td><td>30</td><td>Argonne National Laboratory</td></tr>
<tr><td>BEV</td><td colspan="2">20</td><td>60</td><td>Argonne National Laboratory and TCO Model</td></tr>
<tr><td colspan="5">Fuel cost (net of applicable LCFS)</td></tr>
<tr><td>FCEV ($/kg)</td><td>4.51</td><td>6.01</td><td>7.51</td><td>Includes the LCOH from Angeles Link of $5.29 + $1.85 distribution cost + $0.70 dispensing cost - $2.04 LCFS credit pass through</td></tr>
<tr><td>BEV ($/kWh)</td><td>0.34</td><td>0.35</td><td>0.49</td><td>Assuming a SCE EV charging tariff and applying a retail projection along with a retail markup. Assuming LCFS credits are included in the retail markup</td></tr>
</table>

Table 32: Techno-Economic Assumptions: Class 8 Day Cab (2030)

Assumptions	Low	Base	High	Sources
Fuel economy (MPGe)				
FCEV		13		Argonne National Laboratory
BEV		23		
Tank range (mi):				
FCEV		500		Representative vehicle specifications from OEMs
BEV		300		
Purchase cost ($k):				
FCEV	201		402	Argonne National Laboratory
BEV	187		373	
Labor cost ($/mi)		0.94		
Dwell cost ($/hr)		89		
Refueling rate (mins):				
FCEV	10		30	Argonne National Laboratory
BEV	20		60	Argonne National Laboratory and TCO Model
Fuel cost (net of applicable LCFS)				
FCEV ($/kg)	4.51	6.01	7.51	Includes the LCOH from Angeles Link of $5.29 + $1.85 distribution cost + $0.70 dispensing cost - $2.04 LCFS credit pass through
BEV ($/kWh)	0.34	0.35	0.49	Assuming a SCE EV charging tariff and applying a retail projection along with a retail markup. Assuming LCFS credits are included in the retail markup

7.3.2.2. Power

Table 33: Techno-Economic Assumptions: Hydrogen Combustion Turbine Retrofit (2030)

Assumptions	Low	Base	High	Sources
Facility size (MW)		500		Wood Mackenzie LCOE Model
Net capacity factor (%)				
Baseload	60%	50%	40%	Wood Mackenzie LCOE Model
Peaking	11%	10%	9%	
Capex ($/kW)				
Baseload – retrofit	156	208	260	NPC Study
Peaking – retrofit	156	208	260	
Fixed O&M ($/kW-yr)				
Baseload	70	78	86	Wood Mackenzie LCOE Model
Peaking	51	56	62	
Variable O&M ($/MWh)				
Baseload	3	4	4	Wood Mackenzie LCOE Model
Peaking	11	13	14	
Fuel cost				
Angeles Link LCOH ($/kg)	4.13	5.50	6.88	Cost Effectiveness Study LCOH
Energy equivalent ($/MMBtu$_e$)	31	41	51	Conversion of LCOH to energy equivalent in MMBtu

Table 34: Techno-Economic Assumptions: Gas Turbine with CCS Retrofit (2030)

Assumptions	Low	Base	High	Sources
Facility size (MW)		500		Wood Mackenzie LCOE Model
Net capacity factor (%)	60%	50%	40%	
Capex ($/kW)				
Baseload - retrofit	1,243	1,775	2,308	Wood Mackenzie LCOE Model
Fixed O&M ($/kW-year)	64	91	119	Wood Mackenzie LCOE Model
Variable O&M ($/MWh)	4	5	7	
Fuel cost				
Delivered fuel cost ($/MMBtu$_e$)	3.6	4.5	5.4	Forecast of delivered gas price at SoCalGas Citygate
T&D adder ($/MMBtu)		3.5		Wood Mackenzie LCOE Model
CO_2 transport and sequestration ($/ton)	92		368	Wood Mackenzie CCS Model (California-specific)
45Q credit value ($/MWh)		18		Forecast reflecting outlook on current policy

Table 35: Techno-Economic Assumptions: Battery Storage Facility - 12 hour (2030)

Assumptions	Low	Base	High	Sources
Facility size (MW)		400		Based on Moss Landing, largest operating facility in California
Discharge duration (Hours)		12		Wood Mackenzie LCOE Model
Roundtrip efficiency (%)		86%		
Net capacity factor (%)	12%	10%	8%	Follows from duration and assumes 30+ cycles per year
Capex ($/kW)	2,526	3,367	4,209	Wood Mackenzie LCOE Model
Fixed O&M ($/kW-yr)	95	119	143	
Variable O&M ($/MWh)	10	13	16	
Charging cost ($/MWh)	44	59	71	Forecast of average annual wholesale price forecast for CAISO SP15
ITC (%)		30%		Forecast reflecting outlook on current policy

