December 31, 2021

Aliso Canyon I.17-02-002 Phase 3 Report

ASSESSMENT OF PORTFOLIO SOLUTIONS FOR ELIMINATING THE USE OF THE ALISO CANYON NATURAL GAS STORAGE FACILITY BY 2027 OR 2035

Gas Supply Consulting, Inc.

FTI CONSULTING

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I. Executive Summary

Overview

The California Public Utilities Commission ("CPUC") initiated the Aliso Canyon Well Failure Order Instituting Investigation (I.17-02-002, "OII") to "determine the feasibility of minimizing or eliminating the use of Aliso Canyon Natural Gas Storage Facility while maintaining energy and electric reliability"[1] as required by Senate Bill 380. This OII has been addressed in three phases.

In Phase 1 of the investigation, CPUC's Energy Division staff ("ED staff") gathered input from stakeholders to create a Scenarios Framework that outlined the scenarios that would be modeled and the assumptions that would be used to determine whether Aliso Canyon usage could be minimized or eliminated given current rules and infrastructure.[2]

In Phase 2 of the investigation, ED staff managed and performed the modeling outlined in the Scenarios Framework. The first Phase 2 report on the econometric modeling was released on November 2, 2020.[3] The second report — which included the production cost modeling for minimum local generation scenarios, the hydraulic modeling for 1 in 10 and 1 in 35 design year scenarios,[4] and the feasibility assessment — was published in redacted form on February 3, 2021.[5] An unredacted version was published on March 28, 2021.[6]

This Phase 3 study addresses the request specified in a November 18, 2019, letter to the CPUC from Governor Gavin Newsom asking that the CPUC engage an expert advisor to "identify viable alternatives to the facility and scenarios that can inform a shorter path to closure."[7] The CPUC selected FTI Consulting, Inc. ("FTI") and Gas Supply Consulting, Inc. ("GSC") to conduct the Phase 3 study to answer the following two questions:

1. What infrastructure investments (portfolio solutions) are required to retire Aliso Canyon?
2. What are the costs and benefits of the portfolio solutions identified?

Per CPUC's direction, the portfolio solutions must be operationally and commercially reasonable, adequately address the entire natural gas shortfall created by the retirement of Aliso Canyon, and

[1] I.17-02-002, Ordering Paragraph 1: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M173/K122/173122830.PDF
[2] https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M254/K771/254771612.PDF
[3] https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=349931623
[4] SoCalGas must meet a reliability standard of 1 in 35 for Core customers, 1 in 10 for Noncore customers, and 1 in 35 for Core local transmission customers per D.02-11-073, Ordering Paragraph 10: https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/21286.PDF
[5] 363969892.PDF (ca.gov)
[6] 369286397.PDF (ca.gov)
[7] Letter from Governor Newsom to CPUC https://efiling.energy.ca.gov/GetDocument.aspx?tn=230806&DocumentContentId=62422.

conform to relevant CPUC Orders and Statutes, including those related to Demand-Side Management and Decarbonization goals.

Approach

For Phase 3, a 1 in 10 Winter Peak Day for 2027 and 2035 was modeled to address potential gas and power issues created by the retirement of Aliso Canyon for a reference scenario (“Base Case”) and for each of the portfolio solutions. The 1 in 10 Winter Peak Day represents colder than normal weather conditions estimated to have a ten percent likelihood of occurrence in any single calendar year.

The modeling approach followed two distinct workstreams:

1. **Workstream 1 – Operational Analysis:** simulate the operation of the electric and gas systems on an hourly basis under 1 in 10 Winter Peak Day conditions to determine what, if any, gas demand is unserved in the Base Case scenario. Based on those results, specify portfolio solutions that would allow for the retirement of Aliso Canyon without impacting system reliability.
2. **Workstream 2 – Benefits Analysis:** conduct economic analyses to determine the portfolio solutions that provide the highest benefit and/or least cost from a ratepayer’s perspective.

In Workstream 1, two models were applied: (1) an electric system production cost model, and (2) a natural gas hydraulic model.

In Workstream 2, cost-benefit analysis (“CBA”) was conducted for each portfolio solution. The CBA considered each solution’s capital and operational costs, electric and natural gas market impacts, and the social cost of carbon emissions.

Base Case Gas and Electric Shortfalls

In the Base Case modeling, the hydraulic model was used to estimate the maximum gas demand that could be served by the SoCalGas system without Aliso Canyon in 2027 and 2035. To do so, the model was first run under 1 in 10 Winter Peak Day conditions for a period of four consecutive days. The result was a model failure due to an inability of the system to meet demand requirements.

To reach a workable solution, the hydraulic model was then run under the same conditions but by incrementally reducing SoCalGas-connected, gas-fired electric generators from the least efficient to the most efficient. This was done until total demand was low enough to be supported by the SoCalGas system such that total system receipts, system deliveries, and linepack usage were balanced each day over the four-day period for 2027 and 2035.

The Base Case analysis found that SoCalGas-connected electric generators, at the minimum, would need to reduce their gas consumption by 395 million cubic feet per day (“MMCFD”) in 2027 and 323 MMCFD in 2035 for supply and demand to be balanced on the SoCalGas system under 1 in 10 Winter Peak Day conditions. These values define the “Gas Shortfall” for each planning year. The drop in the

Gas Shortfall from 2027 to 2035 results from the forecasted decline in total gas demand on the SoCalGas System.[8]

A comparable exercise was conducted to determine the equivalent "Electric Shortfall" for the Base Case, expressed in MW of capacity. The Electric Shortfall was evaluated on an hourly basis and was defined as the difference between (1) total generation no longer produced from curtailed plants that otherwise would have been produced if Aliso Canyon were not retired and (2) the remaining import capacity into the California ISO ("CAISO"). The Electric Shortfall was estimated to be 3,176 MW in 2027 and 2,875 MW in 2035 and occurs at 10 PM for both planning years. At 10 PM in both planning years, the remaining import capacity in CAISO was forecasted to be zero.

Portfolio Solutions and Key Findings

The following five portfolio solutions were identified for replacing Aliso Canyon ahead of 2027 or 2035, except for Portfolio 4, which was considered only for 2035 due to long expected lead times for identifying, evaluating, approving, constructing, and commissioning transmission lines:

- **Portfolio 1:** Gas Transmission Expansion – consists of natural gas supply increases either through additional pipeline capacity and/or access to additional storage capacity
- **Portfolio 2:** Gas Demand Reduction – consists of a combination of Building Electrification, energy efficiency, and gas demand response
- **Portfolio 3:** Electric Generator Additions – consists of a set of zero-carbon generation capacity above Base Case levels that relies principally on the resource mix from the 11.5 gigawatts ("GW") net qualifying capacity ("NQC") CPUC order[9]
- **Portfolio 4:** Electric Transmission Additions – consists of transmission lines that increase the CAISO interface and/or increase transmission into Los Angeles Department of Water and Power ("LADWP")
- **Portfolio 5:** Hybrid – consists of certain elements from Portfolios 1-4 that cost-effectively address the shortfalls in 2027 and 2035

[8] California Gas and Electric Utilities, *2020 California Gas Report*, 96. https://www.socalgas.com/sites/default/files/2020-10/2020_California_Gas_Report_Joint_Utility_Biennial_Comprehensive_Filing.pdf
[9] https://docs.cpuc.ca.gov/SearchRes.aspx?docformat=ALL&docid=389603637

Table 1 and Table 2 below present the key portfolio modeling results for 2027 and 2035, respectively.

Table 1: 2027 Cost Benefit Summary Results (Millions of 2019$)

Portfolio	Costs	Benefits	Benefit-Cost Ratio	Net Benefits	Reduction in CO_2 Emissions (million metric tons)
Portfolio 1a	$100.4	$0.0	N/A	($100.4)	0.000
Portfolio 1b	$147.3	$0.0	N/A	($147.3)	0.000
Portfolio 2	$197.9	$247.3	1.25	$49.4	1.857
Portfolio 3	$653.0	$712.6	1.09	$59.7	1.243
Portfolio 5a	$196.3	$283.1	1.44	$86.8	2.097
Portfolio 5b	$375.5	$435.8	1.16	$60.3	1.673
Portfolio 5c	$513.9	$548.3	1.07	$34.4	1.481

Table 2: 2035 Cost Benefit Summary Results (Millions of 2019$)

Portfolio	Costs	Benefits	Benefit-Cost Ratio	Net Benefits	Reduction in CO_2 Emissions (million metric tons)
Portfolio 1a	$66.8	$0.0	N/A	($66.8)	0.000
Portfolio 1b	$118.3	$0.0	N/A	($118.3)	0.000
Portfolio 2	$644.3	$193.6	0.30	($450.7)	0.986
Portfolio 3	$596.7	$895.1	1.50	$298.4	1.072
Portfolio 4a	$125.5	$195.3	1.56	$69.8	0.061
Portfolio 4b	$89.6	$176.3	1.97	$86.7	(0.035)
Portfolio 5d	$239.1	$65.3	0.27	($173.8)	0.427
Portfolio 5e	$122.0	$83.5	0.68	($38.5)	0.268
Portfolio 5f	$99.5	$126.3	1.27	$26.8	0.170

Key findings include the following:

- Portfolio 1a and Portfolio 1b would provide the two lowest cost solutions in 2027, and Portfolio 1a would provide the lowest cost solution in 2035. Neither of the Portfolio 1 solutions offer any benefits as these solutions only provide a replacement for the gas supply that otherwise would be sourced from Aliso Canyon.
- Portfolio 2 has the second highest benefit-cost ratio and reduction in CO_2 emissions in 2027, but has the highest costs and the second lowest benefit-cost ratio in 2035.
- Portfolio 3 would provide the highest benefits in both 2027 and 2035, but also the highest costs. Portfolio 3 has a benefit-cost ratio greater than 1.0 in both years.
- Portfolio 4a and Portfolio 4b represent the solutions with the highest benefit-cost ratios but the lowest CO_2 emissions reductions in 2035.
- Portfolio 5a represents the solution with the highest benefit-cost ratio and CO_2 emissions reductions for 2027. In 2035, the Portfolio 5 solutions have lower benefit-cost ratios than the Portfolio 3 and Portfolio 4 solutions but offer lower costs than Portfolio 3 and higher CO_2 emissions reductions than Portfolio 4.
- The CO_2 emissions reductions associated with each Portfolio versus the Base Case are generally lower in 2035 than in 2027. This is primarily due to the projected growth in the contribution of renewable generation resources to the California generation mix and forecasted declines in both electric and gas demand. The 2035 Base Case CO_2 emissions level of 58 million metric tons is approximately 6 percent lower than the 2027 Base Case CO_2 emissions level of 62 million metric tons.
- Excluding Portfolios 1a and 1b, the net financial benefits for gas rate payers would be positive for each Portfolio solution evaluated due to the lack of gas market investment costs and a forecasted reduction in gas prices, while the net financial benefits for electric rate payers would be negative for each Portfolio solution evaluated with the sole exception of Portfolio 4b in 2035. As such, in most Portfolios evaluated, almost all investment costs would be passed onto electric rate payers, while almost no investment costs would be passed on to gas rate payers.

