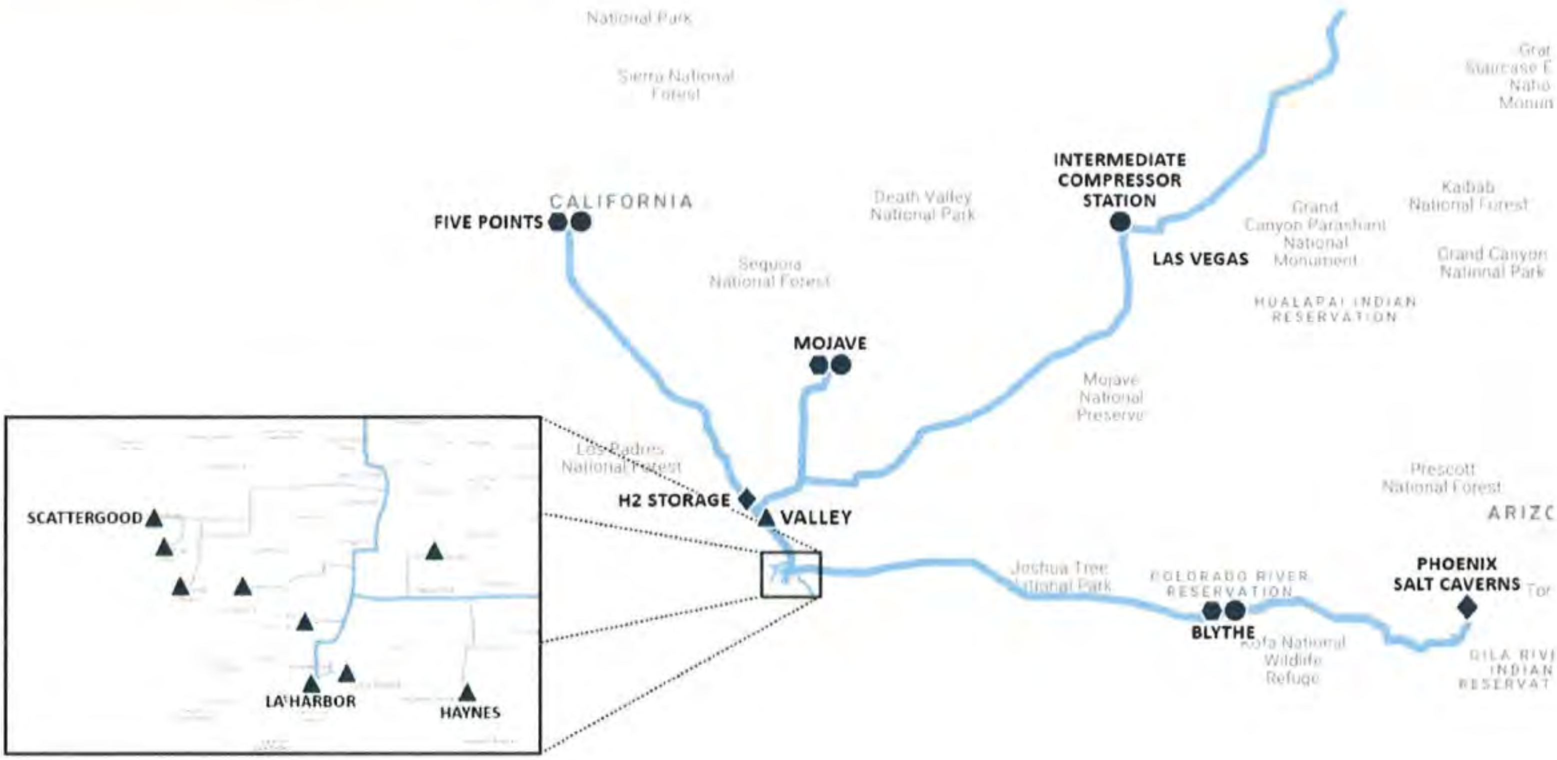
Hydrogen Pipeline Study Phase 2

Project Report



PREPARED FOR

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Revision Summary

Date	Revision	Approved	Reviewed
06/29/22	0	[redacted]	[redacted]

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Executive Summary

This conceptual, high-level prefeasibility study was commissioned by SoCalGas to explore the potential for large-scale development of hydrogen infrastructure to serve southern California. The study provides engineering and supporting information to assist SoCalGas in preliminary assessment of the logistics and economics of potentially transporting green hydrogen via pipeline to demand centers in the Los Angeles Basin and surrounding areas. The study provides an overview of the major components and a potential operating concept for such a system from an engineering and overall systems perspective. Although the primary purpose of the study was to assess transportation, storage, and delivery of green hydrogen, the study included production of green hydrogen in order to determine the range of operating requirements for the pipeline, compression, and storage aspects of the pipeline transportation system. This production of green hydrogen is expected to be carried out by third parties and not by SoCalGas.

Importantly, this preliminary study builds on SPEC Service's Phase I Report, which was also conducted as a high-level, conceptual study. The SPEC Phase I Report was conducted entirely at a "desk-top level" and did not take into account a variety of factors, including SoCalGas's plans to deliver pure green hydrogen through the Angeles Link Project, announced on February 17, 2022. Given the conceptual nature of both the Phase I and this Phase 2 report, it is critical that further study be conducted before any conclusions are drawn regarding the resources necessary for the feasibility, costs, or impacts of a large-scale hydrogen transmission system.

In this Phase 2 Report, four conceptual renewable energy and hydrogen production sites identified by SoCalGas were considered for producing up to [redacted] of green hydrogen. These hypothetical production centers are located in California near Five Points, Mojave, and Blythe, and one center is located near Delta, Utah. Potential geological storage sites near Delta UT, Phoenix AZ, and Castaic, CA were included for analysis of potential seasonal, longer term storage. Six theoretical configurations of hydrogen production, storage, and pipeline transportation systems were assessed at three levels of hydrogen demand, [redacted], [redacted], and [redacted]. Three of the studied systems include one of the California production centers while storing hydrogen at a local gas/oil field near Castaic, CA. A fourth hypothetical system includes a Delta, Utah production center, with hydrogen storage in proposed salt caverns near Delta, Utah. The fifth system studied in this report includes a Mojave production center with a pipeline to storage at the proposed Delta salt caverns. The sixth modeled system includes a Blythe production center with a pipeline to potential salt cavern storage near Phoenix, Arizona. The underground storage of hydrogen would support the continuous supply of hydrogen throughout the year and during seasonal fluctuations in hydrogen production and demand.

Costs for the conceptual system are separated by major components: production, pipeline, compression, and storage. The largest CAPEX cost may be the hydrogen production center, providing both solar power generation and hydrogen production, which accounts for approximately [redacted] of the estimated cost of the system, depending primarily on production volume. For the three [redacted] systems with Castaic area storage, hydrogen production is [redacted] of the total, pipeline and compression facilities is [redacted] and storage is [redacted] For the lower volume cases, production and compression costs generally go down proportionately, but pipeline and storage costs do not. The [redacted] case total cost, as modeled, is approximately [redacted] of the [redacted] case total cost, and the [redacted] case, as modeled, total cost is generally [redacted] of the [redacted] case total cost. Major operating costs include production, water supply, compression, and seasonal storage (oil/gas reservoir).

Renewable Energy and Hydrogen Production

The primary components of the green hydrogen production system are large scale renewable solar power generation, electrolyzers for separating hydrogen from water, battery storage to support system operation, and water supply and treatment.

This prefeasibility study is based on generating all renewable power for the system using PV solar panels. As an indication of scale, land required for solar panels under these modeling scenarios ranged from [redacted] square miles (lowest of the [redacted] systems) to [redacted] square miles (highest of the [redacted] systems). Wind power may ultimately provide supplemental power, but was not included in the basis of this initial assessment. Solar power generation rate varies on a daily and seasonal basis, and due to weather conditions (cloud cover). Potential renewable power production at each modeled site was based on the Typical Meteorological Year (TMY) data from the National Renewable Energies Laboratory (NREL), which is based on hourly solar irradiance measured over multiple years. Solar capacity factor data varied between the sites studied by up to 14%. Due to the large scale of power used by the electrolyzers, ranging from [redacted] for the production levels assessed, transmission of renewable power from other sources was not included in this study. However, connection of the production center facilities to a major power transmission system should be included in further studies to allow import of renewable energy in non-solar hours and facilitate potential 24/7 compression or other continuous process applications at that site.

This prefeasibility study is based on Proton Exchange Membrane (PEM) electrolyzers being able to produce hydrogen at pressure (assumed [redacted] psig) to reduce compression, and with the capability to be turned down to 0% each night to limit use of batteries and imported power. The study was based on generating all needed power with on-site solar panels, and using batteries only as required for incidental power and incremental night-time hydrogen compression power.

A continuous volume of water may be needed for hydrogen production. A high level assessment of major water sources confirmed that water supply is limited at the preliminarily studied production centers and that solutions should be developed to reliably supply water for electrolysis. Demineralized water volumes modeled range from [redacted] million gallons per day (MGD) for the hypothetical [redacted] case to [redacted] MGD for the [redacted] case studies. The estimated volumes of potable or recycled water needed to produce demineralized water [redacted] times and [redacted] times, respectively, these volumes of demineralized water.

Onsite Compression and Storage

Reciprocating compressors are provided at the modeled hydrogen production site to compress hydrogen from electrolyzer output pressure to up to [redacted] psig, sufficient for shipping to the transmission pipeline system and simultaneously to on-site storage. Under the Phase 2 modeling scenarios, the compressors are powered by the solar power generation system, using less than 2% of the power being used for electrolysis. Configuring compressors for the varying conditions required by this system will be challenging but feasible, and has not been considered in this study.

The hydrogen production design rate was modeled to be approximately 2.7 times the average annual production rate, as hydrogen is produced only when solar power is being generated, and solar energy production is substantially less in winter than summer. Hydrogen compressors must therefore also have about 2.7 times the capacity required for the average annual production rate, in order to be powered directly by electrical energy produced on site.

Some form of hydrogen storage should be provided in the system to accommodate this daily on-off cycle of hydrogen production and allow for a more constant rate of transportation, delivery, and incremental seasonal storage. [redacted], [redacted]. For the purposes of this prefeasibility study, high pressure gas storage of hydrogen is included at the production site for most cases, storing excess hydrogen produced during the day and providing a clean stream of hydrogen to the transportation system during non-producing hours. This on-site storage included varies with system configuration and production rate, and is estimated to cost approximately [redacted] the total cost of the system. For this study, the on-site pressure storage may include up to [redacted] miles of [redacted] pipeline-type storage operating in the range of [redacted]

Transportation and Seasonal Storage

Transmission pipelines are provided from the production/compression sites to geologic seasonal/backup storage and to demand centers in the Los Angeles Basin. The system configurations for each of the six systems studied are presented in the study. In most cases, a single pipeline is sufficient for hydrogen transport from point to point. At the proposed system flow rates, [redacted] transmission pipelines, [redacted] inch diameter, may be required to move the hydrogen from production centers to potential demand centers. In addition to compression at the production centers, the two Delta salt cavern options may require an intermediate compression facility.

Storage is a critical factor in the system operation. Large-scale storage may be required if the system is to provide continuous supply despite seasonal production rate variation and weather induced interruption in hydrogen production. Salt cavern storage near Delta, Utah is a viable storage option, located approximately 600 miles from Los Angeles. Salt formations are present in the area of Phoenix, Arizona and may be suitable for hydrogen storage development. No research was performed on either of these salt cavern options and the cost estimates in this study do not include CAPEX and OPEX costs for salt cavern storage or for compression and other equipment that would be associated with them.

This study included a high level assessment of oil and gas reservoirs in southern California for possible conversion to hydrogen storage. The hydraulic assessment and cost estimates are based on the development of a suitable reservoir in the vicinity of Castaic. [redacted]. Storage of hydrogen at scale in underground reservoirs is the subject of considerable research and study to identify the potential challenges and risks and how to overcome or mitigate them. [redacted]

[redacted], the estimated storage field costs included plugging and abandoning/re-abandoning existing wells, new hydrogen injection and withdrawal wells, flow lines, and controls, injection compression, gas/liquid separation, dehydration, and membrane separation of hydrogen from produced hydrocarbon and other gases, and an allowance for increased power supply to the site.

Demand Centers

This prefeasibility, high-level study is based on transporting green hydrogen by pipeline to demand centers in the Los Angeles Basin, including Los Angeles Department of Water and Power (LADWP) power plants, Los Angeles area industries (including refineries), and transportation centers such as the Ports of Los Angeles and Long Beach and in the LA Basin.

To balance seasonal and daily fluctuations in hydrogen production with seasonal and daily fluctuations in demand, the system hypothetically developed included pipelines large enough to transport hydrogen at peak flow rates, on-site high pressure storage for daily fluctuations and off-site storage for seasonal storage. The fluctuation in demand was driven largely by the projected variable demand from the LADWP power plants which were assumed to be a major demand center. A change in demand center assumptions, such as shifting demand to a more constant user such as Los Angeles industries, may affect the sizing of the pipelines and high pressure storage needed. For future phases of analysis and development, additional detail on the specific requirements and characteristics of different hydrogen users will be needed in order to plan and develop a system that meets their needs.

Requirements for Future Study

With the large scale of these facilities, each aspect of the system will require extensive analysis, planning, and engineering. The primary technical system issues identified in this prefeasibility study to be resolved include:

- Water supply
- Hydrogen storage (assessment of geologic storage and storage needs)
- Demand, delivery, and service requirements, including power plants, industry, and heavy vehicle fuel supply
- Pipeline specifications and operating requirements relative to pressure cycling
- Requirements for backup and resilience

1.0 Introduction

1.1 Purpose

This conceptual, high-level prefeasibility study was developed for SoCalGas to explore the potential for development of hydrogen infrastructure at scale and to determine whether there is a feasible business case to pursue such development. This prefeasibility study provides engineering and supporting information to assist SoCalGas in planning future studies to assess the practical and economic viability of producing green hydrogen in large quantities and transporting it via pipeline to demand centers in the Los Angeles Basin and surrounding areas. This production of green hydrogen is expected to be carried out by third parties and not by SoCalGas.

Three possible levels of future demand ([redacted], [redacted] and [redacted] of hydrogen) have been considered based on available energy consumption data and guidance from SoCalGas.

The major components of this prefeasibility study include the following:

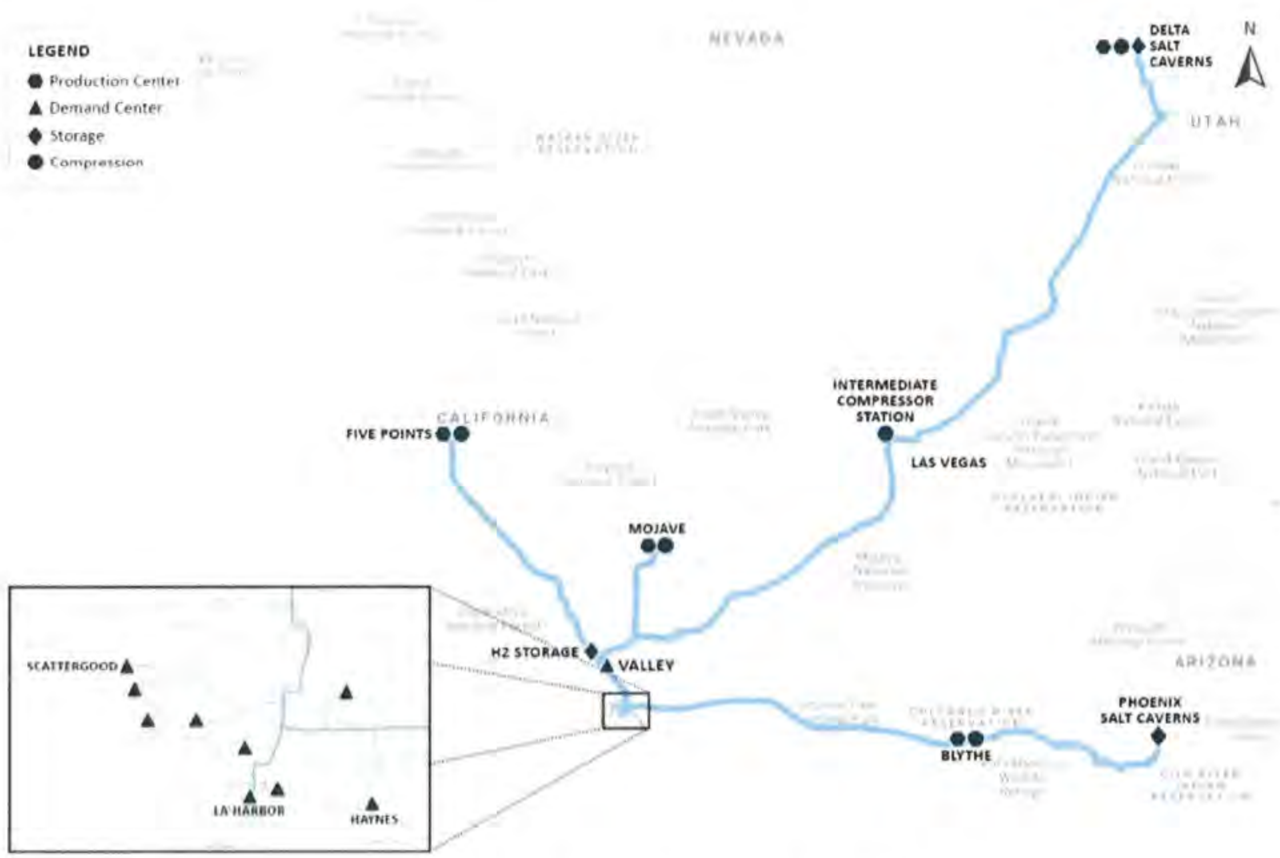
- Establishment of [redacted], [redacted], and [redacted] Demand scenarios for green hydrogen.
- Assessment of green hydrogen production at 4 potential production centers (3 in California and 1 in Utah).
- Assessment of new hydrogen transmission pipelines from production centers to potential major demand centers.
- Assessment of potential hydrogen storage options for large quantities of green hydrogen.
- Assessment of potential water resources related to the production of green hydrogen.
- Development of cost estimates related to the production, transportation, and storage of hydrogen.