7.3.2.3. Cogeneration

Table 36: Techno-Economic Assumptions: Hydrogen Turbine Retrofit (2030)

Assumptions	Low	Base	High	Sources
Facility size (MW)		30		Wood Mackenzie LCOE Model
Net capacity factor (%)	69	58	46	
Capex ($/kW)	266	380	494	
Fixed O&M ($/kW-year)	105	117	129	
Variable O&M ($/MWh)	8	9	9	
Fuel cost				
Angeles Link LCOH ($/kg)	4.13	5.50	6.88	Angles Link LCOH
Energy equivalent ($/MMBtu$_e$)	31	41	51	Conversion of LCOH to energy equivalent in MMBtu

Table 37: Techno-Economic Assumptions: Gas Turbine with CCS Retrofit (2030)

Assumptions	Low	Base	High	Sources
Facility size (MW)		30		Wood Mackenzie LCOE Model
Net capacity factor (%)	69	58	46	
Capex ($/kW)	2,100	3,000	3,900	
Fixed O&M ($/kW-year)	124	137	151	
Variable O&M ($/MWh)	10	11	13	
Fuel cost				
Delivered fuel cost ($/MMBtu$_e$)	3.6	4.5	5.4	Forecast of delivered gas price at SoCal Citygate
T&D adder ($/MMBtu)		3.5		Wood Mackenzie North America Gas Model
CO_2 transport and sequestration ($/ton)	92		368	Wood Mackenzie CCS Model (California-specific)
45Q credit value ($/MWh)		18		Forecast reflecting outlook on current policy

7.3.2.4. Food & Beverage

Table 38: Techno-Economic Assumptions: Food & Beverage Alternatives (2030)

Assumptions	Low	Base	High	Sources
Hydrogen				
Delivered fuel cost ($/kg)	4.1	5.5	6.9	Angeles Link LCOH
Electricity				
Retail cost ($/MWh)	180	225	270	SCE Industrial Service Tariffs and Third-Party Forecasts
Green premium - CA REC prices ($/MWh)		25		Wood Mackenzie Long Term Power Model

7.3.2.5. Cement

Table 39: Techno-Economic Assumptions: Cement Alternatives (2030)

Assumptions	Low	Base	High	Sources
Hydrogen				
Delivered fuel cost ($/kg)	4.1	5.5	6.9	Angeles Link LCOH
Gas + CCS				
Delivered fuel cost ($/MMBtu)	3.6	4.5	5.4	Wood Mackenzie North America Gas and CCS Models
T&D adder ($/MMBtu)	3.5			
CO2 transport and sequestration cost ($/ton)	92		368	
Electricity				
Retail cost ($/MWh)	180	225	270	SCE Industrial Service Tariffs and Third-Party Forecasts
CA REC prices ($/MWh)	25			Wood Mackenzie Long Term Power Model

7.3.2.6. Refineries

Table 40: Techno-Economic Assumptions: Refinery Alternatives (2030)

Assumptions	Low	Base	High	Sources
Clean Renewable Hydrogen				
Delivered feedstock cost ($/kg)	4.1	5.5	6.9	Angeles Link LCOH
Hydrogen Abated with CCS				
Delivered feedstock cost ($/kg)	1.8		3.5	Wood Mackenzie LCOH Model
CO_2 transport and sequestration cost ($/ton)	92		368	Wood Mackenzie CCS Models (California-specific)

7.4. Results Tables

7.4.1. LCOH by Alternative Matrix

Table 41 below includes a summary of the LCOH ($\$/KgH_2$) estimated for all Angeles Link and delivery alternatives for all scenarios. For additional information on scenarios, refer to Appendix 7.2.2.6.