II. Introduction

A. Background on Aliso Canyon

On October 23, 2015, Southern California Gas Company ("SoCalGas") discovered a leak at its Aliso Canyon underground storage facility while performing routine observations. The leak was found near the top of Oat Mountain, outside of Los Angeles. Before it was neutralized, an estimated 4.6 billion cubic feet ("Bcf") of natural gas escaped over the course of 112 days through an axial rupture in the well casing.

In response to the leak, the California legislature passed Senate Bill ("SB") 380 requiring state regulators to complete a safety review of the storage facility, determine the feasibility of minimizing or eliminating the use of Aliso Canyon, and evaluate the level of working gas required to ensure safety, reliability, and reasonable rates for customers. Consequently, the CPUC issued an order in Docket Card I.17-02-002 instituting an investigation ("CPUC Investigation") "...to determine the feasibility of minimizing or eliminating the use of the Aliso Canyon natural gas storage facility located in the County of Los Angeles while maintaining energy and electric reliability for the Los Angeles region and just and reasonable rates in California."[10]

With a working gas capacity of 86 Bcf prior to this leak, Aliso Canyon was one of the largest gas storage facilities in the United States. It was a critical source of gas for the Southern California market, accounting for nearly two thirds of SoCalGas's total storage capacity, with additional entitlements held by other local market participants. Today, the CPUC has restricted Aliso Canyon's working gas capacity to 41 Bcf.[11]

B. CPUC Investigation Study Phases

The CPUC Investigation into the need for the continued use of the Aliso Canyon storage facility has been undertaken in three phases as described below.

Phase 1

In Phase 1 of the investigation, ED staff gathered input from stakeholders to create a Scenarios Framework[12] that outlined the scenarios that would be modeled and the assumptions that would be used to determine whether reliance on Aliso Canyon for gas and electric system reliability could be minimized or eliminated given current rules and infrastructure. That Scenarios Framework laid out a plan for hydraulic, production cost, and economic modeling of the SoCalGas system to estimate how

[10] Investigation 17-02-002. Order Instituting Investigation pursuant to Senate Bill 380 to determine the feasibility of minimizing or eliminating the use of the Aliso Canyon natural gas storage facility located in the County of Los Angeles while still maintaining energy and electric reliability for the region. Filed 12/20/2019.

[11] CPUC, November 4, 2021, *CPUC Helps Ensure Energy Reliability for Southern California*, [Press Release]. https://www.cpuc.ca.gov/news-and-updates/all-news/cpuc-helps-ensure-energy-reliability-for-southern-california

[12] Scenarios Framework I.17-02-002, Prepared by CPUC Energy Division, September 13, 2018.

reducing or eliminating use of Aliso Canyon would impact gas and electric reliability, electric costs and reliability, and natural gas commodity costs.

The Scenarios Framework was adopted in an Assigned Commissioner and Administrative Law Judge's Ruling at the end of Phase 1.[13]

Phase 2

The purpose of Phase 2 of the proceeding was to perform the modeling outlined in the Scenarios Framework and issue reports based on that analysis. ED staff conducted most of the Phase 2 modeling. However, due to resource constraints, some hydraulic modeling scenarios were run by SoCalGas with oversight from ED staff and Los Alamos National Laboratories. Modeling results were presented and discussed at four public workshops, in June 2019, November 2019, July 2020, and October 2020.[14]

The first report, which detailed ED staff results from the econometric modeling, was released on November 2, 2020. The second report includes the remaining results, which are the production cost modeling for minimum local generation scenarios, the hydraulic modeling for 1 in 10 and 1 in 35 design year scenarios, and the feasibility assessment.

Phase 3

Phase 3 addresses the request specified in a November 18, 2019, letter to the CPUC from Governor Gavin Newsom asking that it engage an expert advisor to "identify viable alternatives to the facility and scenarios that can inform a shorter path to closure."[15]

In December 2019, the CPUC issued an order initiating Phase 3 under Docket Card I.17-02-002 and began the process by which a consultant would be selected to develop scenarios, conduct implementation assessments, and produce a report on how Aliso Canyon could be fully retired prior to the start of two different planning years identified by the Energy Division, 2027 and 2045, and to evaluate the impacts on reliability and costs in the region.

The CPUC selected FTI and GSC to conduct the Phase 3 study, which was designed to answer the following two questions:

1. What infrastructure investment options are required to retire Aliso Canyon?
    - What does an acceptable 1 in 10 Winter Peak Day Base Case forecast indicate as the natural gas demand shortfall in 2027 and 2035 if Aliso Canyon were retired?
    - What solutions could alleviate this potentially unserved demand, including energy efficiency, electrification, demand reduction and demand management programs,

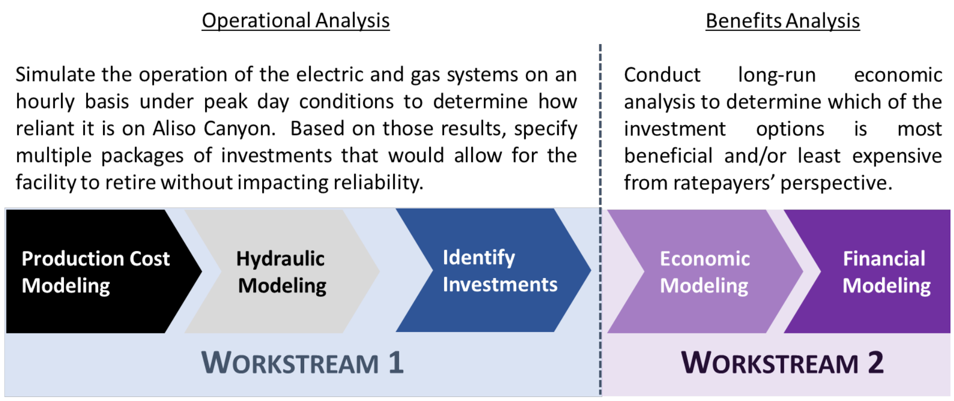
[13] https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M254/K771/254771612.PDF
[14] https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M369/K286/369286397.PDF
[15] Letter from Governor Newsom to CPUC https://efiling.energy.ca.gov/GetDocument.aspx?tn=230806&DocumentContentId=62422.

replacement of gas transmission pipelines or the construction of new gas transmission pipelines, new electric generation resources that are carbon neutral or act to integrate renewable energy, and new transmission resources?

2. What are the costs and benefits of the available options?
   - What are the investment costs required?
   - What level of ongoing operational and maintenance expenditures are required?
   - What are the greenhouse gas impacts?
   - What are the reliability impacts?
   - What other risks and benefits should be considered?

FTI's and GSC's analysis for Phase 3 followed two distinct workstreams, as shown in Figure 1 below.

Figure 1: Phase 3 Workstreams



Workstream 1 Analyses Timeframes

CPUC's scoping memo indicated directed that the Phase 3 study would examine two different planning horizons: 2027 and 2045. This direction was interpreted as requiring the study to examine the impact of Aliso Canyon's retirement *prior to* 2027 and 2045, respectively, but not necessarily on those dates.

The ultimate dates for the Phase 3 analysis were selected by considering two factors:

- The dates must be either actionable or provide useful insight.
- The dates must be sufficiently different in terms of market evolution to yield a meaningful difference between the selected dates.

Based on the above considerations, 2027 and 2035 were selected as the planning years for which to analyze the impacts of Aliso Canyon's retirement.[16]

[16] "2027" and "2035" are used throughout the report to refer to the planning years evaluated, under the assumption that Aliso Canyon is fully retired prior to the beginning of each planning year.

III. Base Case Assessment

Separate Base Cases were developed for the 2027 and 2035 planning years to determine the amount of unserved demand if Aliso Canyon were to be retired prior to the beginning of the planning year. As explained in the Executive Summary, the unserved demand can be stated as a Gas Shortfall, expressed as a daily volumetric amount (MMCFD), or as the equivalent Electric Shortfall, expressed in terms of total available capacity (MW).