A previous Phase 1 conceptual study was completed by SPEC Services and is used as the basis of this Phase 2 study. Separate studies and reports have been prepared to preliminarily, and at a high-level, study the renewable energy/hydrogen production system, the hydraulic analysis and overall system planning, potential geologic storage in an oil/gas reservoir, water source (for hydrogen production), environmental, and right-of-way/land acquisition. The hypothetical pipeline system (including compression and alternative storage assessment) is presented in this report, as well as an introduction to each of the separate reports.

This Phase 2 builds off of the conceptual Phase 1 study and provides specific refinements. For example, based on direction from SoCalGas, hydrogen for blending into the natural gas system is not considered.

1.2 Locations and Pipeline Routing

Four conceptual production areas identified by SoCalGas have been preliminarily evaluated: (1) Five Points (southwest of Fresno), (2) Mojave, (3) Blythe in California, and (4) a location near the LADWP Intermountain Power Plant in Utah. For the purposes of providing a workable system upon which to base this study, it has been assumed that sufficient on-site pressurized storage will be installed at each production site (such as in the form of high pressure pipeline/piping) to deliver hydrogen to the pipeline system at a relatively uniform rate throughout each day. Conceptual pipeline routes from each production center location to the Los Angeles Basin are shown on the map below, along with two potential storage locations. The storage location options include salt caverns near Delta, Utah and oil/gas reservoir storage development in the Castaic area of Los Angeles.



For these cases, it was assumed that all hydrogen would be generated at a single site.

This study also assumes construction of all new facilities for a dedicated hydrogen system. Consideration of any existing pipelines or the staged development from a lower demand case system to a higher demand system and capacity is not included in this study.

1.3 Limitations of Study

The results of this prefeasibility study are based on a high level assessment of the overall system and consideration of siting in southern California. The actual production, transportation, and storage of green hydrogen at the scale discussed in this report has not been completed domestically or internationally. This prefeasibility, high-level study will discuss the major technical aspects of producing, storing, and transporting large quantities of green hydrogen.

Costs are considered order of magnitude, with the expectation that the total project cost would be not less than the estimated cost minus 50% or more than the estimated cost plus 100% (-50% to +100%). The study has largely relied on parametric and factored costs in developing the cost estimates. Per the Association of the Advancement of Cost Engineering (AACE), the level of engineering associated with an order of magnitude (or class 5 estimate) is approximately 1% to 15%. Preliminary material and construction costs are estimated based on representative costs for similar equipment, material and construction. Construction costs are parametric or factored based on costs for similar but smaller scale projects. Demand projections provided in the report are based on available data and guidance from SoCalGas and are used solely for developing basis of design scenarios. Actual projections will require a detailed study of individual customer demand requirements, detailed long term projections, and assessment of environmental, state and local regulations.

1.4 Appendices

Individual preliminary pre-feasibility reports completed by subject matter experts are included as appendices to this summary report for more detailed information. These individual pre-feasibility reports are listed in the table below summarizing the subject matter, latest revision, phase completed, and consultant.

Table 1: Reports Included as Appendices

Study Scope	Revision	Consultant
Hydraulic Analysis Report, Hydrogen Pipeline Study Transportation System, 8143A-M-001	Revision 1, 6/14/22	SPEC Services, Inc.
Hydrogen Demand Assessment Report	8/31/21 (Completed in Phase 1)	Strategen Consulting
Hydrogen Production Assessment Report	Revision B, 9/30/2021 (Completed in Phase 1)	Technip Energies
Assessment of Underground Storage In Oil and/or Gas Reservoirs Report	Revision 1, 10/1/2021 (Completed in Phase 1)	InterAct PMTI
Right-of-way Assessment Report	Revision 1, 9/17/21 (Completed in Phase 1)	Paragon Partners
Conceptual Pipeline Permit Assessment, Mojave	8/27/21 (Completed in Phase 1)	D. Edwards, Inc. and Rincon Consultants, Inc.
Conceptual Pipeline Permit Assessment, Delta	9/2/21 (Completed in Phase 1)	D. Edwards, Inc. and Rincon Consultants, Inc.
Conceptual Pipeline Permit Assessment, Whitewater & Blythe	9/3/21 (Completed in Phase 1)	D. Edwards, Inc. and Rincon Consultants, Inc.

Conceptual Pipeline Permit Assessment, Five Points	9/10/21 (Completed in Phase 1)	D. Edwards, Inc. and Rincon Consultants, Inc.
Water Supply Analysis, Mojave	Revision 1, 9/14/21 (Completed in Phase 1)	D. Edwards, Inc. and Rincon Consultants, Inc.
Water Supply Analysis, Delta	9/21/21 (Completed in Phase 1)	D. Edwards, Inc. and Rincon Consultants, Inc.
Water Supply Analysis, Whitewater & Blythe	9/30/21 (Completed in Phase 1)	D. Edwards, Inc. and Rincon Consultants, Inc.
Water Supply Analysis, Five Points	9/30/21 (Completed in Phase 1)	D. Edwards, Inc. and Rincon Consultants, Inc.
Analysis of Major Pipeline Precedence	8/27/21 (Completed in Phase 1)	D. Edwards, Inc. and Rincon Consultants, Inc.

2.0 Design Basis

2.1 Demand Scenarios

Demand for hydrogen in the Los Angeles Basin will be affected by the course of future developments, including potential implementation of bulk hydrogen supply explored in this study. This study assumes hydrogen delivery to power plants, transportation centers at ports, and industries, and to additional locations for distribution to supply vehicle fuel. Power plant hydrogen demand is likely to vary by time of day, by season (higher in summer and into fall), and by periods of very hot weather. Power plants need a supply that is uninterruptible or may have to provide their own local storage if available. Refineries use substantial volumes of hydrogen now and could benefit from green hydrogen supply. However, they currently have only grey hydrogen supply and other currently more economical options. Hydrogen is projected to increasingly replace diesel fuel for trucking, as it becomes economical and the reliability of supply improves. Regardless of the final users of the hydrogen, this study illustrates the requirements for a large-scale hydrogen production and supply system, provides an order-of-magnitude cost estimate, and identifies major considerations.

A detailed market driven prediction of hydrogen demand is outside the scope of this report and would require an in-depth study and survey of potential end users, regulations, and other market factors. A detailed summary of the demand scenarios assumed for this prefeasibility study is included in Table 2.

Table 2: Scenario 7 - SoCalGas Requested Hydrogen Demand Case

Demand Center Description	[redacted] Case		[redacted] Case		[redacted] Case	
	Volume (Tons H2/Year)	Description	Volume (Tons H2/Year)	Description	Volume (Tons H2/Year)	Description
Power	[redacted]	Valley, Haynes, Scattergood, Harbor Only	[redacted]	Valley, Haynes, Scattergood, Harbor Only	[redacted]	Valley, Haynes, Scattergood, Harbor Only
Transportation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Industrial	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Demand, Tons H2/Year	[redacted]		[redacted]		[redacted]	
Requested Range	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Notes:

1. For purposes of this study, all of the demand except for power plants was assumed to be at a constant rate.
2. For the four power plants included in this study, actual power production for each plant vs. time was obtained from publicly available power generation data for the year 2019. Source: 2020 California Gas Report Joint Utility Biennial Comprehensive Filing, Page 143.
3. [redacted]

2.2 Project Team

Due to the many components associated with this study, a team of consultants was assembled to make full use of expertise in specific fields. This approach was considered appropriate considering the wide variety of subject matter expertise required to assess the system, develop costs, conclusions and recommendations. The team and their specific scope are as follows:

Table 3: SoCalGas Hydrogen Pipeline Project Consultant Team

Scope	**Consultant**	[redacted]
Prime Contractor and Project Lead	SPEC Services, Inc.	[redacted]
Green Hydrogen Production Assessment and Development	Technip Energies and Strategen Consulting	[redacted]
Hydrogen Storage – Underground	InterAct	[redacted]
Water Resources	D. Edwards, Inc. and Rincon Consultants, Inc.	[redacted]
Pipeline Transportation System	SPEC Services, Inc.	[redacted]
Pipeline Transportation System – Environmental	D. Edwards, Inc. and Rincon Consultants, Inc.	[redacted]
Pipeline Transportation System – Right-of-Way	Paragon Partners	[redacted]
Pipeline Transportation System – Cost Estimating	Campos EPC and SPEC Services, Inc.	[redacted]

2.3 System Flow Diagrams

The scale of hydrogen production consists of many components. At this prefeasibility level of study, focus was dedicated to sizing and estimating the major components and system as a whole. In reality any of the major components discussed and estimated in this prefeasibility study would typically be considered a major capital project on its own. The following is a brief description of each part of the hydrogen system. Additionally, a simplified flow diagram is provided showing how these major components are connected on a system wide basis.

- Green hydrogen production consisting of photovoltaic cells, electrolysis and battery storage systems located at the conceptual production centers;
- Water source for use in production of hydrogen by electrolysis;
- Hydrogen compression and intermediate compression;
- Transmission and distribution pipelines from the production centers to the demand centers; and
- Hydrogen storage.

Below is a listing of the system numbers and system names referenced in this report:

Table 4: System Numbers and Names

System 1	Five Points Production
System 2	Mojave Production
System 4	Blythe Production
System 5	Delta Production
System 6	Mojave Production with Delta Pipeline
System 10	Blythe Production with Phoenix Pipeline

In the Phase 1 pre-feasibility report, these systems were referred to as "demand" systems rather than "production" systems that is now used in this Phase 2 report. Systems 4, 7, 8, and 9 represent other systems that were studied in Phase 1 and are no longer considered in this Phase 2 study.

In total, six conceptual systems were assessed in this Phase 2 prefeasibility study. Three systems included production in California with storage in the Castaic area (Systems 1, 2, and 4), a fourth system included production and storage near Delta, Utah (System 5), a fifth system included a hybrid combination of the Mojave production and Delta pipeline and storage system (System 6), and a sixth system included a hybrid combination of the Blythe production and Phoenix pipeline and storage system (System 10). The hybrid Systems 6 and 10 were included to consider other potential options as reservoir storage closer to the LA Basin requires additional assessment.

These systems are summarized in the following figures. For total pipeline mileage refer to tables 13A, 13B and 13C in section 6.

2.3.1 System 1

The modeled Five Points production system includes production center at Five Points, underground storage, transmission lines to Los Angeles Basin, and [redacted] distribution lines to the demand centers.

FIGURE 1A, SYSTEM 1: FIVE POINTS PRODUCTION SCENARIO OVERALL FLOW DIAGRAM

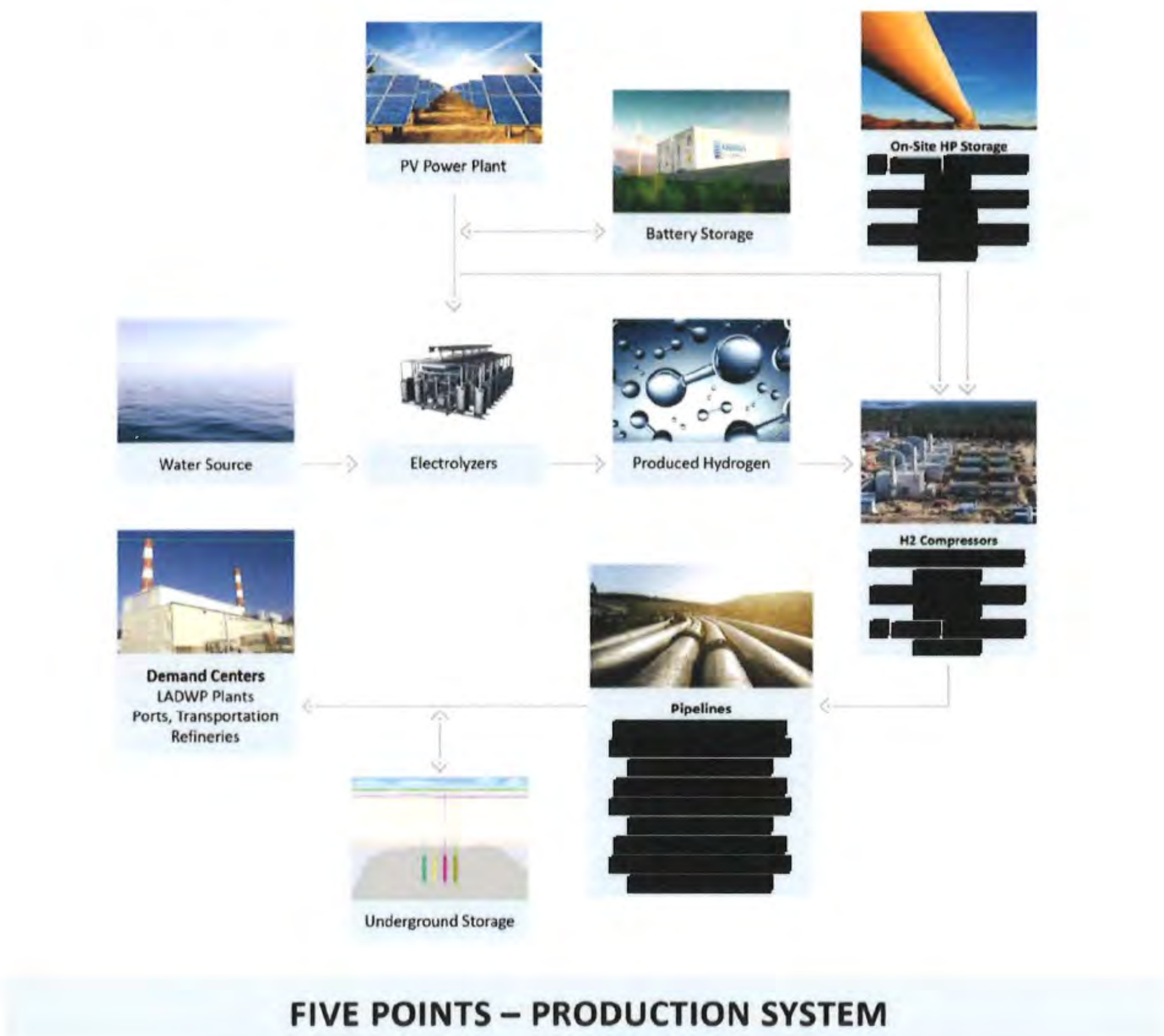
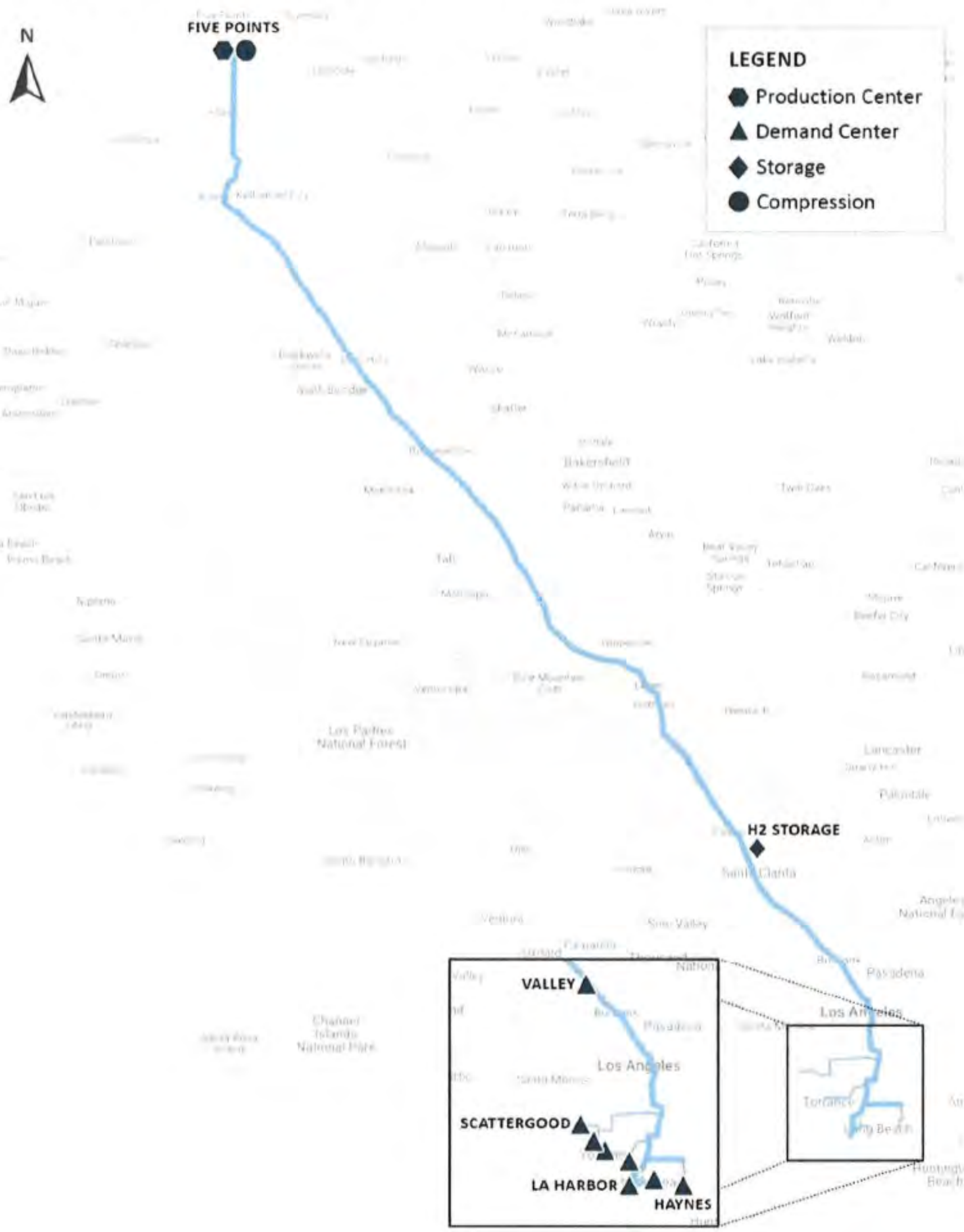