Table 41: Cost Effectiveness of Angeles Link vs. Alternatives for All Scenarios

LCOH ($\$/KgH_2$)	Angeles Link	Liquid Hydrogen Shipping	In-Basin Production w/Power T&D	Methanol Shipping	Gaseous Hydrogen Trucking	Localized Hub	Liquid Hydrogen Trucking
Scenario 1	$6.20	$8.14	$9.79	$9.14	$11.84	$12.03	$12.62
Scenario 2	$5.95	$8.11	$7.62	$9.11	$11.51	$12.03	$12.55
Scenario 3	$7.35	$8.11	$9.02	$9.11	$15.03	$12.03	$14.38
Scenario 4	$5.53	$8.33	$8.95	$9.34	$11.78	$12.03	$13.06
Scenario 5	$6.38	$8.32	$8.58	$9.33	$14.10	$12.03	$14.29
Scenario 6	$6.52	$8.33	$9.67	$9.34	$14.16	$12.03	$14.28
Scenario 7	$5.50	$8.21	$8.73	$9.20	$11.40	$12.03	$12.62
Scenario 8	$6.22	$8.20	$8.94	$9.19	$12.63	$12.03	$13.28

7.4.2. Delivery Alternatives Costs

Table 42 below includes a summary of the estimated cost by value chain segment for Angeles Link (per the Production Study and Design Study) and delivery alternatives. For additional information on the inputs for these costs, refer to Appendix 7.3.1.

Table 42: Discounted Costs by Delivery Alternatives and Value Chain Segment for Scenario 7

LCOH (US$MM)	Angeles Link	Liquid Hydrogen Shipping	In-Basin Production w/Power T&D	Methanol Shipping	Gaseous Hydrogen Trucking	Localized Hub	Liquid Hydrogen Trucking
Delivery	1,419	1,419	1,419	1,419	1,419	1,419	1,419
Regasification or Hydrogen Reconversion	0	3,013	0	25,541	0	0	2,965
Storage	4,603	26,920	37,880	37,880	4,603	3,536	4,603
Transmission	11,243	4,712	28,889	616	108,380	0	119,242
Liquefaction or Methanol Production	0	23,235	0	10,414	0	0	0
Production	74,809	74,809	74,809	74,809	74,809	15,207	74,809
Total	**92,074**	**134,108**	**142,997**	**150,679**	**189,211**	**20,162**	**203,038**

7.5. Key Considerations

7.5.1. Storage

Clean hydrogen production and above-ground and underground storage are not currently proposed as part of Angeles Link. As Angeles Link is further designed and, in alignment with the development of system requirements, the role of storage to support regional hydrogen producers and end users should be considered. During the early phases of the demand growth, above-ground storage (such as liquid hydrogen storage vessels) and, when pipelines are available, line pack, could potentially support the required storage needs for regional hydrogen producers and end users.[153]

The Alternatives Study and Cost Effectiveness Study were guided by the Production Study storage analysis, which evaluated conceptual hydrogen storage and associated storage injection and withdrawal flow trends enabling the technoeconomic assessments across various types of storage.[154] In line with these assumptions, the Alternatives Study and Cost Effectiveness Study included storage as a component of the Angeles Link pipeline system and Hydrogen Delivery Alternatives to support energy system reliability needs at a high level. This simplified approach did not consider how market demand for hydrogen and its storage will scale over time and how interim storage solutions may be utilized in the early phases of demand growth, as described above.

To analyze delivery alternatives in the Cost Effectiveness Study, two primary storage methods were considered for cost effectiveness evaluation: above-ground storage and underground storage, with underground storage further divided into salt caverns and depleted oil/gas reservoirs. Storage methods for each delivery alternative are location-bound, meaning the type of storage assumed depends on availability (or lack thereof) near the delivery alternative's value chain.

For third-party production regions, such as SJV and Lancaster, there is potential to use depleted oil/gas reservoirs near Bakersfield. To accommodate production near the L.A. Basin, specifically in-basin production, it was assumed it would be necessary to construct above-ground storage facilities. This is due to the unavailability of underground storage options within the L.A. Basin. In the context of above-ground storage, liquid storage vessels were chosen due to their higher energy density. When comparing above-ground compressed gaseous storage facilities to above-ground liquid hydrogen storage, the latter has the potential to address land

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[153] The Angeles Link pipeline system could also offer storage options through linepack. See Production Study, section 8.2 for additional information.

[154] See Production Study for additional information on storage.

limitations that may arise when implementing large-scale above-ground in-basin storage solutions.

The techno-economic parameters for cost-effectiveness evaluation are identified in Table 43. These parameters are based on external literature and have been prorated to meet the storage capacity and throughput requirements of the Angeles Link System (Scenario 7) and other delivery alternatives.[155,156]

[155] Some storage cost components were taken and adjusted to reflect Angeles Link capacity and throughput requirements from: Chen, F., Ma, Z., Nasrabadi, H., Chen, B., Mehana, M. Z. S., & Van Wijk, J. (2024). Capacity Assessment and Cost Analysis of Geologic Storage of Hydrogen: A Case Study in Intermountain-West Region USA. Los Alamos National Laboratory and Texas A&M University.
[156] National Petroleum Council. (2024). https://harnessinghydrogen.npc.org/.