Daily gas demand is primarily driven by heating demand and is generally forecasted to peak when temperatures are coldest. The 1 in 10 Winter Peak Day represents colder than normal weather conditions estimated to have a 10 percent likelihood of occurrence in a single calendar year, based on SoCalGas's statistical analysis of historical minimum average daily temperatures pertaining to the SoCalGas system.[17]

For example, SoCalGas analysis indicates that there is a 10 percent chance that on the coldest day of a given calendar year, the daily temperature will be at least as cold as 42.2 degrees Fahrenheit.[18] Historical data on which the SoCalGas analysis was based indicates that this condition has been met 10 times in the last 70 years, with the most recent occurrences in January of 2007 when the daily system average temperature was 41.6 degrees and December of 1990 when the daily system average temperature was 39.1 degrees.[19]

For planning purposes, extreme weather conditions, such as those associated with a 1 in 10 Winter Peak Day, are applied in forecasting models to assess system performance and market impacts during periods of significantly higher than normal demand.

A. Base Case Development

A Base Case assessment was first completed for the November 2020 Phase 3 workshop. This first assessment was based on electricity resources in the 2019-2020 Reference System Plan developed through the Integrated Resource Plan process ("2019-20 IRP/RSP").[20]

The final version of the Base Case was completed in August 2021. It reflected two important changes that occurred between November 2020 and June 2021:

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[17] SoCalGas, *2020 California Gas Report Redacted Workpapers*, 327. https://www.socalgas.com/sites/default/files/2020-10/SoCalGas_2020_CGR_Redacted_Workpapers.pdf
[18] Ibid, 318.
[19] Ibid, 319-320.
[20] Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements. Decision 20-03-028 March 26, 2020

1. The submittal of an update to the 2019-2020 IRP for CAISO's 2021-22 Transmission Planning Process, which reflected a new California Energy Commission ("CEC") load forecast (the 2019 IEPR Mid Case,[21] updated from the 2018 IEPR Mid Case[22]); and,
2. A June 2021 CPUC order requiring the procurement of 11,500 MW of additional NQC resources by 2026.

B. Summary of Supporting Models

Analysis of the Base Case, as well as subsequent analyses of Portfolios 1 to 5, relied on three distinct models: PLEXOS for production cost modeling, NextGen for hydraulic modeling, and GPCM ("Gas Pipeline Competition Model") for natural gas market modeling. These models are summarized below.

PLEXOS

PLEXOS is a widely used electric market modeling platform licensed from Energy Exemplar. It has a powerful engine that mimics electric market operations to determine the least-cost, system-wide solution. PLEXOS can be configured and run as a nodal model with a representation of electrical buses, as well as the topology of the transmission network connecting them. PLEXOS can also be run as a zonal model in which the market footprint is divided into balancing authorities ("BAs")[23] with transmission links between the BAs. Within PLEXOS, the system can be simulated on an hourly basis or using a load duration curve that divides a month or a season into blocks of similar hours.

For this study, PLEXOS was run in a zonal, hourly configuration for the entire Western Electric Coordination Council ("WECC") area, which includes California and CAISO.[24] The WECC footprint was divided into BAs with transmission links between the BAs. This configuration is very similar to that used by the CPUC's SERVM ("Strategic Energy & Risk Valuation Model") model used for IRP planning. The similarity in geography allows for many of the SERVM assumptions to be precisely aligned with the PLEXOS model used for this research. For example, because BAs match exactly, the SERVM balancing authority to balancing authority transmission line limits and wheeling charges can be made to match exactly.

PLEXOS includes all the generation units in the WECC footprint. In the zonal configuration, generation resources are placed in applicable BAs based on their physical location. To mimic market operations,

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[21] *2019 Integrated Energy Policy Report*, Docket No. 19-IEPR-01.

[22] *2018 Integrated Energy Policy Report*, Docket No. 18-IEPR-01.

[23] Balancing authorities are entities responsible for maintaining a balance between electric load, interchange, and generation within a given jurisdiction.

[24] WECC promotes bulk power system reliability and security in the Western Interconnection, whose footprint extends from Canada to Mexico and includes the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of the 14 Western states. WECC is the Regional Entity responsible for compliance monitoring and enforcement and oversees reliability planning and assessments. In addition, WECC provides an environment for the development of Reliability Standards and the coordination of the operating and planning activities of its members as set forth in the WECC Bylaws. See https://www.wecc.org/Pages/AboutWECC.aspx.

generation resources across the market footprint are dispatched to achieve least cost subject to constraints such as inter-zonal transmission limits and unit operating constraints. Outputs from a PLEXOS run include unit dispatch and electric market prices by BA. For the purposes of identifying the potential Gas Shortfall in this study, the dispatch of gas-fired units connected to the SoCalGas system and the associated gas burn by hour, day, and year are critical PLEXOS outputs.

Detailed PLEXOS modeling results are provided as a supplemental material in file "Detailed Power Market Modeling Inputs and Results.xlsx." The contents of this file are described in "Appendix I: Detailed Power Market Modeling Inputs and Results."

NextGen Hydraulic Model

The Project Team utilized Gregg Engineering's NextGen pipeline hydraulic modeling software as a platform to develop steady state and transient flow simulation models of the SoCalGas system. Gregg Engineering has been providing hydraulic pipeline simulation modeling software since 1986. Gregg's NextGen software is the industry standard in the US and around the world as a platform for modeling hydraulics of natural gas gathering, transmission, and distribution pipeline networks and is widely used by pipeline companies, Local Distribution Company ("LDC") system planners, and market regulators.

Gregg's NextGen Steady State Pipeline Hydraulic Simulation Software enables a user to replicate the physical parameters and flowing conditions of a pipeline system. In developing simulation models, the software user develops the underlying model by inputting relevant data for a pipeline system such as:

- Gas properties (gas composition, gas temperature, gas heating value, gas pressure, etc.)
- Pipe, regulator, compressor, and gas storage properties (pipe diameter, pipeline length, pipeline roughness, compressor horsepower ("HP") etc.)
- Operating conditions (ambient temperature, ground temperature, elevation, etc.)
- User defined pipeline equations (i.e., Weymouth, Panhandle, Colebrook, AGA, etc.)
- Receipt and delivery quantities

The Project Team utilized NextGen software to evaluate the operations of the pipeline systems under changing conditions. As deliveries to end users, particularly electric generators, are rarely made on a uniform static basis, the use of the transient analysis[25] functions within the NextGen software are critical to the evaluation of the capability of the pipeline infrastructure to meet varying demand requirements during a day.

The transient hydraulic model is utilized to evaluate flowing natural gas quantities and associated pressures on the SoCalGas system throughout the day. Natural gas receipt quantities are held constant during the day whereas demand fluctuates during a day with customer requirements. During periods

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[25] Within the transient analysis function, a minimum time step of one (1) minute was selected to insure a complete and robust calculation.

of low demand during the day, if natural gas receipt quantities exceed demand, then the pipeline system will pack up (the amount of gas within the pipelines themselves, known as line pack, will increase and pipeline pressures will increase accordingly). Conversely, during off peak hours, if demand exceeds the amount of gas received into the system, the system will draft down (line pack and on-system pressures will decrease) during peak delivery periods. As such, the NextGen software is used to model these changing conditions during a day, ensuring that all demand is met and pipeline pressures stay within acceptable ranges.

Detailed Hydraulic Modeling results are provided as a supplemental material and are described in "Appendix II: Detailed Hydraulic Modeling Results."

GPCM

GPCM is a model of the North American integrated natural gas market, which was developed and is updated quarterly by RBAC. It is a network model consisting of points where natural gas is produced, bought, sold, stored, and consumed and paths through these various points representing the pipeline grid, which delivers gas from producing areas to consumers. GPCM solves for an equilibrium solution in the natural gas market and generates a forecast of delivered prices, indicated by location through the North American pipeline network, as well as forecasts of gas produced (supply), gas consumed (demand), and flows across pipelines differentiated by segment.

RBAC provides a reference case database that was used as the Base Case for this study and then modified for the various portfolio solutions examined. The proprietary GPCM reference case database is maintained and updated in-house by RBAC and includes assumptions for future weather, economic growth, world oil price, and energy industry developments such as pipeline and storage projects, coal-plant conversions to gas, liquified natural gas ("LNG") bunkering, and renewable natural gas ("RNG") use.[26]

The highly detailed reference database includes:

- 109 supply areas
- 6 supply types (shale, coal-bed methane, conventional, synthetic natural gas, LNG, and RNG)
- 14 shale plays (Barnett, Haynesville, Marcellus, Utica, Eagle Ford, etc.)
- 37 LNG projects (existing, under-development, proposed)
- 250+ pipelines (interstate, intrastate, Gulf of Mexico gathering, LNG headers)
- 442 storage facilities
- 113 demand areas

[26] https://rbac.com/gpcm-base-case-natural-gas-forecast-briefing/

- 450 utilities and industrial customer groups
- 5 demand sectors (residential, commercial, industrial, electric, and transportation)
- 100+ market points mapped to Platts Gas Daily pricing hubs
- LNG demand outlook from RBAC's G2M2 Global Gas & LNG Simulator

The GPCM model computes natural gas supply, demand, prices, basis, pipeline flows, storage activity, LNG activity, and natural gas liquids ("NGL") production.[27]

The estimated changes in city-gate gas prices for each Portfolio, as compared to the proprietary GPCM reference case, are provided as a supplemental material in the file "GPCM Monthly Gas Price Changes Relative to Base Case.xlsx."

C. Base Case Modeling Key Inputs and Results

Table 3 outlines the process steps for how the Gas and Electric Shortfalls for 2027 and 2035 were calculated.