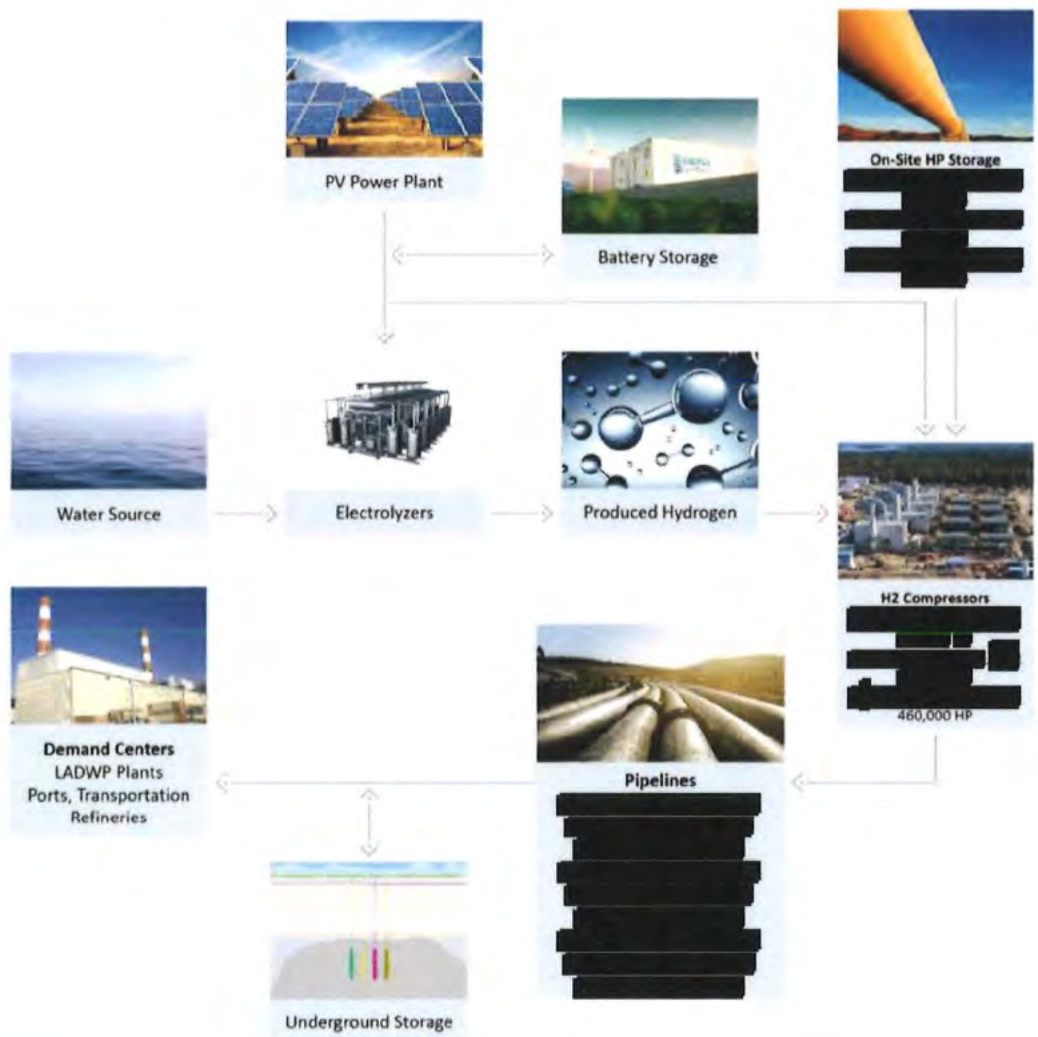
FIGURE 1B, SYSTEM 1: FIVE POINTS PRODUCTION SCENARIO OVERALL SYSTEM MAP



2.3.2 System 2

The modeled Mojave production system includes production center at Mojave, transmission lines to Los Angeles Basin, underground storage, and [redacted] distribution lines to the demand centers.

FIGURE 2A, SYSTEM 2: MOJAVE PRODUCTION SCENARIO OVERALL FLOW DIAGRAM



MOJAVE – PRODUCTION SYSTEM

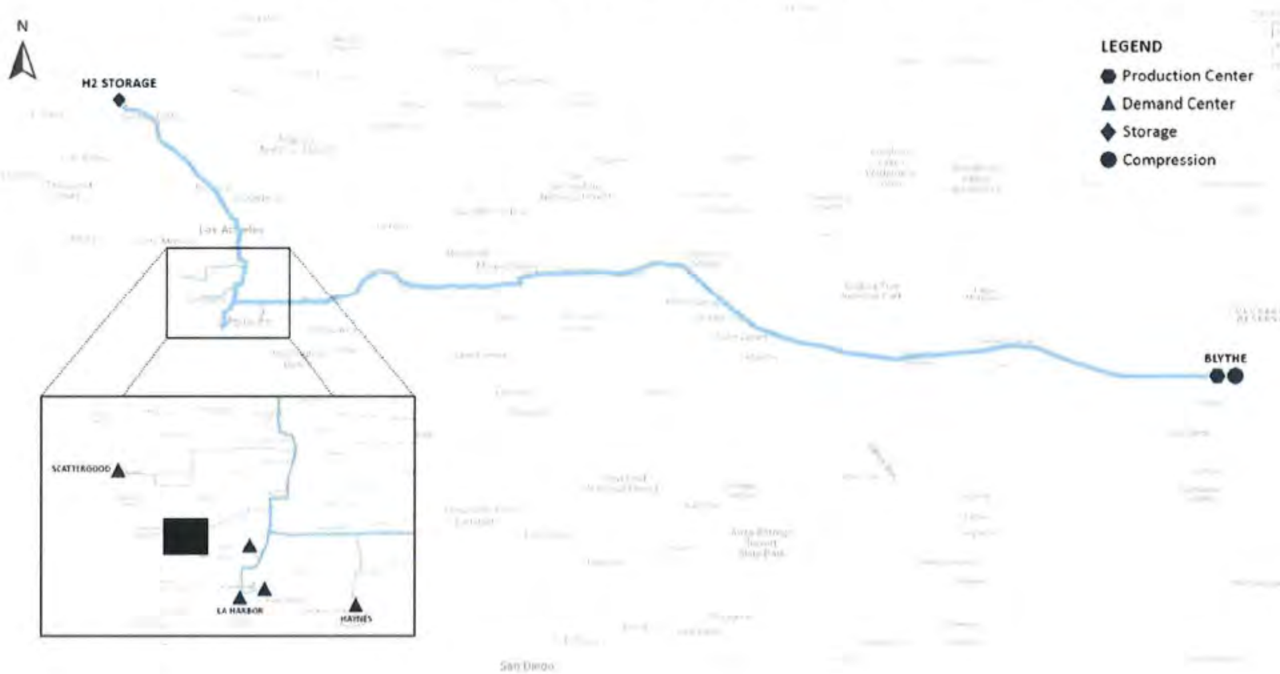
FIGURE 2B, SYSTEM 2: MOJAVE PRODUCTION SCENARIO OVERALL SYSTEM MAP

2.3.3 System 4

The modeled Blythe production system includes production center at Blythe, transmission lines to Los Angeles Basin, underground storage, and [redacted] distribution lines to the demand centers.

FIGURE 3A, SYSTEM 4: BLYTHE PRODUCTION SCENARIO OVERALL FLOW DIAGRAM

FIGURE 3B, SYSTEM 4: BLYTHE PRODUCTION SCENARIO OVERALL SYSTEM MAP



2.3.4 System 5

The modeled Delta production system includes production center at Delta, Utah, salt cavern storage, intermediate compression, transmission lines to Los Angeles Basin, and [redacted] distribution lines to the demand centers.

FIGURE 4A, SYSTEM 5: DELTA PRODUCTION SCENARIO OVERALL FLOW DIAGRAM

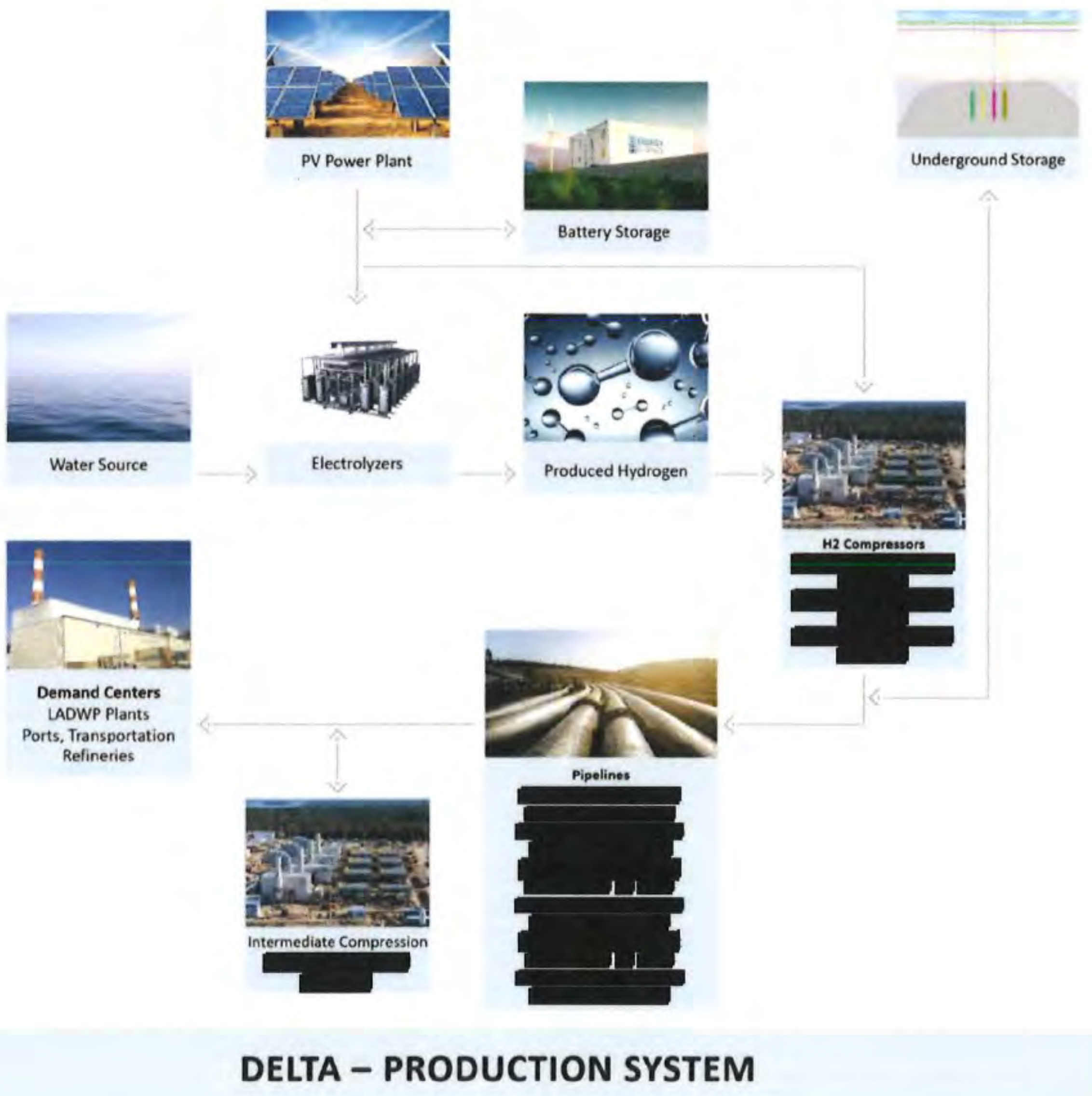
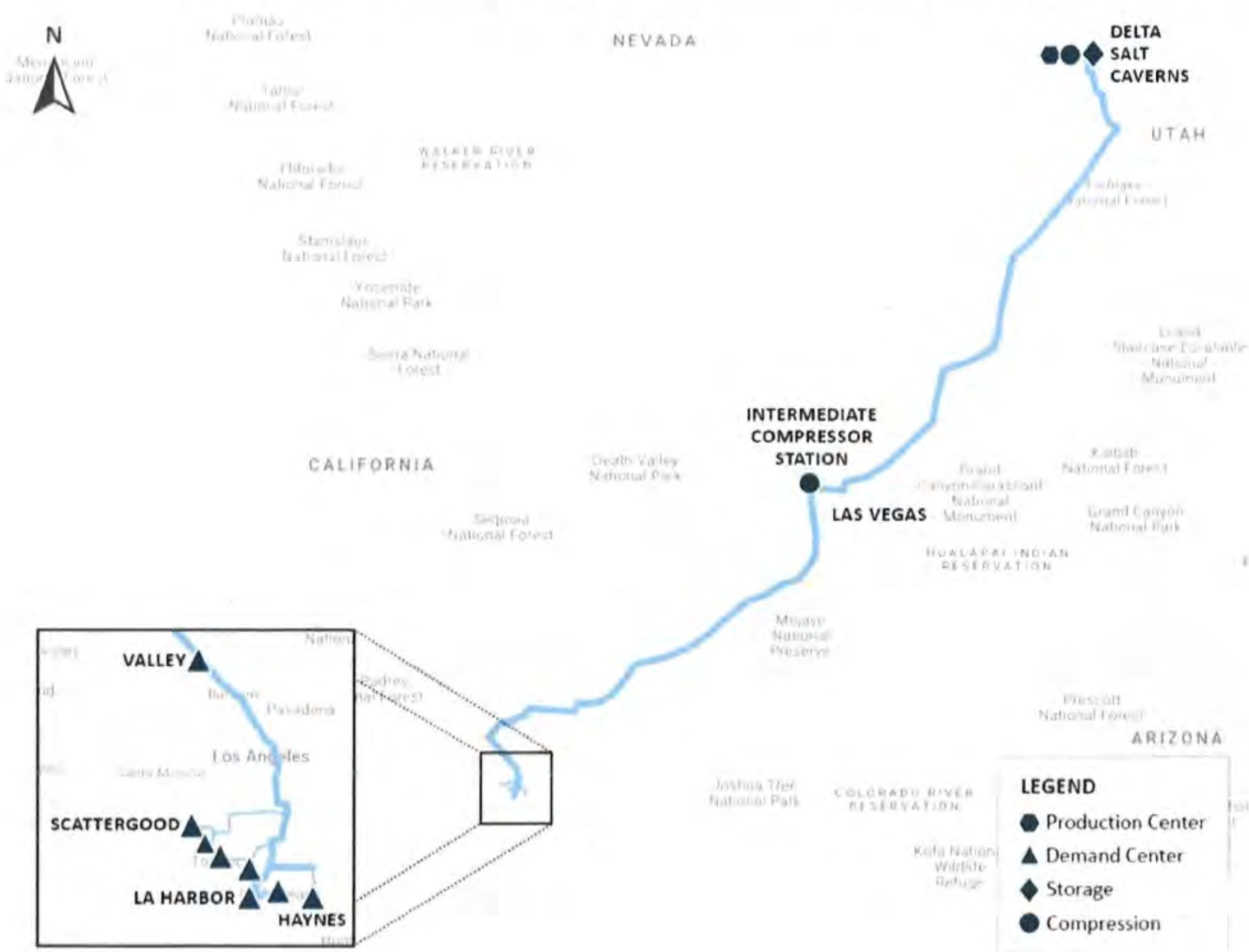