Table 43: Storage Cost Parameters for Scenario 7[157]

Parameter	Unit	Underground		Above-ground Liquid Storage	Source
		Depleted Oil Field	Salt Cavern		
Total storage capacity	tH_2	425,000	425,000	425,000	Angeles Link Production Study
Individual storage tank capacity	tH_2 or m^3	N/A	N/A	~700 tH_2 or 10,000 m^3	National Petroleum Council[158,159]
Total storage volumes (throughput)	tH_2	~968,000	~968,000	~968,000	Angeles Link Production Study
Pressure	Bar	235	235	<5	Underground: Chen et. al.[160] Above-ground: National Petroleum Council
Fixed O&M	% of CAPEX	1.0%	1.0%	2.0%	
Power demand	kWh/kgH_2	2.2	2.2	10.0	
Storage CAPEX (including cushion gas)	US$MM	$3,052	$12,328	$17,756	
Compressor/Liquefier CAPEX	US$MM	$917	$917	$10,257	
Total CAPEX	**US$MM**	**$3,968**	**$13,244**	**$28,013**	

157 See Table 5 in the Design Study, Configuration A, single run scenario; also referred to as Scenario 7 in table 4 in the same study.
158 National Petroleum Council. https://harnessinghydrogen.npc.org/.
159 The capacities assumed for above-ground storage were reported as commercially available by developers. Larger storage vessels are in development: a large-scale LH_2 tank, with a capacity ranging from 20,000 to 100,000 cubic meters, is both feasible and cost competitive at import and export terminals. See: https://www.mcdermott-investors.com/news/press-release-

7.5.2. Considerations for T&D with In-Basin Production Transmission Technology

The T&D with in-basin hydrogen production alternative assumed a new build electric transmission and distribution system (500kV AC transmission system) in addition to the associated electric system appurtenances (such as step-up/step-down electric transformer substations required at the point of offtake of electricity and at the point of receipt) and associated high voltage transmission losses. In response to stakeholder feedback during the PAG meeting in June 2024, considerations of the potential to transmit electricity via High Voltage Direct Current (HVDC) system instead of High Voltage Alternating Current (HVAC) transmission system were added to this analysis.

Several factors may influence the decision to move energy as molecules (hydrogen) or electrons (electricity), including regionality constraints, siting/land-use restrictions, environmental implications, energy throughput considerations, techno-economics, and the transport distance. According to the LA100 Study, "resources that use renewably produced and storable fuels…[are] a key element of maintaining reliability at least cost given…challenges in upgrading existing or developing new transmission."[161] The HVDC systems will require additional electric conversion investments to convert electricity from direct current (DC) to alternating current (AC) at the point of receipt to utilize the energy for hydrogen production at scale.
California has roughly 33,000 miles of electrical lines, with PG&E operating 57%, Southern California Edison (SCE) 16%, San Diego Gas & Electric (SDG&E) 6%, local utilities 18%, and government 3%.[162] HVAC systems account for the majority of the high voltage transmission network in California.[163] The only HVDC transmission line in the California high voltage transmission system is the undersea Trans Bay Cable in San Francisco Bay, which went into service in late 2010.[164] The high-voltage TransWest Express Transmission Project (to meet the energy demands in the western United States) is currently under development and includes 732 miles of high-voltage transmission infrastructure divided into two systems: a 3,000 MW

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details/2021/Shell-Led-Consortium-Selected-by-DOE-to-Demonstrate-Feasibility-of-Large-Scale-Liquid-Hydrogen-Storage/default.aspx.
[160] Capacity Assessment and Cost Analysis of Geologic Storage of Hydrogen: A Case Study in Intermountain-West Region USA. Chen, et al, 2024.
[161] https://www.nrel.gov/docs/fy21osti/79444-6.pdf (p. 3, footnote 2).
[162] California Power Lines, Hydroelectric Power, and Natural Gas
[163] https://ia.cpuc.ca.gov/environment/info/ene/mesa/Docs/A1503003%20ED-SCE-03%20Q.01.a%20Attachment-CEC-700-2014-002%20(Part%202).pdf.
[164] Ibid.

HVDC segment with terminals near Sinclair, Wyoming, and Delta, Utah, and a 1,500 MW HVAC segment from the Utah terminal to southern Nevada.[165]

For the purpose of this study, the T&D with in-basin hydrogen production alternative focused on the 500kV AC transmission system as the default technology of choice to enable system and operational compatibility with the California's predominantly HVAC electric grid system to help meet the reliability and resiliency requirements.

[165] Ibid.