Table 3: Process Steps for Calculating Gas and Electric Shortfalls for 2027 and 2035

Process Step	Process Step Description	Key Output
Production Cost Modeling	Power market simulations were performed in PLEXOS to generate the hourly gas burn on a 1 in 10 winter peak day for each of the 235 current and planned gas-fired generation units in the study footprint, calibrated to the 2020 California Gas Report[28] 1 in 10 Winter Peak Day demand projections	Hourly Gas Demand by Customer Segment
Hydraulic Modeling	Estimated hourly gas burns based on the 1 in 10 Winter Peak Day were input into the Next Gen hydraulic modeling software. Hydraulic modeling simulations were performed to identify the maximum hourly gas demand that could not be served to Electric Generators in the absence of Aliso Canyon ("Gas Shortfall")	Hourly Gas Shortfall
Electric Shortfall Calculation	The Gas Shortfall was used to adjust the initial Production Cost Modeling inputs related to gas supply available for Electric Generation demand. Power market simulations were re-run to determine the electricity generation shortfall ("Electric Shortfall") remaining if electricity production was reduced to fill the Gas Shortfall.	Hourly Electric Shortfall

These above process steps are explained in further detail below.

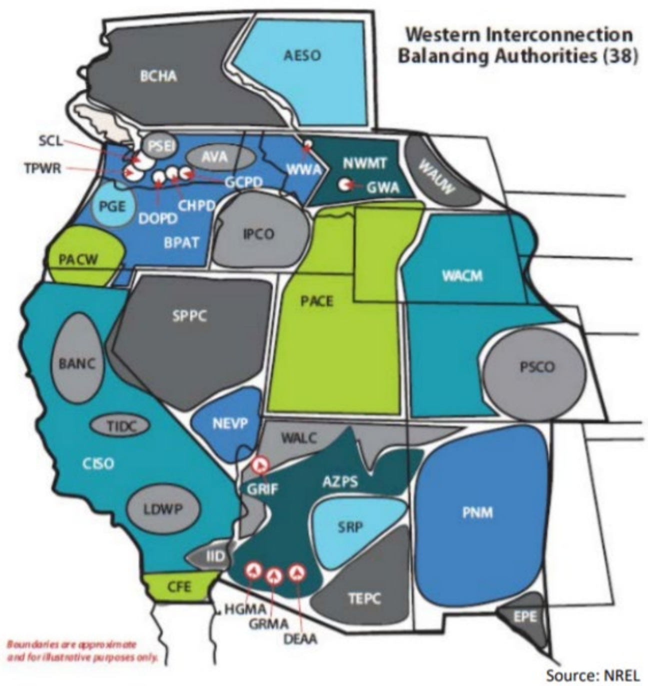
[27] Ibid.
[28] https://www.socalgas.com/sites/default/files/2020-10/2020_California_Gas_Report_Joint_Utility_Biennial_Comprehensive_Filing.pdf

Production Cost Modeling

Modeling Framework

Electric market operations were represented in an hourly WECC-wide zonal model, which represents the WECC system as 34 BAs.[29] CAISO is represented in the WECC Zonal Model with three distinct sub-zones for Southern California Edison ("SCE"), San Diego Gas & Electric ("SDG&E"), and Pacific Gas and Electric ("PG&E"). These are shown as the aggregate region "CISO" in Figure 2 below.

Figure 2: WECC Balancing Authorities[30]



The electric demand forecasts used for production cost modeling for each BA were generated by summing hourly baseline demand forecasts with hourly load-modifying demand forecasts for the period 2018 through 2035, as detailed in the process steps below.

1. Hourly base demand forecasts were constructed using Integrated Energy Policy Report ("IEPR") annual peak load and total energy forecasts and normalized consumption profiles provided in the form used by the SERVM model. Peak load and total energy for 2035 were extrapolated from the IEPR forecasts for 2030 using each balancing authority's five-year compound annual growth rate.

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[29] The North American Electric Reliability Council defines a BA as "The responsible entity that integrates resource plans ahead of time, maintains demand and resource balance within a Balancing Authority area, and supports interconnection frequency in real time." See: https://www.nerc.com/files/glossary_of_terms.pdf.

[30] WECC Staff (2014). Loads and Resources Methods and Assumptions.

   a. The process for scaling the annual peak load and total energy forecasts to the hourly level using the normalized consumption profiles is detailed in section 2.6.3. in "Guidance for Production Cost Modeling and Network Reliability Studies."[31]
2. Hourly demand-side modified forecasts were constructing using IEPR forecasts and normalized consumption profiles provided in the form used by the SERVM model. Demand-side modifier forecasts were extrapolated for 2035 using each modifier's five-year compound annual growth rate.
3. Hourly base load and demand-side modifiers were added together to represent the total hourly load for each balancing authority.
4. The peak winter day was defined as the day with the maximum coincident winter peak load over the set of SERVM balancing authorities.

Once the hourly total load forecasts for each balancing authority were constructed, the PLEXOS model was run for the full hourly chronology in each of 2027 and 2035. Gas demand from the peak winter electric load day was compared to the 1 in 10 Winter Peak Day electric generation sector gas demand from the California Gas Report and the 1 in 10 Winter Peak Day electric generation sector gas demand from the CPUC's Phase 2 analysis.

Next, the production cost model was calibrated to reflect three consecutive days of 1 in 10 Winter Peak Day conditions through an iterative process by adjusting underlying assumptions related to non-gas fired generation facility outages and peak day load. These adjustments were made to generate electric generation sector gas demand results that were comparable to the projected 1 in 10 Winter Peak Day gas burns presented in the 2020 California Gas Report for SoCalGas and SDG&E and from the CPUC's Phase 2 analysis. The results of the calibration process for peak day electric generation sector gas demand are shown below in Figure 3. It is important to note that changes made subsequent to this initial calibration process, such as updating generating units to include information released in the Transmission Planning Portfolio ("TPP") and 11.5 GW NQC procurement order, ultimately lowered the peak day gas demand figures from PLEXOS for both 2027 and 2035 from those shown in Figure 3 to those shown in Table 5.

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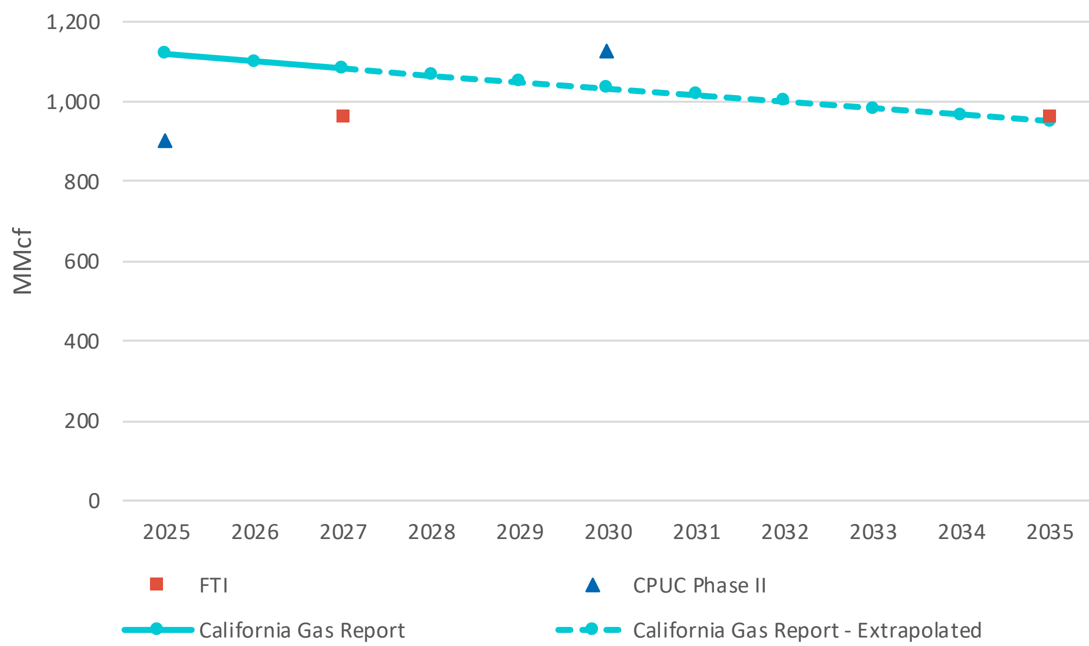
[31] *Unified Resource Adequacy and Integrated Resource Plan Inputs and Assumptions – Guidance for Production Cost Modeling and Network Reliability Studies*. CPUC Energy Division, Energy Resource Modeling Section. March 29, 2019

Figure 3: Initial Calibration of Peak Day Gas Demand from EG



Key Inputs & Assumptions

The Base Case representation of the WECC electric system relies on power market data from industry-accepted, publicly available sources and proprietary data, research, and analysis conducted by the licensor of PLEXOS, Energy Exemplar. Table 4 below provides a discussion of Production Cost Modeling inputs used in the Base Case analysis and indicates the sources used to develop the inputs.

Table 4: Production Cost Modeling Inputs – Base Case

Input	Discussion	Sources
Generation Resources	• The generation units available to meet load on the 1 in 10 Winter Peak Day of 2027 and 2035 (the analysis years) include: • The existing fleet of generation assets as of 2019 • Planned generation resources and those required under IRP procurement orders through 2027 and 2035, respectively • Retirements through 2027 and 2035, respectively	• Existing units based on Unified RA and IRP Modeling Datasets 2019; cross-checked with EIA data • Planned resources and retirements based on CPUC submittal to CAISO to support the 2021-22 Transmission Planning Process ("2021-22 TPP") (achieving 46 million metric tons of carbon dioxide equivalent in 2030, using 2019 IEPR forecasts)[32] and further adjusted to meet the CPUC order for procurement of 11.5 GW of Net Qualifying Capacity by 2026
Transmission Topology	• The model represents 34 BAs in WECC with the CAISO balancing authority being further disaggregated into three sub-zones • The model BAs are linked by transmission links with a defined capacity for each link defined based on an IRP dataset	• SERVM documentation as presented in Unified RA and IRP Modeling Datasets 2019
Electric Demand	• The annual load by BA (in MWh), as well as the peak is based on the CEC's demand forecast, which includes demand modifiers for energy efficiency and electric vehicles • The 1 in 10 winter peak day hourly load is derived as stated in the previous section of the report.	• CEC, 2019 IEPR Mid Case for California; Anchor Data Set from WECC for outside California • Peak and Total Energy Forecasts for SERVM by Region from Unified RA and IRP Modeling Datasets 2019

Modeling Results

The hourly generation for each gas generator connected to the SoCalGas system represents the key output of the PLEXOS Base Case modeling of the 1 in 10 Winter Peak Day for 2027 and 2035 assuming no constraint is placed on gas use.