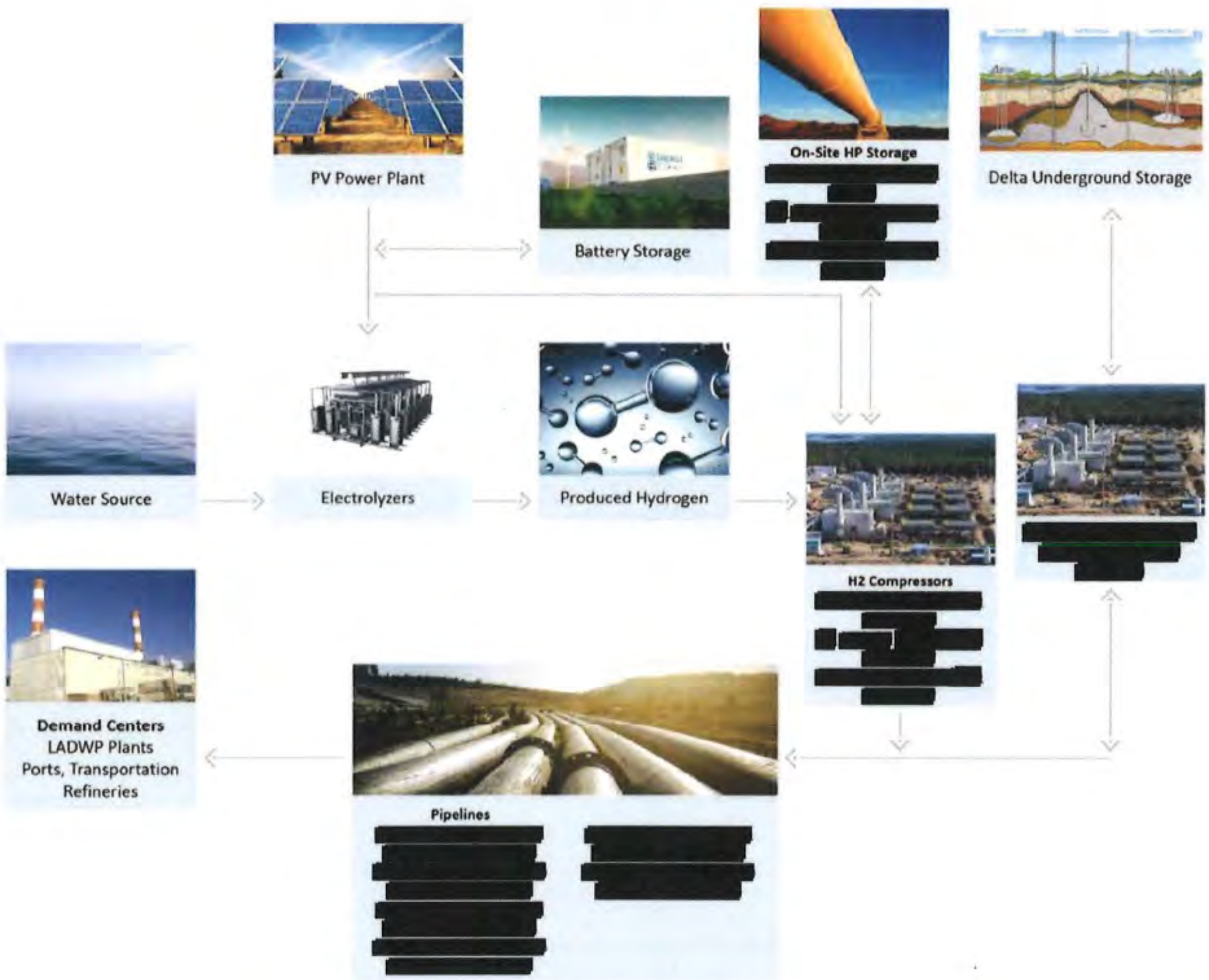
FIGURE 4B, SYSTEM 5: DELTA PRODUCTION SCENARIO OVERALL SYSTEM MAP



2.3.5 System 6

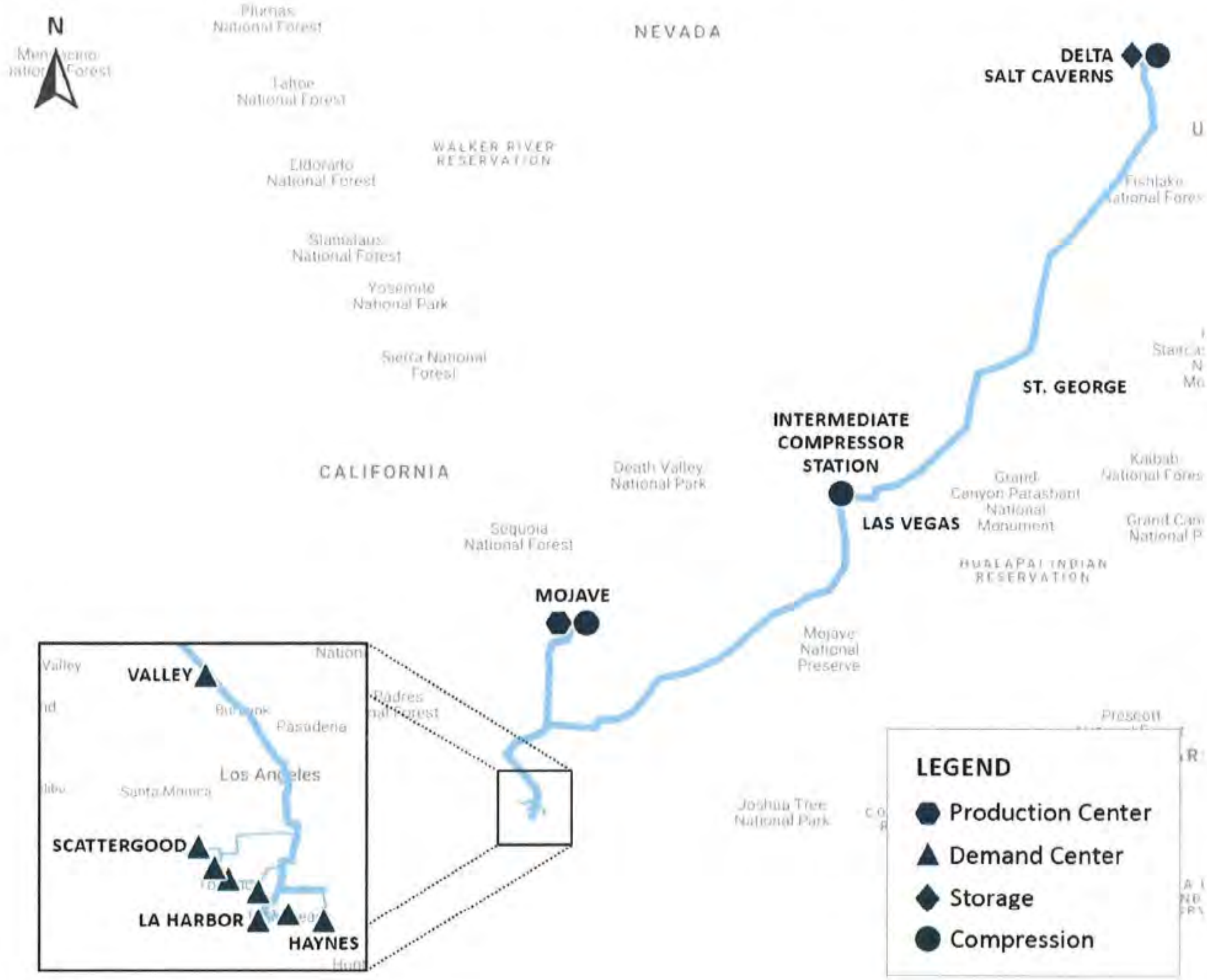
Mojave with Delta Pipeline production system, as modeled, includes production center at Mojave, salt cavern storage, intermediate compression, transmission lines to Los Angeles Basin, and [redacted] distribution lines to the demand centers.

FIGURE 5A, SYSTEM56: MOJAVE WITH DELTA PIPELINE PRODUCTION SCENARIO OVERALL FLOW DIAGRAM



MOJAVE WITH DELTA PIPELINE – PRODUCTION SYSTEM

FIGURE 5B, SYSTEM 6: MOJAVE WITH DELTA PIPELINE PRODUCTION SCENARIO OVERALL SYSTEM MAP



2.3.6 System 10

The modeled Blythe with Phoenix Pipeline production system includes production center at Blythe, salt cavern storage, transmission lines to storage and to Los Angeles Basin, and [redacted] distribution lines to the demand centers.

FIGURE 6A, SYSTEM 10: BLYTHE WITH PHOENIX PIPELINE PRODUCTION SCENARIO OVERALL FLOW DIAGRAM

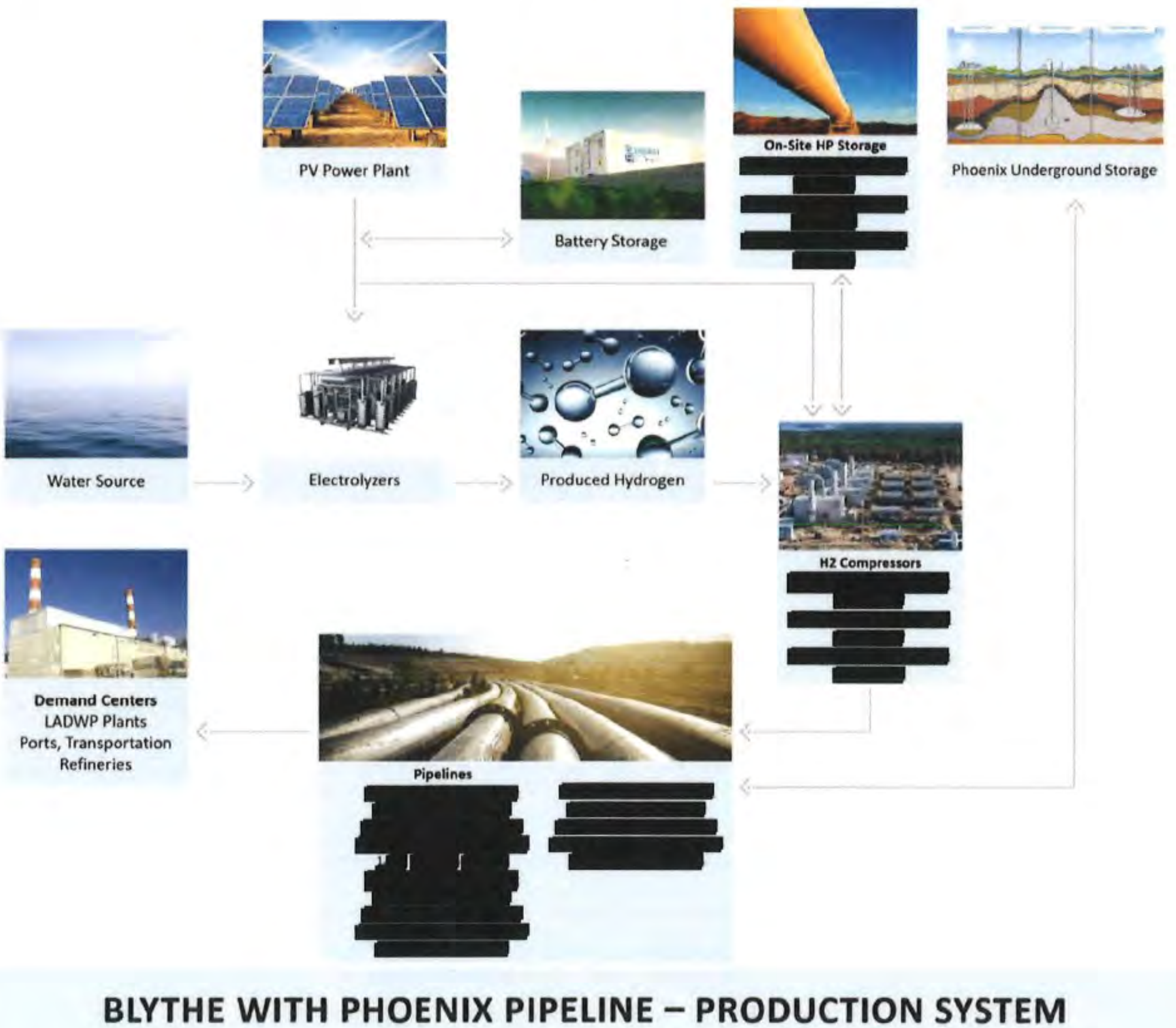
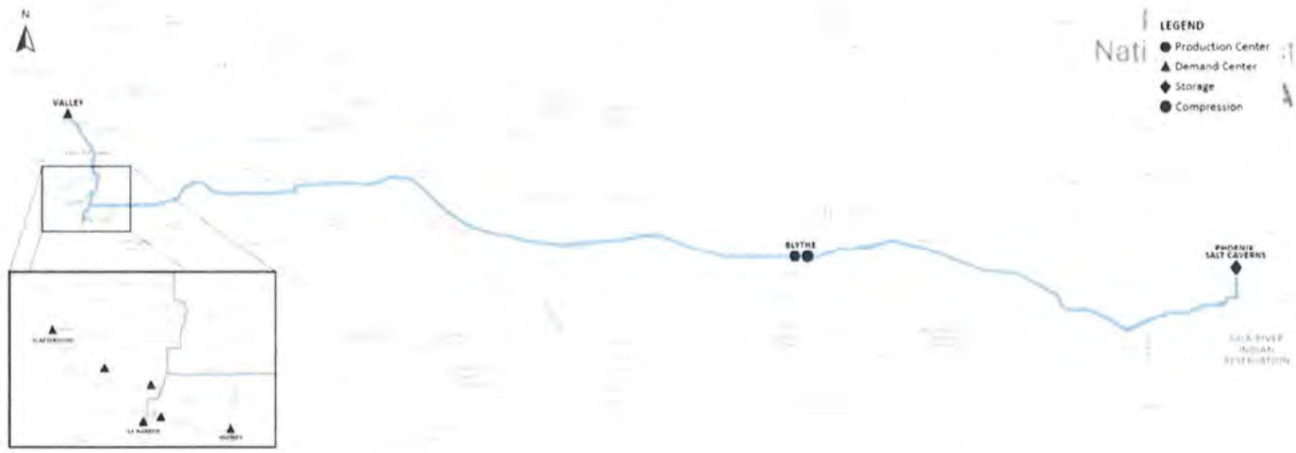


FIGURE 6B, SYSTEM 10: BLYTHE WITH PHOENIX PIPELINE PRODUCTION SCENARIO OVERALL SYSTEM MAP



3.0 Conceptual Hydrogen Production System

3.1 Green Hydrogen Production

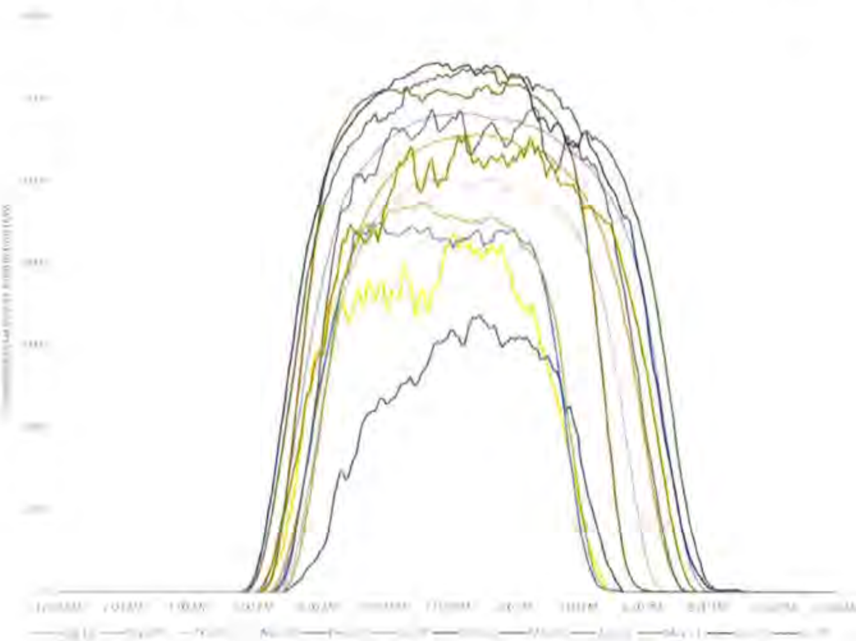
Technip Energies developed the renewable power and hydrogen production system analysis and estimates. A separate report summarizes their work and findings, which have been scaled appropriately for these Phase 2 demand and system cases.

The scope of the study included assessing power generation with both photovoltaic (PV) solar panels and wind turbines, which would be constructed solely to power electrolyzers for the production of hydrogen from water. When power is available, each electrolyzer unit operates at its design capacity to separate water into hydrogen and oxygen, with the hydrogen being captured and compressed and the oxygen released to the atmosphere. For purposes of this study, the recovery of produced oxygen for potential commercial use is not considered. If more power is generated than the total capacity of the facility electrolyzers, the excess power cannot be used and must be curtailed.

Wind turbines can generate more power as wind speed increases, potentially in excess of the capacity of the electrolyzers to use the power. Wind turbines also require substantially more land area than solar panels generating the same amount of power due to the distances required between turbines (approximately 200 acres per 5.8 MW turbine). An optimization analysis was performed for a combination of wind and solar at each of the four sites in California, with the goal of maintaining the rate of hydrogen generation within [redacted] of the average annual production rate. Under the study's model, the power generated from wind varied substantially by site, required more land than was likely to be available and suitable for this purpose, and did not result in substantial cost reduction. Although actual development may be able to implement a combination solar and wind system economically, this study continued on the basis of producing all of the renewable power using solar (PV panels).

Desert environments provide some of the most optimal conditions for solar power generation; however, the generation rate still varies widely between seasons. The following chart illustrates the relative power generation in California by solar for the year 2020.

FIGURE 7: CALIFORNIA SOLAR POWER GENERATION FOR 2020 (SOURCE: CALIFORNIA INDEPENDENT SYSTEM OPERATOR)



The capacity factor for solar power also varies somewhat between the sites. In Southern California, a solar panel can generate approximately 218% more watt-hours in a typical summer day than a winter day, due to the longer daylight hours and higher intensity of the sunlight. The average peak generation rate in summer is approximately 47% higher than the average peak generation rate in winter. The hydrogen production rate generally follows the same daily cycles as the power generation rate, and electrolyzers are either oversized and not using all of their capacity in the winter, or undersized relative to being able to use all of the summer power available at peak generation rates. These factors and equipment and operating costs are considered in the optimization analysis.

The PEM electrolyzers selected as the basis of the study can ramp up and down in capacity very quickly. Preliminary analysis followed the specifications of some manufacturers that their PEM electrolyzers must be powered at all times at a minimum 5% power level, requiring battery power when renewable power was not being generated. Other manufacturers indicated that powering down the electrolyzers fully for up to several days is acceptable, which greatly reduces the power required during the non-productive hours of the day. The projected cost of the batteries is very high, so this report and the estimates herein are based on the assumption that electrolyzers will be available that have a 0% minimum power level.

Although batteries will not be used to power electrolyzers under the modeled scenario, this report includes some batteries charged during the daytime to provide minimum power to the site and compressor power (from on-site storage to transmission pipeline) while there is no solar power production. It may be possible to connect to an external power transmission system and purchase power for this purpose, but for the purposes of this prefeasibility study batteries were assumed to be necessary for this self-contained system to operate.

To make up for the lack of hydrogen production at night, the daytime hydrogen production rate must typically be more than twice the average annual production rate. All of the hydrogen must be compressed at the rate that it is produced, and sent to pipeline for transportation or to storage. Some of the hydrogen will satisfy demand as it is produced. The balance of the production, which could be over 60% of the actual daytime production rate, must be sent to storage of some type. Optimizations were performed by Technip for the production systems using a combination of solar and wind to power the electrolyzers. This data was used in the hydraulic modeling of the pipeline and storage system by SPEC. Subsequently an optimization of Whitewater was performed based on using solar only for renewable power generation. This data was factored and used by SPEC in the hydraulic analysis for System 6. For this case, the hydrogen was assumed to be produced at a pressure of [redacted] psig and made available for shipping and/or storage as it was produced.

Analysis was performed for each production site based on a production rate of [redacted] of hydrogen production. The results of this analysis are representative and directly proportional to the three demand cases included in this study: [redacted], and [redacted] The discussion in this section on conceptual hydrogen production system applies to all demand cases, and the data from the [redacted] production rate analysis is directly proportional and was factored accordingly to provide data for these three Phase 2 demand cases. Production volumes and rates for all Systems are based on factoring the analysis of the PV only data relative to the (solar) capacity factor for each site and the assumed amount of hydrogen production to be provided by each site.

The Technip Green Hydrogen report on renewable power generation and hydrogen production provides details on these optimizations and on the program used to perform the optimizations, the basis for cost, the total costs and cost breakdown for each site (including water and land), and other details and graphics. Tables of estimated hydrogen production costs (CAPEX and OPEX) are presented in the Technip report and included in section 11.6 of this report.

The Technip "Hydrogen Production Assessment Report" is based on using the Typical Meteorological Year (TMY) time series for potential renewable power production at each site from the National Renewable Energies Laboratory (NREL) System Advisor Model (SAM). The TMY is an hourly potential energy profile created from a database of the hourly solar irradiance as measured at a given location over multiple years. It includes "typical" yearly weather phenomena, such as days with little or no potential solar production.

The technical and economic characteristics of each component were input to the Technip program. Specific details of each item are included in the hydrogen production report, but for reference below are the PV modules, batteries, and electrolyzer data:

Table 5: PV Modules Inputs	
Parameter	**Value**
Number of Modules	Optimization parameter
Footprint per module	[redacted]
Power production	[redacted]
Annual Production Decrease Rate	[redacted]
Total Investment Cost	[redacted]
Annual O&M Cost	[redacted]

Table 6: Battery Inputs	
Parameter	**Value**
Number of batteries	Optimization parameter
Storage Capacity	[redacted]
Minimum state of charge	[redacted]
Initial state of charge	[redacted]
Maximum charge/discharge rate	[redacted]
Efficiency in charge/discharge	[redacted]
Self-discharge	[redacted]
Calendar degradation of storage capacity	[redacted]
Investment Cost	[redacted]
Replacement Frequency	[redacted]
Replacement Cost	[redacted]

Table 6: Battery Inputs	
Parameter	**Value**
Annual O&M Cost	[redacted]

Table 7: Electrolyzer Inputs	
Parameter	**Value**
Number of stacks	Optimization parameter
Stack Maximum Power	[redacted]
Stack Minimum Power	[redacted]
Efficiency	[redacted]
Maximum ramp-up & ramp-down rate	[redacted]
Efficiency Decrease	[redacted]
Investment Cost	[redacted]
Replacement Frequency	[redacted]
Replacement Cost	[redacted]
Replacement Cost Annual Decrease Rate	[redacted]
Annual O&M Cost	[redacted]

The full year is simulated. For this report, no imported energy is considered and therefore all of the power must come from the PV array or battery storage. The data from the preliminary Technip analysis, which included a 5% minimum power level for electrolyzers, was adjusted based on the assumed lower, 0% minimum operating level for electrolyzers. The Technip battery storage requirement to power the electrolyzers at this minimum 5% power level was reduced to provide only power for some compression and incidental plant loads when PV power is unavailable.

The Technip program provided full technical data time series as well as economic data are available for all of the production parameters. The following figure is a series of charts depicting a typical week of power production and hydrogen output for a Whitewater [redacted] production case, based on solar power generation only (no wind). Although the quantities would scale up or down proportionately based on the required demand case, these graphs are representative of results and variation during this sample week at this site for all studied demand cases. Note that these graphs are based on the use of batteries to supply a minimum 5% power level to the electrolyzers, and are included here to represent daily solar cycle and the variability of power generation due to weather conditions. The top graph depicts the power output from the solar electrical generation plant which varies each day based on weather patterns. Summer days result in curtailed power as part of the optimization to make-up for lower winter output. The middle graph depicts the battery storage status with 100% charge during the day and nominal consumption at night. This energy storage is based on the assumptions that no external power is available to power the electrolyzers during hours of no solar power output and that the selected electrolyzers would require minimum 5% operating level. The bottom graph depicts the resulting hydrogen production during this period of time for this optimized plant configuration.

FIGURE 8: WEEKLY POWER PRODUCTION AND HYDROGEN OUTPUT

[redacted]

FIGURE 9: YEARLY POWER PRODUCTION AND HYDROGEN OUTPUT

[redacted]

A hydrogen production rate of [redacted] of hydrogen was assessed relative to power generation and hydrogen production. The results of the power generation and hydrogen production analysis were then factored to correspond with the hydrogen production rates for each of the demand cases: [redacted], [redacted], and [redacted] Pipeline system analysis and pipeline system sizes were based on these factored values for each of the demand rates.

The following table illustrates the scale of the facilities needed to produce the Demand hydrogen cases based on power generated by solar/PV only:

Table 8: Summary of Production Values			
	[redacted] of H2	[redacted] of H2	[redacted] of H2
Land Area Needed for Solar Panels:			
Five Points			
Mojave	[redacted]	[redacted]	[redacted]
Blythe			
Delta			
Potable Water (million gallon/day) Needed by Electrolyzers for Hydrogen Generation:			
Five Points			
Mojave	[redacted]	[redacted]	[redacted]
Blythe			
Delta			
Land Area for Electrolyzers:			
Five Points			
Mojave			
Blythe	[redacted]	[redacted]	[redacted]
Delta			
Installed Compression Needed to Accommodate Peak Production Rate at the Origin:			
Five Points			[redacted]
Mojave			
Blythe	[redacted]	[redacted]	
Delta			
Total Capex Generation/Production Cost Alone, Excluding Land and Compression (Billions):			
Five Points	[redacted]	[redacted]	[redacted]
Mojave	[redacted]	[redacted]	[redacted]
Blythe	[redacted]	[redacted]	[redacted]
Delta	[redacted]	[redacted]	[redacted]

Notes:

1. Demineralized and recycled water rates can be found in section 5.0.
2. Production center compressor figures do not include any compression that may be required at underground storage facilities or at any intermediate compressor stations, as that compression will vary depending on the selected configuration.

4.0 Conceptual Pipeline System Analysis

4.1 Overall Approach

Hydraulic analysis was performed for delivery of hydrogen to the Los Angeles Basin from each of the 6 systems considered in the Phase 2. Each of these systems were modeled with [redacted], [redacted], and [redacted] rate cases. These cases are illustrated and briefly described in Section 2. A hydraulic analysis report included in the appendices provides details of the analysis.

The feasibility and operability of the conceptual hydrogen pipeline system depends heavily on the ability to meet the storage needed to accommodate the daily and seasonal changes in solar power and hydrogen production rates. Hydrogen storage could include a combination of a) excess pipeline capacity allowing storage by packing/unpacking, b) remote underground storage delivered by pipeline, and/or c) "onsite" high pressure gas storage (miles of [redacted] pipe). These and other conceptual storage options are described in Section 8. This storage balanced the discrepancy between daily and seasonal hydrogen production rates (which vary based on solar power availability by day and season) and hydrogen demand rates (which vary based on energy demands of the power plants evaluated in this study) such that the annual throughput for each rate case could be delivered by each system. Surplus backup storage would be in addition to seasonal storage and would be required, but has not been considered in this study.

Hydraulic analysis included both the great variation in daily production rate and the variation in power plant demand rate. Each production site/case was analyzed to determine the number and sizes of pipelines required to accommodate the high daytime peak production rates. Initial hydraulic analysis did not include "onsite" high pressure gas storage at the production sites, and with daily peak production rate approximately 2.7 times the average production rate, pipeline transportation capacity had to be more than doubled (with additional parallel transmission pipelines) to accommodate this actual daytime hydrogen production rate. Onsite high pressure storage was included to provide "daily storage" to allow hydrogen delivery rate to the pipeline transmission system at the average production rate throughout the day, avoid oversizing the transmission pipeline system.

Once a functional system was developed for each system at the [redacted] demand rate case, the scale for each system was reduced iteratively for the [redacted] and [redacted] demand rate cases.

4.2 Production Profile

With most hydrogen being produced in the daytime due to solar availability, the rate that the compressors and pipeline system must handle during the peak production hours of the day can be 250-270% of the average flow rate (based on the all-solar, no-wind case). In other words, limiting hydrogen production to only daylight hours requires that compression capacity be 2.7 times more over a case where production could be spread throughout all hours of the day. Large volume, high pressure storage at the production area was assessed to accommodate the daily variation in production rate, as was installation of additional batteries to allow compressors to operate longer hours. [redacted]

[redacted]

4.3 Demand Profiles

Demand/delivery rate was assumed to be uniform throughout the year except for power plant demand. A demand profile was developed that provided daily variation in delivery rates based on typical power plant demand cycle. With an average delivery rate of [redacted] (MMscfh), the total demand/delivery rate that was modeled varied from [redacted] for the [redacted] rate case. This variation will require additional pressure controls to ensure that the line has sufficient downstream pressure to handle the higher flow rates for certain portions of the day. The lower rate cases reduce the uniform demands (industry, transportation, etc.) but still retained the power plants, so the resulting variation remains the same. The total demand rate varied from [redacted] and from [redacted] for the [redacted] and [redacted] rate cases, respectively.

4.4 Seasonal Storage Concepts

For the purposes of this conceptual study, a working storage volume of 12% of the annual hydrogen production rate was assumed as the minimum to accommodate the production rate variation between summer and winter. Future study of demand variation between seasons may result in reduced seasonal storage requirements, as it is possible that summer demand will be higher than winter demand, which would correspond somewhat with the higher summer PV output and hydrogen production rates. Additional working storage should be considered for backup supply and resiliency. Note that working storage does not include the initial gas charge required to prime the volume with hydrogen nor losses inherent to the characteristics of the specific formation.

For the Delta Production / Delta Storage case, all hydrogen production is specified to be relatively close to Delta, and to the salt cavern storage in Delta that is included in this case. For this case, it is assumed that cavern storage will have sufficient capacity to accommodate both daily and seasonal storage needs without exceeding operating parameters. For the other cases, large volume high pressure storage is included at the production area. The high pressure storage at the production area works with the transmission pipeline volumes for each system to maintain demand rates to the LA Basin between the daily solar production peaks.

For conceptual cases involving oil/gas reservoirs for storage (Castaic Storage options), the assumed injection rate was limited to satisfying seasonal storage needs. Daily storage would require more than double the reservoir injection rates, which would require more wells, more injection compressors, and more pipelines to transport hydrogen from production to the reservoir storage location at the higher rates. As such, for the purposes of this conceptual study, "onsite" pressurized gas storage (or near-site) has been added to all systems (except Delta Production) to store daily excess production and allow relatively steady flow of produced hydrogen to the pipeline system.

4.5 California Production Sites with Local Reservoir Storage (Five Points, Mojave, and Blythe with Castaic Storage)

The hydrogen production rate varies daily from peak daytime production to minimal night time production, and seasonally with much higher daily production rates in summer than in winter. The pipeline system and hydraulic analysis considered both daily storage requirements and seasonal storage requirements. This [redacted] demand case analysis showed that the pipeline transmission systems evaluated did not have sufficient capacity to handle the daily variation in the hydrogen production rate without additional storage. For each of these three California production sites with Castaic Seasonal Storage, a large volume of high pressure storage at each production site was used to ship hydrogen at near the average daily production rate at all hours of the day. Excess production was compressed into local hydrogen storage during the day, and then feed into the transmission line toward the LA Basin during the non-producing hours of the day.

Controls were modeled to monitor the average pipeline pressure within the LA Basin. The system would transfer hydrogen from the pipeline into Castaic storage during the summer and periods of seasonal excess production, and transfer hydrogen to the pipeline out of Castaic when actual hydrogen production rate was insufficient to meet demand. The on-site high-pressure storage at the production site was sized to reduce daily pressure cycling of the transmission pipelines and avoid same-day and reduce same season cycling into and out of Castaic storage.

This study assumed confirmation of a suitable storage reservoir in the Castaic Junction for this purpose. However, storage of hydrogen in existing gas and oil reservoirs in Southern California has not been fully studied; accordingly, additional analysis of storage options and feasibility is recommended. For the hydraulic analysis and pipeline estimating purposes, local high-pressure storage of hydrogen was assumed to be feasible with looped segments of [redacted]" pipeline within the ample production land area.

Reducing the rate case to [redacted] and [redacted] incrementally reduced both the local HP storage and transmission line scale for each system configuration.

4.6 Utah Production Site and Storage (Delta Production with Delta Storage)

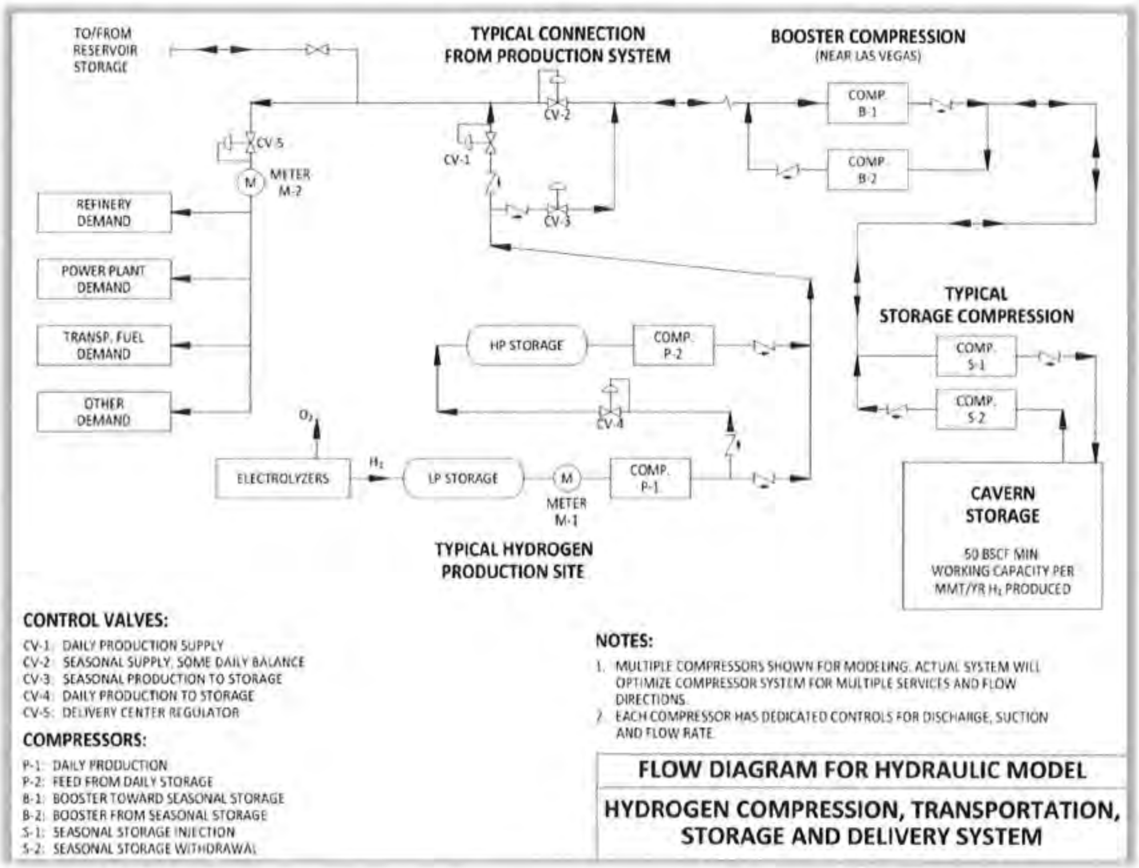
For the case of production in the Delta, Utah area, storage in multiple local salt caverns was assumed, with delivery to the Los Angeles Basin from either production or storage. The cost of such storage was not included in the scope of this study, and since it is a proven technology and the salt cavern feasibility is reported to have been studied relative to hydrogen storage, it was assumed that sufficient capacity could be provided. For this Utah production [redacted] demand case, a [redacted] pipeline with an intermediate compressor station near Las Vegas was found to be sufficient. Reducing the rate case to [redacted] eliminated the intermediate compressor station but increased the line size from Delta to [redacted] pipe. Further reduction to [redacted] reduced all transmission lines to [redacted] pipe into the LA Basin.