Generation at Enhanced Oil Recovery ("EOR") facilities and refineries was assumed to be fixed at the levels forecasted in the 2020 California Gas Report. As such, this generation was not included in the PLEXOS modeling and is shown separately from SoCalGas-Connected Electric Generators in Table 5 below. Table 5 summarizes the PLEXOS results for "Total" and "SoCalGas-Connected" electric generator demand on a 1 in 10 Winter Peak Day.

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[32] The addition of new generation resources for planning years beyond the time horizon of the 2021-22 TPP was based on linear extrapolation.

Table 5: PLEXOS Results for Unconstrained Gas Burn on a 1 in 10 Winter Peak Day (MMCFD)

	2027	2035
Core	3,101	2,987
Noncore, Non-Electric	670	653
Total Electric Generator Demand	**745**	**803**
EOR - Electric	52	50
Refinery - Electric	72	71
SoCalGas-Connected Electric Generators	**621**	**682**

Loss of Load Expectation ("LOLE") and Loss of Load Probability ("LOLP") were not calculated as PLEXOS was applied in a deterministic fashion for this study. Nevertheless, it is possible to identify the directionality of how the Base Case and scenarios in this study would impact LOLE and LOLP. While the Base Case introduces a 1 in 10 Winter Peak Day load that was absent from the TPP modeling, the 1 in 10 Winter Peak Day load for electricity in California remains significantly lower than peak load in the summer months, the only months for which SERVM analysis of the TPP showed non-zero expected unserved energy.[33] Furthermore, the CPUC Phase 2 analysis found that no study years showed LOLE in the winter months, reinforcing the notion that electric reliability in California is principally a summer issue.[34] As such, because the Base Case inherits the attributes of the TPP, including summer peak load, and adds additional generating resources to conform with the 11.5 GW NQC procurement order, the Base Case portfolio should be more reliable and have lower LOLP and LOLE than the TPP, which has been shown to solve to acceptable LOLP and LOLE.[35]

Hydraulic Modeling

Modeling Framework

As part of Phase 2 in its proceeding, CPUC developed a representation of the SoCalGas System using the Synergi Gas Model,[36] which, like the NextGen Model used in this analysis, represents the physical and operational details of the gas system.

Because the Phase 2 work had been completed and vetted, the first task was to develop a NextGen model that was calibrated or "tuned" to produce practically the same results as CPUC's Synergi Gas Model for the base year used by CPUC.

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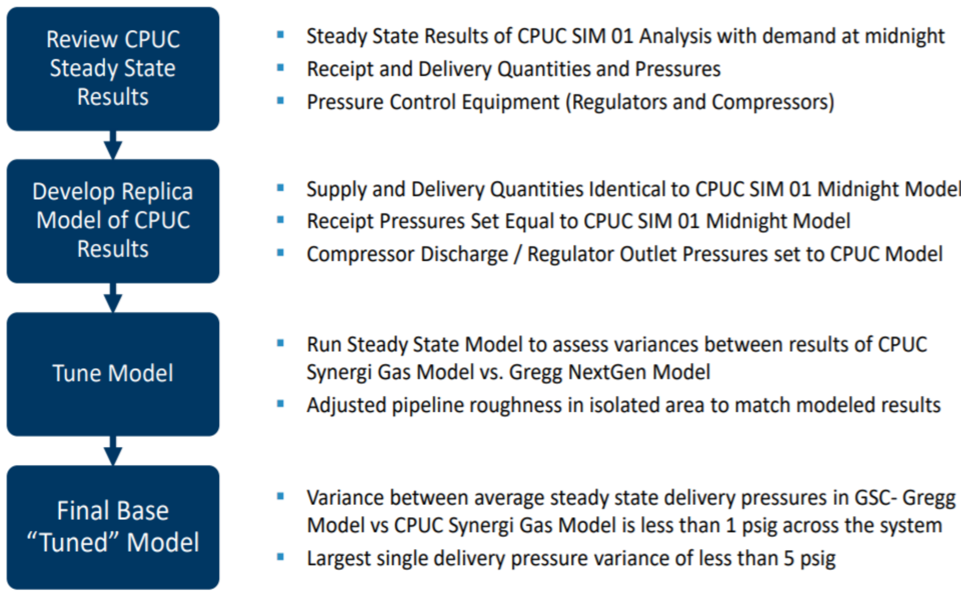
[33] CPUC Staff. *SERVM analysis of IRP 46 MMT Portfolio for use in 2021-22 TPP*. January 14, 2021
[34] CPUC Staff. *Aliso Canyon I.17-02-002 Phase 2: Modeling Report*. January 26, 2021
[35] CPUC Staff. *SERVM analysis of IRP 46 MMT Portfolio for use in 2021-22 TPP*. January 14, 2021
[36] CPUC Staff. *Aliso Canyon I.17-02-002 Phase 2: Modeling Report*. January 26, 2021

Upon tuning the NextGen model, the second task was to conduct gas system operational analyses for 2027 and 2035. Figure 4 shows the hydraulic modeling preparation process.

Figure 4: Hydraulic Modeling Preparation Process



<u>Key Inputs and Assumptions</u>

The four key inputs and assumptions that drove the hydraulic modeling process are described below.

Demand

Demand that must be served on the SoCalGas System consists of the following components:

- Core demand
- Noncore, non-electric demand
- EOR-electric demand
- Refinery-electric demand
- SoCalGas-connected electric generator demand

The demands for the components listed above, except for SoCalGas-connected electric generators, were sourced from the 2020 California Gas Report, as shown in Table 3 above. Demand from SoCalGas-connected electric generators was based on PLEXOS modeling as discussed earlier.

Technical

The major technical inputs for the Hydraulic Model are shown in Table 6.

Table 6: Hydraulic Model Technical Inputs

Input	Base SIM 01 Replica Model	Adjustments/Variances in Final Model
Natural Gas Properties	• Specific Gravity: 0.60 • Gas Flowing Temperature: 65° F • Ambient (Ground) Temperature: 60° F	• Gas Temperature Set at 65° F at receipt points • Temperature Tracking Enabled /Ground Temperature at 60° F
Underlying Flow / Compression Formulas	• Colebrook White Friction Factor • General HP Equation	• No Adjustments
Base Conditions	• Temperature Base: 60° F • Pressure Base: 14.73 PSIG	• No Adjustments

Pipeline Supply

Supply estimates were based on the nominal capacity for each zone, which were adjusted based on the following assumptions:

- Southern Zone and Northern Zone available supplies reflect 85 percent Receipt Point Utilization ("RPU"), while Wheeler Ridge Zone available supplies reflect 100 percent RPU, both are consistent with the supply assumptions in CPUC's Phase 2 analysis[37]
- Southern Zone supplies in excess of 980 MMCFD are required to be sourced from the Otay Mesa receipt point
- Otay Mesa supplies are capped at 50 MMCFD[38]
- California producers in the North Coastal Zone supply 70 MMCFD, consistent with historical flows

Total available pipeline supply into the SoCalGas system from various sources was estimated to be 3,115 MMCFD in 2027 and 2035 after accounting for the RPU assumptions and outages on the Northern Zone.[39] Figure 5 provides a table showing a breakdown of available supply by receipt point

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[37] CPUC Staff. *Aliso Canyon I.17-02-002 Phase 2: Modeling Report*, 28. January 26, 2021

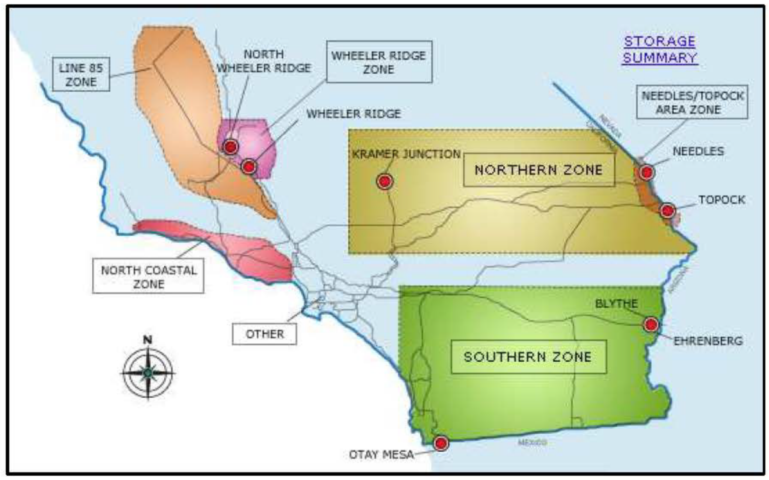
[38] This assumption is consistent with the supply assumption for Otay Mesa utilized by CPUC within its "S05-Winter 2030" model of the SoCalGas system absent Aliso Canyon.

[39] Northern Zone receipts of 1,250 MMCFD consistent with Phase 2 analysis assumption for peak winter 2025 and 2030 analyses. As described on Page 34 of Aliso Canyon I.17-02-002 Phase 2: Modeling Report, "The Northern Zone receipts of 1,250 represent an 85 percent utilization factor of 1,590 MMCFD (which yields 1,351.5MMCFD) plus the additional partial outages of Lines 3000, 235-2, and 4000 (which discounts another 101.5MMCFD leading to 1,250 MMCFD of available supplies in the Northern Zone)."

along with a corresponding system map marking the geographic location of the receipt points in each zone.

Figure 5: Available Supply by Receipt Point in 2027 and 2035 and Corresponding System Map

Pipeline Supply Source	Quantity (MMcf/d)
North Needles	430
South Needles (Topock)	400
Kramer Junction	420
Wheeler Ridge	765
Blythe Ehrenburg	980
Otay Mesa	50
CA Producers	70
Total – Pipeline Supply	**3,115**



Storage

On a 1 in 10 Winter Peak Day, the combined withdrawal capacity for the three SoCalGas storage facilities assumed to remain in service after the proposed retirement of Aliso Canyon – Honor Rancho, La Goleta, and Playa del Rey – was estimated to be 821 MMCFD in 2027 and 1,050 MMCFD in 2035. These storage withdrawal capacities were developed based upon the results of a seasonal[40] mass balance analysis used to determine minimum storage inventory levels (and associated withdrawal capacity at such inventory levels) during the winter season. The seasonal mass balance analysis is discussed in further detail in "Appendix II: Detailed Hydraulic Modeling Results."

As reflected in the seasonal mass balance analysis, seasonal natural gas demand on the SoCalGas system is projected to decline in future years resulting in a lower seasonal demand quantity in 2035 than in 2027. Lower seasonal demand in 2035 results in a lower utilization of natural gas storage in 2035 than 2027, which in turn leads to higher storage inventories during the winter season. As higher storage inventories support greater withdrawal capacity, the seasonal mass balance analysis yields higher available withdrawal capacities on the 1 in 10 Winter Peak Day in 2035 than in 2027.

Figure 6 below provides a system map marking the geographic location of the four storage facilities assessed in the analysis – Aliso Canyon, Honor Rancho, La Goleta, and Playa del Rey.

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[40] The winter withdrawal season spans November through March and the summer injection season spans April through October.

Figure 6: Storage Facilities Assessed in the Hydraulic Modeling

Withdrawal capacities at the minimum inventory levels calculated in the mass balance analysis for each storage facility were estimated based on storage curve data provided by SoCalGas in response to a CPUC staff data request dated July 23, 2019.[41] These curves were applied to the storage inventories calculated within the mass balance analysis to determine available withdrawal capacities at each storage field on the 1 in 10 Winter Peak Day. Storage inventory available on a 1 in 10 Winter Peak Day occurring at the end of the winter season is assumed to be 54 percent in 2027 and 82 percent in 2035.[42]

Key operating assumptions utilized to evaluate available storage withdrawals from each storage field included the following:

- Honor Rancho storage is utilized as a balancing resource and is assumed to be able to withdraw at any level between 0 MMCFD and the maximum available withdrawal level, based upon available inventory, during peak day operation.
- Playa del Ray storage is assumed to operate such that inventories are maintained to maximize peak day withdrawal capacity, resulting in the majority of seasonal storage withdrawals within the seasonal storage analysis being sourced from Honor Rancho and La Goleta.

[41] SoCalGas Response Dated July 23, 2019, to CPUC-Energy Division Data Request Dated July 22, 2019, pursuant to PUC Section 583, GO 66-D and D.17-09-023

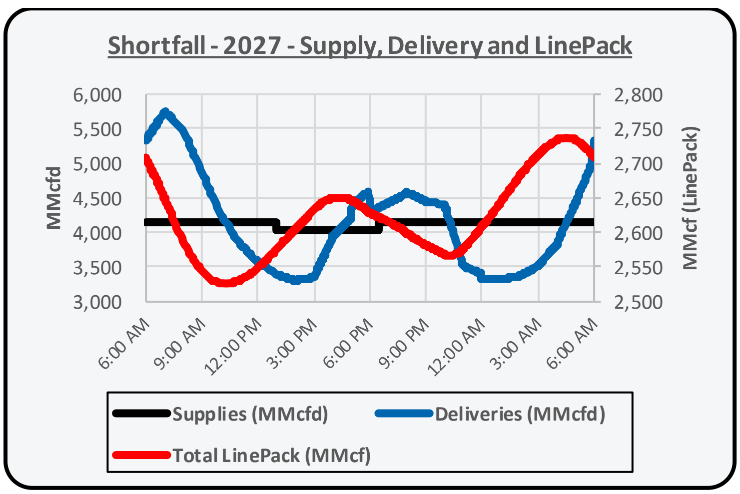
[42] Mass balance analysis results are included in Supplemental Materials.

Modeling Results

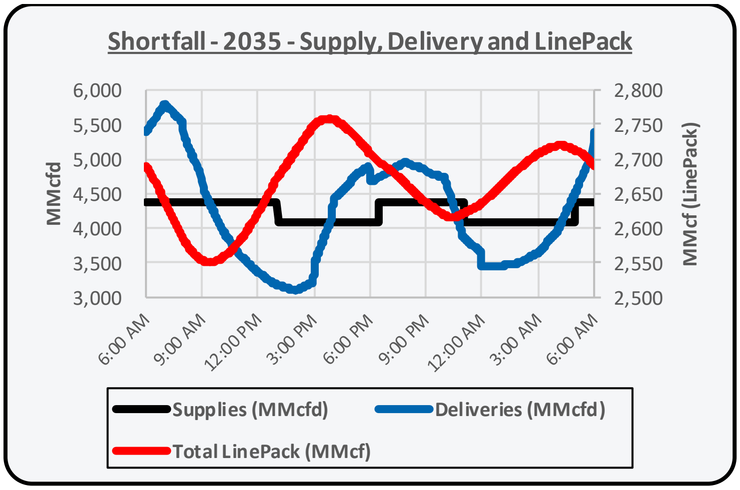
The NextGen hydraulic model was used to estimate the maximum gas demand that could be served by the SoCalGas system without Aliso Canyon. To do so, the model was first run incorporating the full amount of 1 in 10 Winter Peak Day demand, consistent with CPUC Phase 2 modeling approach. The result was a model failure due to an inability of the system to meet demand requirements.

To reach a workable solution, EG demand was reduced from the least efficient (highest heat rate) to the most efficient EG facilities until total demand was low enough that it could be supported by the SoCalGas system. The EG facilities thus no longer operating on a 1 in 10 Winter Peak Day are listed in the file "Summary Demand Table 2027 and 2035.xlsx".[43] The following charts show the total system receipts, system deliveries, and linepack usage during the day for the final, balanced shortfall models for 2027 and 2035. As illustrated in these charts, linepack (red line) recovers back to its starting value during the 24-hour period, which is an indication of a successful model run. Demand (blue line) and supply (black line) also return to their starting values, ready for the next day.

Figure 7: Total System Receipts, System Deliveries, and Linepack for 2027 and 2035 on a 1 in 10 Winter Peak Day



[43] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/natural-gas/aliso-canyon/summary-demand-table-2027-and-2035-redacted.xlsx



Next, to ensure that the system delivery capacity was replicable and the system would respond during a multi-day event, the hydraulic model was run under 1 in 10 Winter Peak Day conditions for a period of four consecutive days. The model runs were successful, reflecting the modeled system's ability to support four peak days.

The difference in gas-fired Electric Generation demand between the initial model run, which incorporated total 1 in 10 Winter Peak Day demand with no constraints and resulted in a model failure, and the optimal successful model, which incorporated demand reduction from EGs until demand was servable without Aliso Canyon, represents the Gas Shortfall. This is shown in Table 7 below as the "Demand Reduction (EG)" row.

Table 7: 1 in 10 Winter Peak Day Gas Shortfall Estimate – 2027 and 2035

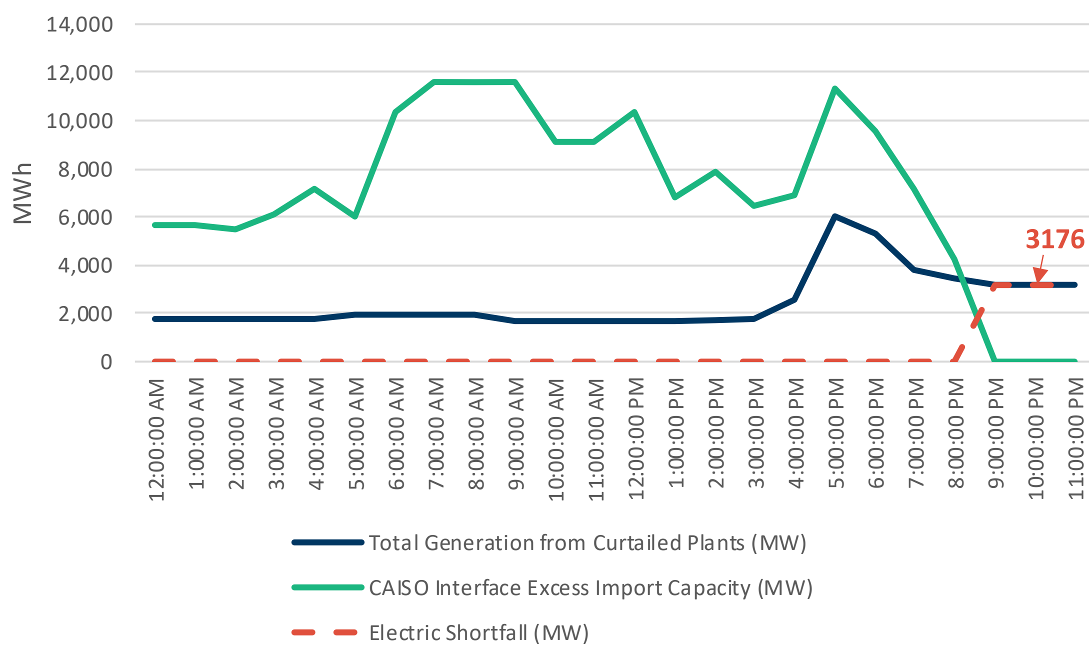
	August 2021 Results	
	54% Inventory	*82% Inventory*
Demand Category	2027	2035
Core	3,101	2,987
Non-Elec Gen Non-Core	670	653
Elec Gen	745	803
Total	**4,516**	**4,443**
Electric Generation (EG) Demand Breakout		
FTI-PLEXOS	621	682
Enhanced Oil Recovery (EOR) Electric	52	50
Refinery Electric	72	71
Total	**745**	**803**
EG Demand Reduction to Balance Model		
Base Requirements (above)	4,516	4,443
Demand Reduction (EG)	(395)	(323)
Total Served in Hydraulic Model	**4,121**	**4,121**

D. Electric Shortfall Calculation

The Electric Shortfall calculation was conducted by examining the most constrained hours for the power system. The constrained hours were identified as those where additional imports of power into CAISO[44] were insufficient to replace generation from gas units that could not source gas due to the 1 in 10 Winter Peak Day gas constraint.