4.7 California Production Site with Out-of-State Cavern Storage (Mojave Production with Delta Storage)

Sites in California such as Mojave have a substantially higher capacity factor relative to solar power generation and subsequent green hydrogen production potential than Delta, Utah. For this reason, and because salt cavern storage is a proven storage method for hydrogen, a separate system production case was assessed based on hydrogen production in the Mojave area with a pipeline to/from salt cavern storage near Delta, Utah. The [redacted] demand case included pressurized storage at the production site (modeled as [redacted] pipeline) in order to accommodate daily production cycling, reduce the transmission pipeline pressure cycling, and eliminate daily flow oscillations in and out of underground storage.

As mentioned above, the pipeline to Delta salt cavern storage was included to complement in-state storage options and handle the seasonal storage requirements. These features were compiled as System 6. The following diagram shows the component and controls for the hydraulic modelling of this scheme.

FIGURE 10: SYSTEM FLOW DIAGRAM



Additional analysis was performed relative to production at Mojave and using storage in Utah. Mojave was selected as the logical site for this system as it lies geographically between Utah and the Los Angeles Basin and has favorable solar performance. The system was simulated with the controls shown in the figure above. During the peak production times, hydrogen charges the high-pressure (HP) storage, feeds the Los Angeles demand points, and flows toward the storage area in Utah. Intermediate compression in the Las Vegas area would be reversible and was used to manage the pipeline inventory. The daily variation in production rate was accommodated by the variation of HP storage at Mojave and in pipeline pressure, with cavern storage being used primarily for variation in production rate between summer and winter. Cavern storage was also used to supply demand when production was interrupted or reduced for several days by weather/solar interference.

4.8 California Production with Alternate Out-of-State Cavern Storage (Blythe Production with Phoenix Storage)

As part of the second phase of this project study, a potential salt cavern storage site near Phoenix, Arizona was included as a possible option for seasonal storage. Additional analysis was performed relative to production at Blythe and using this potential storage in Arizona. Blythe was selected as the logical conceptual site for this system as it lies geographically between Arizona and the Los Angeles Basin and has good solar performance. The system was simulated with the controls similar to the Mojave/Delta system shown in the figure above. However, Blythe is situated directly along the pipeline route between Phoenix and Los Angeles and could be used to provide intermediate compression when delivering volume originating from Phoenix storage. This allowed the production/compression site at Blythe to provide a relatively constant pressure in the transmission line to the Los Angeles Basin. This case included pressurized storage at the production site (modeled as [redacted]) in order to accommodate daily production cycling, reduce the transmission pipeline pressure cycling, and eliminate daily flow oscillations in and out of underground storage. The pipeline requirement from Blythe toward Los Angeles was calculated as [redacted] for the [redacted] rate cases, respectively.

During the peak production times, hydrogen charges the on-site high-pressure hydrogen storage, feeds the Los Angeles demand points, and flows toward Phoenix area storage. The daily variation in production rate is accommodated by the variation of high pressure gas storage at Blythe and in pipeline pressure, with cavern storage being used primarily for variation in production rate between summer and winter. Cavern storage was also used to supply demand when production was interrupted or reduced by weather/solar interference, which can occur for a number of days

In this development of a hydrogen system to serve southern California, production sites in California such as Blythe are preferable to out-of-state hydrogen production sites. For purposes of this study, seasonal storage at Phoenix is assumed to have similar salt cavern characteristics as Delta. The Phoenix storage site option would provide significant pipeline system savings over the Delta, Utah storage option due to its closer geographical proximity.

5.0 Water Resources

Potential water sources were researched relative to each of the production sites. The following section provides a summary of water demand and viability with more detailed information available in the Phase 1 pre-feasibility water resources reports and included as appendices in this report.

5.1 Demand Scenario

The water resources assessment was based on preliminary demand cases production rates and corresponding water requirements. The assessment and data in the Water Resources Reports have been adjusted in this report to correlate to the final demand rates in this study.

The electrolyzers use demineralized water for the production of hydrogen. The actual amount of water required to produce the needed demineralized water will depend on the quality of water available and the treatment process required. [redacted]

[redacted]

Table 9: Demineralized, Potable, and Recycled Water Demand for Production Scenarios			
Production Scenario	**Daily Demand (acre-feet/day)[1]**	**Daily Demand (million gallons/day [MGD])**	**Annual Demand Acre-feet per year (AFY)**
	Demineralized Water		
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
	Potable Water		
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

Table 9: Demineralized, Potable, and Recycled Water Demand for Production Scenarios			
Production Scenario	**Daily Demand (acre-feet/day)[1]**	**Daily Demand (million gallons/day [MGD])**	**Annual Demand Acre-feet per year (AFY)**
[redacted]	[redacted]	[redacted]	[redacted]
Recycled Water			
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

Notes:

1. [redacted]

5.2 Current Availability

Water availability by production site varies, [redacted]. The high-level water resource study indicated that water resources are over allocated in California. The following table summarizes current, existing major water supply by site.

Table 10: High-Level Existing Water Viability by Site					
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	

Table 10: High-Level Existing Water Viability by Site

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Several types of water sources were explored including groundwater, water projects, recycled water, and desalination. Groundwater basins exist at all sites (Blythe groundwater is part of the Colorado River), [redacted] Water projects import water, such as California Aqueduct (Northern California), Los Angeles Aqueduct (Owen's Valley) and Colorado River Aqueduct (Colorado River). These are considered more reliable but can be seasonal and have generally all been oversubscribed. Recycled water is considered a potentially reliable long term source, and [redacted]. Desalination could also be a potential means of replacing water from another source, including brackish water.

Utah currently does not use its full allocation of Colorado River water (approximately 22% is unused), and has not developed its allocation of Colorado River water, but is in process of expanding its share as projected water demand increases in the state. The water volume required to produce the hydrogen for the conceptual Delta [redacted] Demand case, System 5, as modeled, would be equivalent to approximately [redacted] of total water usage in Utah in 2015.

5.3 Recycled Water

[redacted].

Table 11: Preliminary Assessment of Recycled Water Viability by Site

Production Scenario	[redacted]	[redacted]
Five Points	[redacted]	[redacted]
Mojave	[redacted]	[redacted]
Blythe	[redacted]	[redacted]
Delta	[redacted]	[redacted]

For the Mojave area, [redacted]. For comparison, the existing Lancaster and Palmdale water recycling plants currently have a combined permitted water treatment capacity of 33,500 AFY, but in 2015 only 500 AFY of recycled water was produced and provided to recycled water customers. This indicates that, should sufficient quantities of inflow be provided to the Lancaster and Palmdale WRPs, up to 33,000 AFY of additional recycled water could be produced. In order to procure sufficient inflow, arrangements could potentially be made with local municipalities that do not already use their wastewater for such purposes, to collect and convey their wastewater to the existing Lancaster and Palmdale WRPs for the production of up to 33,000 AFY of additional recycled water. The potential use of recycled water will require further study.

Generally recycled water is only developed when there is an existing, or projected demand for recycled water; as such, available capacity to develop recycled water may be substantially greater than the amount of recycled water actually being developed or projected for development.

The amount of recycled water able to be produced is a direct function of the amount of wastewater entering the treatment system. For purposes of this study, recycled water is assumed to be reliable since it consists of treated waste water generated by an area's population. As long as the population for the service area remains stable or grows, the volume of recycled water available is not expected to vary significantly for average, single-dry, or multi-dry year water conditions. [redacted].

[redacted].

5.4 Existing Water Allocation

Generally, existing surface water and groundwater resources in California are over-allocated, meaning there is greater demand than what is available. [redacted]. However, the amount of SWP water that is actually delivered in the hypothetical production area is highly variable and subject to fluctuations within the state-wide system; for example, in 2021, SWP contractors will only receive 5% of their allocated supply. The following table summarizes major water import projects to the Southern California area.

Table 12: Overview of Major Water Supply Projects
(Source: Mojave Water Resources Report by D. Edwards/Rincon Consultants)

Water Supply Project	Infrastructure Nearest to Mojave	Management	Source Water	Key Summary Data
State Water Project	California Aqueduct	State – DWR	Sacramento-San Joaquin Delta (surface runoff)	131,678 AFY = 2021 SWP allocations to be conveyed in the California Aqueduct to Southern California SWP contractors

Table 12: Overview of Major Water Supply Projects (Source: Mojave Water Resources Report by D. Edwards/Rincon Consultants)				
Water Supply Project	**Infrastructure Nearest to Mojave**	**Management**	**Source Water**	**Key Summary Data**
Central Valley Project	San Luis Unit (San Luis Dam, Reservoir, and Canal)	Federal – USBR	Sacramento-San Joaquin Delta (surface runoff)	75,972 AFY = 2021 CVP allocations for Municipal & Industrial in Southern California
Owens Basin and Mono Lake Projects	Los Angeles Aqueduct	Local – LADWP	Eastern Sierra Nevada Mtns. (snowpack / surface runoff)	190,400 AFY = total 2025 diversions to LADWP via Los Angeles Aqueducts for municipal demands
Colorado River Project	Colorado River Aqueduct	Federal – USBR; State – Multiple; Local – Metropolitan	Colorado River Lower Basin (surface runoff & conjunctive use management)	550,000 AFY = total authorized diversions from Colorado River Lower Basin to Metropolitan via Colorado Aqueduct for municipal demands

Notes:
AFY = acre-feet per year; CVP = Central Valley Project; DWR = Department of Water Resources; LADWP = Los Angeles Department of Water Resources; Metropolitan = Metropolitan Water District of Southern California; SWP = State Water Project; USBR = U.S. Bureau of Reclamation

[redacted].

In contrast, Utah has not developed its full allotment of Colorado River water though it is expanding its system in anticipation of future water demands.

5.5 Expansion of Existing Water Supply

[redacted]

[redacted] For comparison, the existing Lancaster water recycling plant currently has a permitted treatment capacity of 18 million gallons per day (MGD) (20,163 AFY), [redacted]

[redacted]. [redacted]

[redacted].

5.6 Desalination and Other Sources

[redacted]

[redacted]). The Poseidon Carlsbad desalination plant and the proposed Huntington Beach desalination plant each are sized to produce 50 MGD, which is more than the [redacted] MGD of potable water needed for the [redacted] Demand case. Based on news articles only, the Carlsbad plant apparently provides water at $2250 per acre-foot, or $.0069 per gallon of water. Assuming that 2 gallons of desalinated water would have to be produced/exchanged for every 2 gallons of raw potable water taken from an aqueduct, this translates to a water cost of about [redacted] per kg of hydrogen produced. (Note that amount of raw water to process water may be higher than [redacted], depending on the water quality.) Water from the California Aqueduct and the Los Angeles Aqueduct flow relatively close to the Mojave area, and the Colorado River Aqueduct brings additional water to the southern California coastal region, passing through potential green hydrogen production areas.

[redacted], this and other approaches to increasing the water supply should be considered in future feasibility studies.

Water produced from hydrogen fuel cells could also be collected and used for hydrogen production but is not considered in this study.

6.0 Conceptual Pipeline Infrastructure

6.1 Permitting

A high-level, preliminary permit assessment was completed for each conceptual pipeline system and should be referenced for details specific to environmental permitting for each conceptual pipeline system. The assessments include a high-level review of each conceptual route, expected major permits, potential lead agencies and permitting issues and schedule. These individual assessments have been provided as attachments and a summary is provided below.

Pipeline routes are high-level and are subject to further refinement, including re-routing to avoid sensitive areas.

6.2 High-Level Permitting Considerations

For components in California, the project would require completion of environmental review, such as an Environmental Impact Report (EIR), under the California Environmental Quality Act (CEQA). Similarly, approvals by any federal agency would require environmental review, such as an Environmental Assessment (EA) or Environmental Impact Statement (EIS), under the National Environmental Policy Act (NEPA).

A pipeline system will necessarily require a variety of state, local, and potentially federal permits typical of any other large-scale natural gas pipeline, with which the Company is familiar, and are therefore not repeated herein.

Certain special considerations for each of the geographic areas are discussed below.

6.2.1 Five Points

[redacted]

6.2.2 Mojave

[redacted]

6.2.3 Blythe

[redacted].

[redacted]

[redacted].

6.2.4 Delta

[redacted] Components in California would require CEQA review. Further, like California, Nevada would require the project obtain a Certificate of Public Convenience and Necessity (CPCN).

[redacted]

[redacted]

[redacted].

6.2.5 Blythe to Phoenix

[redacted].

6.3 Additional Permitting Considerations and Schedule

Permitting considerations include potential environmental constraints that would complicate the permitting process. Those constraints could increase lead times and permitting requirements associated with the alignments. See Table 22 for representative permitting durations.

Individual reports listed in section 1.4 appendices prepared for each of the pipeline systems summarizes the major permits that may be required and the involved agencies. A separate table is provided summarizing some of the potential permit considerations and options for each route. As potential routes are assessed in future studies, particular areas should be reviewed to determine if re-route of the pipeline is preferable. In addition, the reports include estimated times for obtaining permit approval. Most major permits are expected to take a minimum of one to three years to obtain, without litigation. If permits are challenged these timelines can be extended.

At the Federal level, NEPA lead and/or cooperating agencies could include the Department of Transportation (DOT)/PHMSA, the Federal Energy Regulatory Commission (FERC), or the Bureau of Land Management (BLM) for the Delta and Blythe options.

6.4 Conceptual Pipeline Routes

Conceptual pipeline routes were developed to allow the pipeline systems to be estimated. This allowed the estimates to account for construction type, mileage and other factors at a conceptual level. For purposes of the study, all class 2, 3, and 4 pipe was specified as a class 3 pipe specification and all class 1 was specified as class 1. This adds some conservatism on the material specification of the pipeline. Tables 13A, 13B, and 13C summarize information for the conceptual pipeline systems.

TABLE 13A: TOTAL POINT-TO-POINT MILEAGE FOR ALL CASES AND TOTAL MILEAGE AND CURRENT CLASS LOCATION OF CONCEPTUAL PIPELINES FOR [redacted] DEMAND CASE

[redacted]

TABLE 13B: TOTAL MILEAGE AND CURRENT CLASS LOCATION OF CONCEPTUAL PIPELINES FOR [redacted] DEMAND CASE

[redacted]

TABLE 13C: TOTAL MILEAGE AND CURRENT CLASS LOCATION OF CONCEPTUAL PIPELINES FOR [redacted] DEMAND CASE

[redacted]

6.4.1 Conceptual Route Considerations

Pipelines routed from the production centers to the main demand centers are all [redacted] pipes and may require [redacted] to feed the system. The routes selected are considered conceptual and high level at this stage of study and did not take into account all of the issues associated with routing [redacted] pipelines. No substructure research was completed, and the routes largely follow existing established pipeline corridors.

This high-level conceptual pipeline routing did take into account constructability and SoCalGas standard practices for locating pipelines. [redacted] Thus, the overall mileages are considered representative of actual SoCalGas requirements for pipelines. An allowance for Caltrans (auger bore installations) and major water crossings (Horizontal Directional Drills) has also been included, but is considered preliminary and subject to change.

For this study, new conceptual pipeline routes reflect areas that have been highly developed over time. Other factors that influence pipeline routes are assumptions based on user demands and maximum usage of a Federal Energy Corridor. Users considered are power plants, transportation, refineries, industrial, and commercial. The pipelines may route through and in between cross-country areas, rural and high urban, and production plant boundaries within the wider Central California down to Southern California. Pipeline routes will generally avoid areas that are highly challenging areas for environmental reasons such as national parks, wildlife habitats, and wetlands. When possible, pipelines will route in public land or city right-of-way (ROW).

To capture pipeline routing and destination points, the conceptual pipelines were assumed to route to major demand centers in Los Angeles County. Centers include the following:

- LA Basin Demand Centers Listed in RFI
    - LADWP Power Plants
        - Valley
        - Scattergood
        - Harbor
        - Haynes
    - Ports of Los Angeles and Long Beach
    - LA Industry and Refineries

6.4.2 Co-location within Existing SoCalGas ROW

This assumes the width of the existing easement could accommodate an additional pipeline(s) [redacted] in diameter. Regardless of co-location, additional workspace out of the existing right-of-way for construction would be necessary.