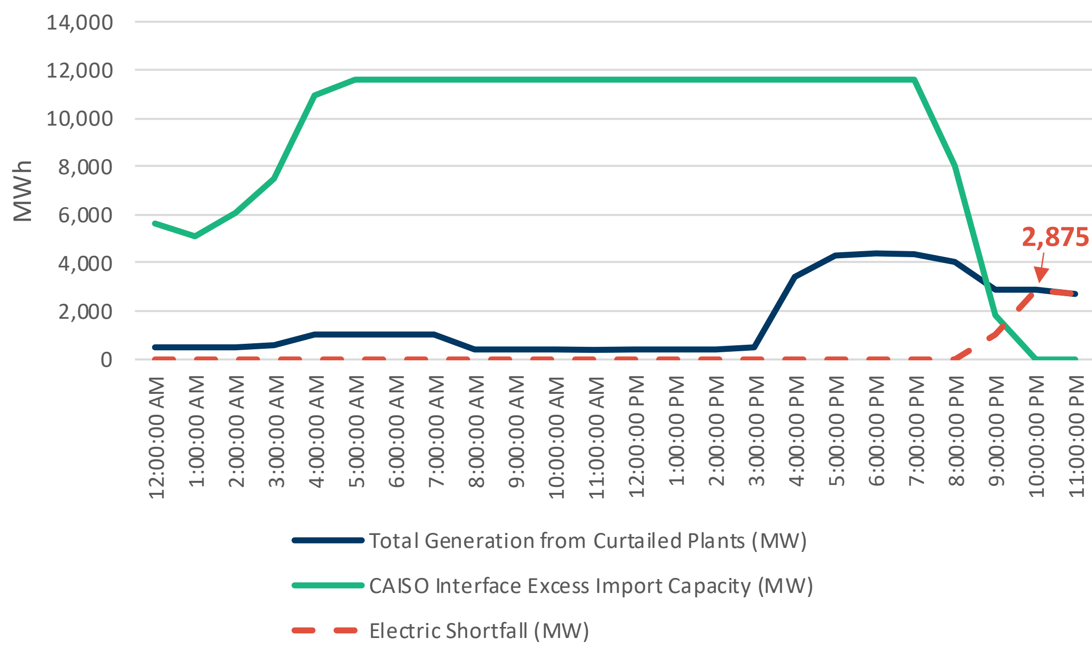
As shown in Figure 8 and Figure 9 below, the Electric Shortfall (orange dotted line) in each of the constrained hours was calculated as the total generation from curtailed plants (blue line) minus the remaining, or yet unused, import capacity into CAISO (green line). The maximum Electric Shortfall is estimated to be 3,176 MW in 2027 and 2,875 MW in 2035 and occurs at 10 PM for both years.

Figure 8: 2027 Electric Shortfall Analysis



[44] A limit of 11,600 MW was used for simultaneous imports into CAISO, consistent with prior CPUC analysis. CPUC Energy Division, *2019-20 IRP: Proposed Reference System Portfolio Validation with SERVM Reliability and Production Cost Modeling*, November 6, 2019

Figure 9: 2035 Electric Shortfall Analysis



IV. Identification and Evaluation of Portfolio Solutions

Investment solutions were identified that could plausibly address the Gas or Electric Shortfall while still maintaining energy and electric reliability for the Los Angeles region and with the intent of maintaining just and reasonable rates. [45]

Four distinct portfolios plus a fifth "hybrid" portfolio, which incorporates certain elements from the four distinct portfolios, were identified based on the following criteria:

- Reflect plausible solutions that are operationally and commercially reasonable
- Adequately address the entire shortfall created by the retirement of Aliso Canyon
- Conform to relevant CPUC Orders and Statutes, including those related to Demand-Side Management and Decarbonization goals

The five portfolios, which were refined in Workstream 2, are as follows:

- **Portfolio 1:** Gas Transmission Expansion – consists of natural gas supply increases either through additional pipeline capacity and/or access to additional storage capacity
- **Portfolio 2:** Gas Demand Reduction – consists of a combination of Building Electrification, energy efficiency, and gas demand response
- **Portfolio 3:** Electric Generator Additions – consists of a set of zero-carbon generating capacity and storage capacity above Base Case levels in proportions based principally on the resource mix expected from the 11.5 GW NQC CPUC order
- **Portfolio 4:** Electric Transmission Additions – consists of transmission lines that increase the CAISO interface and/or increase transmission into Los Angeles Department of Water and Power
- **Portfolio 5:** Hybrid – consists of certain elements from Portfolios 1-4 that cost-effectively address the shortfalls in 2027 and 2035

Each portfolio solution was developed such that the solution would at least meet the projected shortfall. The technical details of each portfolio solution are described in the next main section.

A. Cost-Benefit Evaluation

A cost-benefit analysis was conducted for each portfolio solution. The CBA steps were:

1. Developing capital and operational cost estimates for each solution using market estimates

[45] As ordered by CPUC in Docket No. I170-02-002

2. Conducting electricity (PLEXOS) and gas market (GPCM) modeling to capture how portfolios might affect energy market consumption and prices and thus ratepayer costs or benefits[46]
3. Including the impact of the social cost of carbon
4. Discounting all cost and benefits back to a single reference year of 2019 for comparison using a common project capital recovery factor and social discount rate

Table 8 below lists the primary CBA assumptions that are applied across all portfolio solutions.

Table 8: CBA Financial Assumptions Applied Across the Five Portfolios[47]

Assumption	Value
Capital Recovery Period	20 years
Interest Rate (Nominal / Real)	4.0% / 1.5%
Interest During Construction	4.0%
Return on Equity (Nominal / Real)	9.0% / 6.3%
Debt Fraction	67.1%
Tax Rate (Federal and State)	25.7%
Weighted Average Cost of Capital (Nominal /Real)	5.0% / 2.4%
Depreciation Period	5-year MACRS
Capital Recovery Factor (Nominal / Real)	**7.99% / 6.35%**

The values in Table 8 above are based on the National Renewable Technology Laboratory's ("NREL") 2021 Annual Technology Baseline ("ATB") for land-based wind generation. The real Capital Recovery Factor ("CRF") of 6.35 percent shown in the table represents the culmination of the financial assumptions shown in Table 8 above and was applied in the CBA for each Portfolio to calculate levelized annual costs. The NREL 2021 ATB defines the CRF as "the ratio of a constant annuity to the present value of receiving that annuity for a given length of time."[48]

While actual risks and capital recovery period will vary across technologies and solutions within portfolios, the CRF value of 6.35 percent was applied consistently in this study to avoid any perception of arbitrariness or favoritism towards certain technologies or solutions. Sensitivity analysis of the CRF

[46] PLEXOS modeling was done at the hourly level for all 8,760 hours in each modeled year. GPCM modeling was done at the monthly level for all 12 months in each modeled year.
[47] All values in the table are based on "Land-Based Wind" assuming R&D Financials and a 20-year capital recovery period in the NREL 2021 ATB accessed at: https://data.openei.org/submissions/4129.
[48] Ibid.

showed that changing its value for certain portfolios or solutions had minimal impact on overall CBA results because of each portfolio's technological and capital cost distinctiveness.

Table 9 contains additional, global assumptions applied in the CBA analysis across the five portfolios.[49]

Table 9: Primary CBA Assumptions Applied Across the Five Portfolios

Assumption	Value
Consumer Price Index ("CPI")	Historical from the BLS;[50] Projected from the 2021 Annual Energy Outlook[51]
Social Cost of Carbon (2027 / 2035)	\$57.70 per ton of CO_2 / \$66.20 per Metric Ton of CO_2[52]
Natural Gas CO_2 Emissions Factor	51.2 Metric Tons of CO_2 per MMCF[53]

The CPI was used to adjust all financial results used in the CBA to 2019 dollars. For example, Portfolio 1 relied upon cost inputs from 2011 to 2016, which were then inflated using the CPI to 2019 dollars.

The Social Cost of Carbon ("SCC") was used to assess the costs associated with CO_2 increases or the savings associated with CO_2 reductions for each portfolio.[54] On net, the portfolios examined had either no significant change in CO_2 emissions or a reduction in CO_2 emissions.

The CBA analysis considers the costs, benefits, and the net benefit (benefits less costs) for each portfolio solution. The benefit-cost ratio, which is equal to benefits divided by cost, is also considered.