6.4.3 Pipe Corridors

Federal government agencies have established Federal Energy Corridors that would typically reduce the time to plan, permit and construct energy infrastructure projects. The pipeline routes in this study have utilized designated federal utility corridors where they exist. The following designated corridors are used in this study:

Table 14: Designed Federal Energy Corridors

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

6.4.4 Constructability

6.4.4.1 Existing Pipelines

Steel pipeline service conversions were outside of the scope of this study.

6.4.4.2 Type of Construction

For purposes of developing costs, conceptual pipeline routes were categorized and mileage summarized in the cost estimate spreadsheets. The spreadsheets then associated a cost for the pipeline based on the type of construction to estimate the cost of the conceptual pipelines. The construction categories are summarized below:

- Type 1A - Cross Country: Pipeline installation within rural setting assumes no paving, minimum 36" cover, native backfill, minimum 70 ft. wide workspace, limited existing substructures along alignment, no traffic control, minimal environmental restrictions, and unrestricted work hours.
- Type 1B - Cross Country with Environmental Restrictions: The same parameters as Type 1A with the addition of environmental restrictions in place.
- Type 1C - Cross Country with Hilly Terrain/Rocky Soils: The same parameters as Type 1A with the exception that hilly terrain and/or rocky soil conditions are assumed to be present.
- Type 2 - Rural Roadway: Pipeline installation assumes shoulder installation with minimal asphalt paving, minimum 48" cover, native backfill, minimum 2-lane workspace, low density substructures, limited traffic control, minimal environmental restrictions, and normal working hours.
- Type 3 - Secondary Roadway: Pipeline installation assumes asphalt paving, minimum 48" cover, native backfill, minimum 2-lane workspace, medium density substructures, limited traffic control, minimal environmental restrictions, and normal working hours.

- Type 4 - Primary Roadway: Pipeline installation assumes asphalt/concrete paving, minimum 48" cover, slurry backfill, minimum 2-lane workspace, high density substructures, heavy traffic control, minimal environmental restrictions, and restricted working hours (9 am- 3:30 pm).
- Type 5 - Auger Bore: Auger Bore: Assumes cost of bore/receiving pit excavation; auger bore equipment rental and stringing/welding. Assume typical bore length of 200 ft.
- Type 6 – Horizontal Directional Drill (HDD): Assumes cost for equipment rental, 1,500 ft. typical length, and pipe stringing/welding.
- Type 7 - Night Work on Primary Roadway (30% more than Type 3): Pipeline installation assumes asphalt/concrete paving, minimum 48" cover, slurry backfill, minimum 2-lane workspace, high density substructures, heavy traffic control, minimal environmental restrictions, and restricted working hours (10pm - 5am).

6.4.4.3 Auger Bores

Auger bores are assumed for all pipelines crossing Caltrans and RR lines with a typical length of 200 ft. The total crossings for each system and the [redacted] demand case are as follows:

Table 15: Auger Bores in Estimate

System	Total Crossings
System 1, Five Points	[redacted]
System 2, Mojave	[redacted]
System 4, Blythe	[redacted]
System 5, Delta	[redacted]
System 6, Mojave with Delta Pipeline	[redacted]
System 10, Blythe with Phoenix Pipeline	[redacted]
Distribution	[redacted]

6.4.4.4 Horizontal Direction Drills (HDDs)

HDDs are assumed for major waterbody crossings with a typical length of 2,000 ft. The total crossings for each system and the [redacted] demand case are as follows:

Table 16: HDDs in Estimate	
System	**Total Crossings**
System 1, Five Points	[redacted]
System 2, Mojave	[redacted]
System 4, Blythe	[redacted]
System 5, Delta	[redacted]
System 6, Mojave– with Delta Pipeline	[redacted]
System 10, Blythe with Phoenix Pipeline	[redacted]
Distribution	[redacted]

6.4.4.5 Motor Operated Valve Sites (MOV)

MOV sites are assumed to be installed every 16 miles in cross country and rural areas, and every 8 miles in urban areas.

6.4.5 Public Right-of-Way (ROW)

[redacted]

6.4.6 Established Right-of-Way (ROW)

[redacted].

6.5 Design and Pressure Class

6.5.1 Code Requirements

To meet the future build-out of hydrogen pipeline systems, ASME developed and issued ASME B31.12, Hydrogen Piping and Pipelines, with the first edition published in 2008. This code addresses the unique requirements of transporting hydrogen in both facility piping and pipeline systems. ASME B31.12 is formatted similarly to ASME B31.8, Gas Transmission and Distribution Piping Systems. Both provide detailed methods for specifying material, welding requirements, operations and maintenance.

For purposes of this study, this code was referenced for the specification of line pipe. ASME B31.12 adds a significant de-rating factor for higher grade carbon steel pipe as shown in the figure below from ASME B31.12.

FIGURE 11: X-GRADE PIPE DE-RATING FACTORS FOR HYDROGEN PIPELINES FROM B31.12

Table IX-5A Carbon Steel Pipeline Materials Performance Factor, H_f

Specified Min. Strength, ksi		System Design Pressure, psig						
Tensile	Yield	≤1,000	2,000	2,200	2,400	2,600	2,800	3,000
66 and under	≤52	1.0	1.0	0.954	0.910	0.880	0.840	0.780
Over 66 through 75	≤60	0.874	0.874	0.834	0.796	0.770	0.734	0.682
Over 75 through 82	≤70	0.776	0.776	0.742	0.706	0.684	0.652	0.606
Over 82 through 90	≤80	0.694	0.694	0.662	0.632	0.610	0.584	0.542

GENERAL NOTES:

(a) Tables IX-5A, IX-5B, and IX-5C are for use in designing carbon steel, low, and intermediate alloy piping and pipeline systems that will have a design temperature within the hydrogen embrittlement range of the selected material [recommended lowest service temperature up to 150°C (300°F)]. If the system design temperature is out of this range, use the design allowable stresses from Table IX-1A for piping or the specified minimum yield strength for pipelines from Table IX-1B.

(b) Table IX-5A was developed for pipeline systems and as such the design factors are based on the specified minimum yield strength of the material ranges shown.

(c) Design factors may be calculated by interpolation between pressures shown in the tables.

(d) For materials not covered by Tables IX-5A, IX-5B, and IX-5C, use the allowable stresses in Table IX-1A.

For higher grade pipe, a greater wall thickness is required when compared to a natural gas pipeline of the same grade, pressure, and class location. Increases in grade do not result in the same corresponding decreases in wall thickness as for a natural gas pipeline.

Hydraulic analysis showed that the pipeline system should be specified as an [redacted] Pipe materials used in the estimates are as follows:

Table 17: Pipe Selection

Pipe Wall Thickness Selection Table for [redacted] PSI MAOP, [redacted]5 Pipe

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

6.5.2 Recommendations

The pipeline system should be optimized beginning with a reassessment of system capacities. The pipelines have been optimized based on demand scenarios and operating requirements that require [redacted] and high operating pressures. A reduction in design flowrates and capacities could result in significant decreases in pipeline and pipeline facility scope and costs.

6.6 Pressure Cycling

The compressibility of hydrogen gas under pressure allows for significant mass storage in a pipeline. Due to the variation in hydrogen production rate and rate of use at the demand centers, the pipeline system will be subject to pressure cycling. The technical issues relative to hydrogen embrittlement and pressure cycling of hydrogen pipelines are not addressed in this study, other than considering storage and operating concepts that reduce the amount and extent of pressure cycling. On-site high pressure storage in the form of extensive looped large-diameter pipeline is proposed which will cycle from low pressure to high pressure every day. For this high-level study, it is assumed that this on-site storage can be installed in a uniform and controlled manner in an area dedicated to this installation. This should allow for more options in choice of pipe material and design, such that the storage can be designed and installed to accommodate the daily pressure cycling. This daily cycling of on-site storage will reduce the amount of pressure cycling of the transmission lines, but not eliminate it. For two way flow of hydrogen, such as to/from remote storage sites in the Delta and Phoenix areas, the line pressure will cycle every time the flow direction is reversed. To reduce the frequency of this cycling, hydrogen should generally flow toward storage in the summer and from storage in the winter, with occasional full demand rate from storage for supply during days of low solar production.

7.0 Pipeline Compression

7.1 Production Center Pipeline Compressors

Hydraulic analysis was completed for each demand scenario to develop the conceptual compression facilities. Costs developed are parametric with the exception that Rough Order of Magnitude (ROM) costs for the compressor package were obtained from a compressor vendor to validate existing database costs. Analysis indicated that only the Delta option and the hybrid Mojave with Delta Pipeline option, Systems 5 and 6 respectively, needed intermediate compression at the [redacted] rate case. Intermediate compression was not required for the [redacted] and [redacted] rate cases. The Blythe / Phoenix option utilized the production compressors to act as intermediate compressors for moving hydrogen from Phoenix storage to the LA Basin.

The table below summarizes the inputs used for costing the compression facilities. The optimal configurations of the production sites will determine the actual number of compressors required for each site, with costs for those configurations factored based on this large system.

Table 18: Basis of Estimate Production Compressors

Location	Production center origination		
Compressor type (Production site)	Reciprocating		
Rate Case	[redacted]	[redacted]	[redacted]
Quantity and size	[redacted]	[redacted]	[redacted]
Compressor rating	[redacted]		
System maximum capacity	[redacted]	[redacted]	[redacted]
Assumed Inlet pressure	[redacted]		
Assumed outlet pressure	[redacted]		
ANSI class	900		
Motor type	16KV, synchronous motors (dual windings)		
Electrical Substation	With estimate		
Other components	Back-up diesel generator Water treatment system Aftercoolers, Lube oil		

Table 18: Basis of Estimate Production Compressors	
	Inlet scrubbers Firewater Inbound meter skids (4-16" meters) Blowdown system and flare 2,500 SF office building 5,000 SF warehouse building

7.2 Intermediate Pipeline Compressors – Delta and Phoenix Scenarios

The table below summarizes the inputs used for costing the intermediate compression facilities for delivering hydrogen from storage in Delta or Phoenix to the LA Basin. For cases involving production in California and storage in Delta or Phoenix, these compressors will also operate in the reverse direction, packing the line from California to Delta or Phoenix during daily production cycles and to storage in Delta as needed. The optimum configuration of the California production sites may require additional compressors at this intermediate location, and if so, costs can be factored from this base estimate.

Table 19: Basis of Estimate Delta Intermediate Compressors – [redacted] Scenario	
Component	**Quantity and Size**
Location	Near North Las Vegas
Compressor type (Production site)	Reciprocating
Quantity and size	[redacted]
Compressor rating	[redacted]
System maximum capacity	[redacted]
Assumed Inlet pressure	[redacted]
Assumed outlet pressure	[redacted]
ANSI class	900
Motor type	4KV, Variable frequency drives
Electrical Substation	With estimate, assume power is within 3 miles

Table 19: Basis of Estimate Delta Intermediate Compressors – [redacted] Scenario	
Other components	Back-up diesel generator Water treatment system Aftercoolers, Lube oil Inlet scrubbers Firewater Inbound meter skids (4-16" meters Blowdown system and flare 2,500 SF office building 5,000 SF warehouse building

7.3 Underground Storage Compressors

Salt cavern design and costing was not in the scope of this study. Compression requirements for salt cavern storage depend on maximum and minimum operating pressures of the cavern, and have not been estimated and are also not included in the estimates.

Compression requirements for potential oil/gas reservoir storage facilities are a component of the estimates in Section 8.4.

8.0 Conceptual Hydrogen Storage

8.1 Overall Summary of Storage Options

Hydrogen storage is used:

- To manage the variation in daily hydrogen production rate.
- To account for seasonal variation in production rates and demand rates.
- To provide backup supply in the event of system disruption (100% backup rate if possible) or lower production rates.

[redacted] Options for hydrogen storage may serve some or all of three functions: 1) accommodate the daily variation in production rate, 2) provide supplemental hydrogen to make up for lower winter season production rate (Make-up Rates), and/or 3) provide full backup for average demand rate for days of low/no solar production. The capabilities of each type of storage are summarized as follows:

Table 20: Conceptual Storage Option Preliminary Summary			
Storage Type	**Daily Variation in Production Rate**	**Seasonal Storage at Make-up Rates**	**Backup Supply at Full Rate**
Salt Cavern	Yes	Yes	Yes, but possible limitations on demand rate variation
Oil/Gas Reservoir Conversion	Maybe, [redacted]	Yes	Maybe, [redacted]
Onsite Pressure Storage	Yes	No	No
H2 Liquid or Pressure Storage in Los Angeles Basin	Maybe partial; further evaluation needed	No	Possible short term only; further evaluation needed
Ammonia Liquid Storage near production site	No	Yes	Maybe

The use of salt cavern storage currently appears to be feasible for daily and seasonal storage and general backup supply. Geologic storage in a converted oil/gas reservoir, if proven to be feasible in storing hydrogen, will require high pressure compression to inject the hydrogen and process facilities, including dehydration and hydrogen separation/purification, for gas withdrawal. Well capacities and numbers may limit both injection and withdrawal rates. Onsite pressure storage is still limited to providing only daily storage capacity. Liquid or pressure storage in Los Angeles Basin may be of value to a particular user of hydrogen but further evaluation is needed on a case by case basis.

8.2 Salt Cavern Storage

Salt caverns are currently the best method to store large quantities of hydrogen gas underground. Hydrogen has been stored successfully in a salt cavern by Chevron in Texas since the 1980's. This type of storage requires a very large salt dome, which are more common in the US Gulf Coast area, but not common in the Western US. A salt dome in the Delta, Utah area is being developed for hydrogen storage to support the LADWP Intermountain Power Plant. At present, this is the closest salt dome to Los Angeles that has been characterized as capable of large volume hydrogen storage.

There are other potential salt dome areas located in the southwest. The potential to use salt domes on the west side of Phoenix, Arizona is included as part of System 10. Also, a possible Nevada salt dome was identified by HyDeal LA. Both of these potential sites would be closer to Los Angeles than the Delta salt dome and should be tracked as more information becomes available.

This high-level, preliminary study has assumed that hydrogen storage in salt caverns is a proven technology and operation, and that salt cavern storage in Utah would be available if needed. The cost of this storage is not included in this study, as it requires investigation and/or negotiation by SoCalGas. Salt caverns are privately owned and development information relative to storage capacities, flow rates, cost factors, etc. must be obtained in discussion with the owner. Since storage is necessary to meet all the operational needs for the system, it is recommended that some level of analysis be included. Included in the cost of the storage should be consideration of the minimum amount of hydrogen necessary to pressurize and maintain the minimum working pressure in the cavern. For example, it may be required that 30% of the hydrogen that it takes to fill the cavern to maximum pressure may need to remain in storage as cushion gas, maintaining a certain minimum operating pressure.

A review of information available on cavern capacity indicated that the working volume of a cavern (Metric Tons (MT) of H2 gas at maximum pressure minus MT at minimum pressure) could range from 2000 MT to 10,000 MT per cavern. An article published on salt cavern development referred to the Utah site stated "The formation has the potential to create up to 100 caverns, each one capable of holding 150,000 MWh of energy" (Reference: CNBC online article, *An $11 trillion global hydrogen energy boom is coming. Here's what could trigger it*, published November 1, 2020). Assuming that this refers to the energy in the stored hydrogen and not the power that could be produced from it, and also to the working volume of hydrogen in the caverns, the potential hydrogen storage capacity calculates to approximately 4,460 metric tons per cavern At the [redacted] Demand hydrogen production rate, these reported total capacities would accommodate approximately [redacted] of production [redacted] for the [redacted] Demand case; and [redacted] for the [redacted] Demand case). This is also approximately [redacted] times the storage amount required to match the seasonal difference between winter and summer for the [redacted] demand rate, assuming that demand is flat through the year (which it probably will not be).

As another reference point, the Chevron hydrogen salt cavern storage that has operated many years in Texas is reported to have a working capacity of approximately 2,500 metric tons, which at the average [redacted] production rate would fill in approximately [redacted]. This analysis indicates the need to assess the capacity of caverns in each salt dome and how this storage fits with large scale hydrogen system development. At the 4,460 MT/cavern size assumed for the Utah location, seasonal storage alone (with no provision for surplus storage) for the [redacted] Demand case could require [redacted] caverns for the [redacted] Demand case and [redacted] for the [redacted] Demand case).

Caverns typically have limits regarding the number of pressure cycles per year and the rate of change in pressure. Injection and withdrawal rates are typically limited to avoid damage to the structure from rapid pressure change, so multiple caverns would probably operate together to reduce the rate of change in pressure.

This study has not included assessing the capacity and cost of the salt cavern storage, or the analysis and cost of compression and the multiple cavern connections and controls that would be required at the salt cavern storage area.

8.3. Geologic Screening for Potential Oil/Gas Reservoir Storage

The potential storage of hydrogen in existing oil/gas reservoirs is being widely studied and may or may not become viable for incorporation into this project. Storage in existing gas and oil fields in Southern California has not been well studied. Despite the uncertainty of using this type of storage, long term seasonal storage is likely anticipated to be required, and reservoir storage would offer large capacity storage in Southern California. An initial assessment of oil and gas fields in the SoCalGas service territory was performed with the goal of identifying potential viable storage fields for further study.

Storage site candidates were identified from [redacted] onshore oil and gas fields listed in the California Oil and Gas Fields, Volume 1 (Central California, 1998) and Volume II (Southern California, 1992) publications from CalGEM. [redacted]. This left [redacted] potential sites. [redacted] The remaining [redacted] potential storage candidates were then subject to the three filter categories which can be classified as follows:

- Location
- Geological Criteria
- Commerciality

Some manual adjustments were made where unique factors not captured in prior screening, or the filters called for the inclusion or rejection of a site. [redacted] Applying the filter categories, [redacted] potential sites were identified for hydrogen storage.

The process is summarized in the following figure with filters (in grey) set for hydrogen storage criteria.

FIGURE 12: SUMMARY OF SCREENING PROCESS

[redacted]

8.3.1 Pre-Screening

[redacted]

- [redacted]

[redacted]

FIGURE 13: ACTIVE SEISMICITY IN SOUTHERN AND CENTRAL CALIFORNIA AND SHORT-LISTED CANDIDATES

[redacted]

Notes:

1. InterAct Study, Assessment of Underground Storage in oil and/or Gas Reservoirs, 8/27/21.

2. Red lines represent recent fault traces identified by the California Geological Survey.

8.3.2 Location Filter

[redacted]

- [redacted]
- [redacted]

8.3.3 Geologic Filter

A[redacted]

- [redacted]
- [redacted]
- [redacted]. [redacted]

8.3.4 Commerciality Filter

[redacted]

- [redacted]
- [redacted]
- [redacted]

8.4 Geologic Storage in Oil/Gas Reservoir

[redacted]. A separate report listed in the appendices in section 1.4 regarding assessment of existing reservoirs for hydrogen storage, the "Assessment of Underground Storage in Oil and/or Gas Reservoirs Report", has additionally been prepared.

Multiple studies are being performed globally regarding the issues and challenges of geologic storage of hydrogen which includes existing oil/gas reservoirs, so the "Assessment of Underground Storage in Oil and/or Gas Reservoirs Report" is not intended to assess the feasibility of such storage. Due to the desirability of a storage facility closer to Los Angeles than the salt caverns in Utah, existing southern California oil and gas fields were assessed relative to their potential to store hydrogen, should such storage be proven to be workable. Consistent with that overview, the report has also included a high level assessment of the cost to develop a hydrogen storage reservoir and associated facilities, should it prove to be feasible.

[redacted]

[redacted]

The following table summarizes the key design assumptions used for estimating the topside facilities at a conceptual field in the Castaic Junction area. In the studied case, peak production rate in the summer is approximately 138% of average annual production rate. This Peak Injection Rate to storage is therefore based on injecting the incremental 38% excess production during this time. This rate is sufficient for seasonal storage but not to fully manage daily production variation. The lowest daily production rate of the year in the studied case is approximately 34% of the average annual production rate. The Peak Withdrawal Rate from storage is therefore based on withdrawing the additional 66% of annual production rate required for full backup of the average rate. These rates are for estimating topside facilities. Until better information is developed, injection and withdrawal rates of wells are based on the reported volumetric capacity of similar natural gas storage field wells (15-20 MMSCFD injection; 40-50 MMSCFD withdrawal).

Multiple parallel trains for pressure swing adsorption (PSA) are included for separating the hydrogen from methane and other hydrocarbons and gases that may be produced with the hydrogen. Assessment of topside facilities is limited and intended primarily for establishing order-of-magnitude cost estimate.

Table 21: Basis of Estimate for Conceptual Underground Storage Site

Component	Quantity and Size		
	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]		
[redacted]	[redacted]		
[redacted]	[redacted]		
[redacted]	[redacted]		
[redacted]	[redacted]		

Table 21: Basis of Estimate for Conceptual Underground Storage Site			
[redacted]	[redacted]		
[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]		

8.5 Onsite Pressure Storage

As mentioned in Sections 3 and 4, further consideration has been given to pressurized storage at the production site which includes a long pipeline looping back multiple times in a large area. [redacted] Such storage at production sites would allow the site to deliver hydrogen to the pipeline at a steadier rate throughout the day, would reduce the number and size of pipelines from what would otherwise be required, and would reduce the pressure cycling of the transmission pipelines. This concept may also be advantageous for the staged development of the system. Transmission line pressure cycling would have a greater effect on required storage volume for lower production rate early-stage development. Onsite storage would be added at each production site as total production volume increases and the pipeline operates closer to full capacity most of the time. This type of storage will help with the daily production rate variation but will not affect seasonal or backup storage.

8.6. Above-ground Storage in/near Los Angeles Basin

The modeled above-ground storage options are likely too small to have a significant impact on the overall operation of this system. Above-ground storage may have some value to individual customers, but this is not currently economic to enhance the operation of this hydrogen pipeline system. This report does not consider potential future advancements in aboveground bulk storage of hydrogen.

The largest liquid hydrogen storage sphere in the world is 5,000 cubic meters (m^3), which has the capacity of approximately to 2 hours of average production at a [redacted]. Other liquid storage spheres have been designed, but not constructed at up to 8 times this volume (40,000 m^3). The cost for the storage sphere alone is approximately [redacted] The energy required to liquefy hydrogen for storage is approximately 1/3 of the energy value of the hydrogen stored, and the cost of liquefaction facilities typically exceeds the cost of the spheres. Liquid hydrogen storage is practical for applications where the hydrogen will be used or stored on-board as a liquid.

Budget costs (rough order of magnitude) were provided by CB&I Storage Solutions/McDermott, which recently constructed the 5,000 m^3 liquid hydrogen storage sphere at the NASA space center in Florida. The following current day cost estimates took into consideration installation in California (for seismic conditions) and the use of union labor.

8.6.1 Liquid Hydrogen Storage Spheres

- 5,000 m^3 Storage Sphere (working capacity of approx. 320 MT liquid H2): [redacted] foundation, storage along with typical accessories, plus [redacted] deluge system and fireproofing of the columns.
- 2,250 m^3 Storage Sphere (working capacity of approx. 160 MT liquid H2): [redacted] for foundation, storage along with typical accessories, plus [redacted] deluge system and fireproofing of the columns.
- Boil-off percentage per day <0.1% (recovered/re-liquefied by liquefaction system).

8.6.2 Hydrogen Liquefaction Systems

- Filling 5,000 m^3 sphere in 4 days with a liquefaction rate of 200 gpm (54 kg/min): [redacted]
- Filling 5,000 m^3 sphere in 12 days with liquefaction rate of 70 gpm (19 kg/min): [redacted]

Overall, liquefaction has high capital and energy cost and is a relatively slow process.

8.6.3 Hydrogen Vaporization System (approximately [redacted] psig gas pressure)

- Vaporization rate of 1,000 gpm (268 kg/min): [redacted]
- Vaporization rate of 300 gpm (80 kg/min): [redacted]

8.6.4 Pressurized Gaseous Hydrogen Storage Sphere

- 5,000 m³ GH2 Storage Sphere at a 30 bar ([redacted] psig) design pressure: [redacted]
- Budget costs were provided for a 5000 m³ pressurized gas storage sphere at 30 bar pressure. [redacted]. This working volume is based on the difference in pressure between the maximum and minimum storage pressures. A 5000 m³ sphere operating between 6 bar and 30 bar pressures would have a working volume of 10 metric tons of hydrogen, about 3% of the working capacity of the same size liquid sphere. For comparison, a 42" pipeline 3.75 miles in length would provide the same physical volume and could store more due to higher allowable pressure. At the [redacted] estimated cost of the sphere, the equivalent 42" pipeline cost per volume would be $[redacted] per mile. [redacted]

8.7. Ammonia/Chemical Storage

Chemical storage of hydrogen in the form of anhydrous ammonia was not included in this prefeasibility assessment due to the additional energy required by the hydrogen/ammonia/hydrogen conversion process and potential challenges in permitting storage near demand centers. [redacted]. Ammonia production is not expected to have a substantial impact on daily storage requirements, but could be effective for seasonal storage and backup supply. A single tank could potentially hold 50,000 MT of ammonia, or about 8800 MT of hydrogen. Approximately [redacted] of these tanks would be required for the minimum seasonal storage for the [redacted] Demand case, [redacted] tanks for the [redacted] Demand case, and [redacted] tanks for the [redacted] Demand case.

9.0 Schedule

9.1 Precedence

Due to the scale of the potential project, an overall project schedule would require more thorough development after selection of a build option and demand scenario. Production of hydrogen at this scale would require significant permitting, vendor, and construction resources. [redacted]

9.2 Permitting

A multi-year permitting process under CEQA and/or NEPA is expected for a project of this scale. The social, economic and environmental impact of any conceptual project would draw a large number of stakeholders including municipal and government agencies, community groups, businesses groups and other special interests.

The following table from the "Mojave Conceptual Pipeline Permit Assessment" report provides representative permit times for major permitting agencies for major industrial type projects. The durations are based on the general experience of the environmental consultant team.

Table 22: Representative durations for pipeline project permits

Agency or Entity	Authorization	Anticipated Lead Time (months)[1]
	Federal	
NEPA	EIS	18-24
BLM	ROW Grant	12-18
National Park Service (NPS)	ROW Permit	variable
NPS	Consultation	variable
U.S. Forest Service (USFS)	New Special Use SUP	18-24
U.S. Fish & Wildlife Service (USFWS)	Section 7 Consultation Biological Opinion	6-9
USFWS	Section 10 Habitat Conservation Plan	18-24
Federal Department of Defense	Military Base Approval	6-18

Table 22: Representative durations for pipeline project permits

Agency or Entity	Authorization	Anticipated Lead Time (months)[1]
U.S. Army Corps of Engineers (USACE)	404 Certification	6-12
	State	
CEQA	EIR	12-24
California Department of Parks and Recreation (State Parks)	SUP	12-24
California Department of Transportation (Caltrans)	ROW Encroachment / Transportation Permit	6-12
California Energy Commission (CEC)	TBD	n/a
California Department of Fish and Wildlife (CDFW)	CESA ITP	12-36
CDFW	§1600 Programmatic Short-term LSAA	12-18
RWQCB	Individual 401 Certification and Waste Discharge Re-equipment (WDR)	12-24
	Regional: County/City/Community Plan/Special District	
Special Districts		6-12
Local Air District	Clean Air Act	1-3
Railroad (RR) Crossings	ROW, Encroachment potentially a SUP	4-6
	County	
Kern/San Bernardino County	Director Determination	1-3
Los Angeles	CUP Protected Tree Permit Significant Ecological Areas (SEAs)	6-24

Table 22: Representative durations for pipeline project permits

Agency or Entity	Authorization	Anticipated Lead Time (months)[1]
	Cities	
City Governments	CUP Anticipated	6-12
All cities	Protected Tree Permit	1-3

9.3 Materials

Purchase of materials, particularly those related to the production of hydrogen at the scale considered in this report has not yet been done and more than likely would require build-out over several years. To determine an accurate schedule for production, a detailed review of build out scenarios is recommended for discussion with material vendors (particularly for electrolyzers, PV panels, line pipe and compressors).

Materials for pipeline, facilities and storage would also be considered long lead but are primarily supplied by well-established industries. Therefore, material deliveries are more predictable but will vary based on overall market demand at the time of purchase.

9.4 Construction

Construction of the hydrogen facilities would likely involve a multi-year process and would be difficult to predict without further analysis of build-out scenarios. The construction of pipelines and pipeline facilities is well understood, so construction of these facility types would be more predictable, although these pipeline systems would be considered multi-year build-outs due to their scale.

Construction for this size project would involve multiple construction spreads, out-of-state and international contractors and significant logistical planning in preparation for construction. To determine an accurate schedule for construction, a detailed review of build out scenarios is recommended for discussion with construction firms (particularly for production, pipeline and compression facilities).

10.0 Estimates

10.1 Accuracy

The estimates completed for this study are considered rough order of magnitude and were developed with limited engineering and design work. Estimate factors used were developed in discussion with Campos Engineering and referred to AACE International Recommended Practice No. 97R-18, Cost Estimate Classification, as the basis for developing contingency and accuracy range factors.

With the level of engineering and design completed at this stage of study, the estimate was classified as a class 5 estimate defined as 1% to 15% engineering, this pre-feasibility study would fall on the lower end of this range. The accuracy ranges vary from (-15% to -50%) on the low end and from (+20% to 100%) on the high end, depending on the technical complexity of the project. Given the scale and engineering complexity of this highly technical type of project, the largest ranges of accuracy were selected.

Estimate factors are summarized below:

Table 23: Project Estimate Factors

Estimate Classification	Level 5
Engineering Level	1% to 15%
Contingency Factor	50%
Estimate Accuracy Low Range	-50%
Estimate Accuracy High Range	+100%

10.2 Methodology

The study estimate uses gross unit costs/ratios and parametric estimating methods. Campos Engineering provided factored rates for use in estimating pipeline costs and facilities. These rates are based on current SoCalGas data from existing similar, but much smaller scale projects. Therefore, cost estimate factors do not reflect economies of scale and cost optimization that would potentially be experienced by such a large project.

For the hydrogen production and energy generation parametric cost estimates were also utilized, primarily consisting of data available from the National Renewable Energies Laboratory (NREL) Annual Technology Baseline (ATB) costs. The cost basis data from NREL is developed using a number of financial models with multiple assumptions and inputs to produce the CAPEX and OPEX costs utilized in this report. The parametric pricing therefore includes consideration for the following inputs:

- [redacted]

Since the majority of the cost of production is from the renewable energy production, the NREL model inputs are also provided for reference (see hydrogen production report). Similarly, the NREL estimates are based on existing similar, but much smaller scale projects and therefore the cost estimate does not reflect economies of scale and cost optimization.

10.3 Uncertainty and Cost Optimization

With the factored estimate methodology, the cost estimate uncertainty though high would typically be offset by the high contingency and range factors discussed in the section above. Subsequent studies would presumably select a preferred option and complete some preliminary engineering to reduce the uncertainty associated with a class 5 estimate. Also, cost optimization could be accomplished in discussion with outside experts, such as pipeline construction contractors, to increase the accuracy, reduce uncertainty and reduce contingency and accuracy range factors.

10.4 Major Cost Items Not Included in Estimates

Due to the high-level nature of the study some cost items were not included in the estimate. These factors would have significantly increased the costs and conservatism and was deemed unnecessary given the high-level nature of the study, unknown execution strategy and very long time of the project. These factors included the following:

- Demolition is excluded. All project sites are assumed to be green field sites with no existing facilities, soil or ground water contamination.
- Escalation is excluded given the uncertain timeline of the conceptual buildout.
- Storage costs do not include purchase of a potential storage field for Five Points, Mojave, or Blythe options.

- Storage costs for Delta and Phoenix options do not include development of salt caverns. To the project understanding, it is assumed that salt cavern storage is being developed by third party companies.
- SoCalGas Loaders such AFUDC, depreciation, corporate taxes, etc. are excluded.

10.5 Cost Estimates for [redacted] and [redacted] Cases

At this level of study, cost estimates for the [redacted] and [redacted] Demand cases were factored from the [redacted] demand base cases. The following table summarizes the factors for each major estimate component:

Table 24: [redacted] and [redacted] Case Estimate Factors

Estimate Component	Factor
Production	Factored from [redacted] demand case based on total production ratio.
Pipeline	Re-estimated based on new mileage and sizes.
Pipeline Compression	Factored from [redacted] case based on horsepower ratio.
ROW – Production and Pipelines	Factored from [redacted] demand case based on total acreage ratio.
Underground Seasonal Storage	Factored from [redacted] demand case based on quantity of on-site compression, dehydration units, PSA's and gas wells.
Underground Daily Storage	Factored from [redacted] demand case based on mileage of buried pipe.

10.6 Total Project Cost

TABLE 25A: [redacted] PRODUCTION CASE PROJECT CAPEX COST SUMMARY

[redacted]

TABLE 25B: [redacted] PRODUCTION CASE PROJECT OPEX COST SUMMARY

[redacted]

TABLE 25C: [redacted] PRODUCTION CASE PROJECT CAPEX COST SUMMARY

[redacted]

TABLE 25D: [redacted] PRODUCTION CASE PROJECT OPEX COST SUMMARY

[redacted]

- [redacted]
- [redacted]
- [redacted]
- [redacted]

TABLE 25E: [redacted] PRODUCTION CASE PROJECT CAPEX COST SUMMARY

[redacted]

TABLE 25F: [redacted] PRODUCTION CASE PROJECT OPEX COST SUMMARY

[redacted]

- [redacted]
- [redacted]
- [redacted]
- [redacted]

10.7 Cost Optimization

Pipeline and facility cost estimates use data provided by Campos Engineering. The data provided preliminary and based on SoCalGas rates and costs for pipelines and facilities and are, therefore, a relatively accurate reflection of SoCalGas costs for project execution. [redacted]

Potential cost savings options are discussed in the table below and is based on the project team's experience with other pipeline companies and projects.

[redacted]

[redacted]		
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

Appendices

A.1 Modeled Preliminary Production Cost Summaries

[redacted]

1. [redacted].

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

A.3 Conceptual Pipeline System Compression Cost Summaries

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

A.4 Conceptual System Right-of-Way Cost Summaries

[redacted]

[redacted]

[redacted]

A.5 Conceptual Seasonal and Daily Storage Cost Summaries

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]