[49] Unless otherwise footnoted, all values in the table are based on NREL 2021 ATB accessed at: https://data.openei.org/submissions/4129
[50] https://data.bls.gov/timeseries/CUUR0000SA0?years_option=all_years
[51] https://www.eia.gov/outlooks/aeo/data/browser/#/?id=18-AEO2021&cases=ref2021&sourcekey=0
[52] Social Cost of Carbon shown in the table has been converted to 2019 dollars. See 3% discount rate column in Table ES-1 of the following document: https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf
[53] Converted from pounds of CO_2 per MMBTU. https://www.eia.gov/tools/faqs/faq.php?id=73&t=11
[54] Emissions amounts evaluated in this study pertain to all of California, including all electricity imports into the state

V. Evaluation of Portfolio Solutions

A. Portfolio #1: Gas Transmission Expansion

Introduction

The potential Portfolio 1 solutions address the projected shortfall by increasing (i.e., expanding) upstream pipeline capacity into the LA Basin, which would allow for additional natural gas supply to be transported into the region. Two portfolio solutions involving gas infrastructure expansions were evaluated:

1. Portfolio 1a (Northern Zone Expansion): the addition of three distinct pipeline loops in 2027 or one distinct pipeline loop in 2035; and
2. Portfolio 1b (Wheeler Ridge Zone Expansion): the addition of one distinct pipeline loop in either 2027 or 2035

For each gas infrastructure portfolio solution, an expansion of the Quigley Regulator Station would be necessary.[55]

Modeling Framework

The GSC project team utilized its transient hydraulic model of the SoCalGas system to develop and examine potential gas infrastructure portfolio solutions to support deliverability requirements absent Aliso Canyon. As replacement of Aliso Canyon requires receipt of incremental supply quantities, the GSC team focused on receipt locations that fit two base criteria including: (1) locations at which natural gas supply could conceivably become available; and (2) operationally favorable receipt locations on the SoCalGas system because the capability to transport from the Southern Zone to the Northern and Wheeler Ridge Zones is limited. Using these two criteria, GSC elected to evaluate incremental supply receipts into the SoCalGas Wheeler Ridge and Northern Zones assuming supply growth in the Permian basin.[56]

To increase receipts either into the Wheeler Ridge or Northern Zones, capacity would need to be created on the SoCalGas system to transport these natural gas supplies from the receipt points to the market areas currently served by Aliso Canyon. Potential facility expansions to provide this capacity were designed by starting at the receipt point and then expanding into the system as necessary to enable transport of the incremental supply to the ultimate demand locations. While there are many possible combinations of gas transmission expansion investments that could be evaluated, the project

[55] Regulator stations generally consist of valves, pressure reducing equipment and yard piping and are used to regulate natural gas pressures and flows to ensure that pressures are reduced prior to gas flowing from a higher pressure operating area to a lower pressure operating area.

[56] All major receipt points in each zone were considered. Ultimately, the Wheeler Ridge / Kern River points were chosen for the Wheeler Ridge area as this is where PGE can effectuate deliveries and this option provides a storage alternative. Although both North Needles and South Needles provide access to Permian Basin supplies via upstream pipelines, the North Needles points were settled upon. Line 235 (North Needles) has more capacity than Line 3000 (South Needles).

team leveraged its industry experience to identify the most reasonable and least cost solutions. Variables considered include pipeline conditions, new equipment costs and capabilities, and requisite reliability under a 1 in 10 Winter Peak Day.

The results of the hydraulic modeling simulations were assessed against four key criteria which are necessary for a solution to be considered feasible:

1. Delivered volumes must be sufficient to meet all Core, Noncore (Non-EG), and Electric Generation ("EG") demands.
2. System pressures must be maintained below Maximum Allowable Operating Pressures and above Minimum Allowable Operation Pressures.
3. Line Pack must fully recover over a 24-hour period.
4. Supply sources must demonstrate the ability to successfully balance demand variations through the day.

In each of the Portfolio 1a and 1b solutions, these four conditions were met.[57]

Key Inputs and Assumptions

The key inputs and assumptions for Portfolio 1 are consistent with those applied for the Base Case Analysis, as discussed in the Base Case Assessment, with two exceptions.

1. Receipt Point Utilization is assumed to be 95% in the Northern, Southern, and Wheeler Ridge Zones; and
2. Capacity is reserved to offset one unique pipeline outage.

A detailed discussion of the changes to the Base Case assumptions pertaining to Hydraulic Modeling is provided in "Appendix II: Detailed Hydraulic Modeling Results." The impact of these changes on available pipeline supply and storage withdrawal capacity, which were applicable to Portfolio 1, is provided in Table 10 below.

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[57] Isolated San Joaquin Valley pressures fell below minimum allowable operating pressure by approximately 50 psig or less. Although this would normally be considered a failure of the hydraulic model, these results are consistent with those of CPUC in its Phase 2 Scenario S05 2030 Winter Peak (1-in-10) analysis described on Page 38 of the CPUC's Phase 2: Modeling Report which states, in part, "It was therefore concluded that no further operational actions could have resolved this failure. SoCalGas will investigate the San Joaquin Valley and determine whether a system improvement is required." A copy of the CPUC Phase 2 Modeling Report can be found at https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M369/K286/369286397.PDF

Table 10: Available Pipeline Supply and Storage Withdrawal Capacity

2027 – Available Supply / Storage Withdrawals						
Zone	Nominal Pipeline Capacity (MMcf/d)	Base / Shortfall Analysis RPU %	Base / Shortfall Analysis Available Receipt Capacity (MMcf/d)	CPUC Phase 2 Winter RPU 1/ (2030) (MMcf/d)	Portfolio 1A and 1B RPU %	Portfolio 1A / 1B Available Receipts (MMcf/d)
Wheeler Ridge	765	100%	765	765	95%	727
Southern	1,210	85%	1,030	1,030	95%	1,030
Northern	1,590	85%	1,250	1,250	95%	1,510
Total	**3,565**		**3,045**	**3,045**		**3,267**
Local Production			70			70
Total Physical Supply			**3,115**			**3,337**
Storage WD Capacity			**1,033**			**1,033**
Outage Protection			**N/A**			**(212)**
Total Receipts			**4,148**			**4,158**

2035 – Available Supplies / Storage Withdrawals						
Zone	Nominal Pipeline Capacity (MMcf/d)	Base / Shortfall Analysis RPU %	Base / Shortfall Analysis Available Receipt Capacity (MMcf/d)	CPUC Phase 2 Winter RPU 1/ (2030) (MMcf/d)	Portfolio 1A and 1B RPU %	Portfolio 1A / 1B Available Receipts (MMcf/d)
Wheeler Ridge	765	100%	765	765	95%	727
Southern	1,210	85%	1,030	1,030	95%	1,030
Northern	1,590	85%	1,250	1,250	95%	1,510
Total	**3,565**		**3,045**	**3,045**		**3,267**
Local Production			70	70		70
Total Physical Supply			**3,115**	**3,115**		**3,337**
Storage WD Capacity			**1,262**			**1,262**
Outage Protection			**N/A**			**(212)**
Total Receipts			**4,377**			**4,387**

Modeling Results

Portfolio 1a

To address the Shortfall in 2027, the Portfolio 1a expansion solution requires the following gas infrastructure upgrades and new construction:

- A new 48.5-mile loop[58] of 36-inch pipeline from Newberry towards Cajon Junction positioned immediately after the Newberry compressor station
- A new 20-mile loop of 36-inch pipeline from North Needles West towards the Kelso compressor station positioned to start at the discharge of the North Needles compressor station

[58] A pipeline "loop" is a pipeline section laid parallel and connected to the main gas pipeline. A pipeline loop increases the flowing capacity and/or decreases the pressure loss of the system through the looped segment.

- A new 15-mile loop of 36-inch pipeline from the Kelso compressor station to the west positioned to start at the discharge of the Kelso compressor station
- 300 MMCFD capacity expansion at Quigley Regulator Station[59]

These gas infrastructure upgrades would allow for incremental supply receipts of 13 MMCFD at the Topock interconnect with Transwestern and 382 MMCFD at the North Needles interconnect with Transwestern.[60]

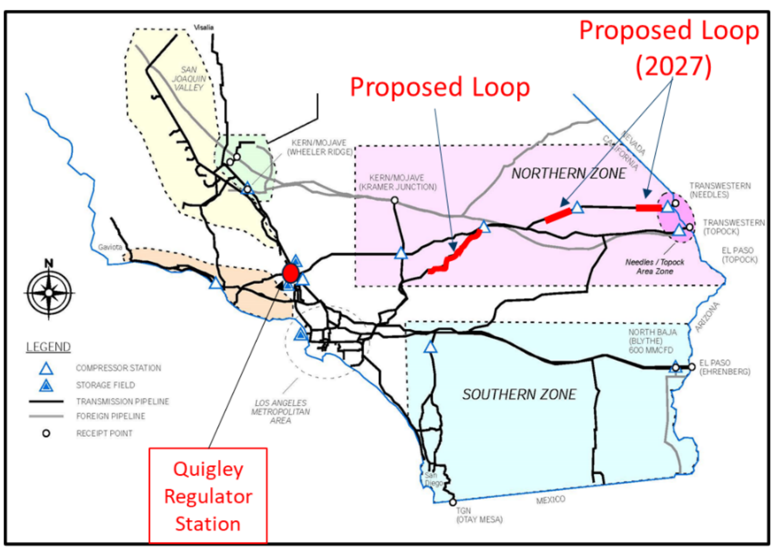
To address the Shortfall in 2035, the Portfolio 1a expansion solution requires the following gas transmission upgrades and new construction:

- A new 41.5-mile loop of 36-inch pipeline from Newberry towards Cajon Junction positioned immediately after the Newberry compressor station
- 300 MMCFD capacity expansion at Quigley Regulator Station

These gas infrastructure upgrades would allow for incremental supply receipts of 13 MMCFD at the Topock interconnect with Transwestern and 300 MMCFD at the North Needles interconnect with Transwestern.

Figure 10 and Figure 11 provide system maps marking the geographic locations of the facilities considered for expansion in the Portfolio 1a solution for 2027 and 2035, respectively.

Figure 10: Map Indicating Portfolio 1a Expansions for 2027



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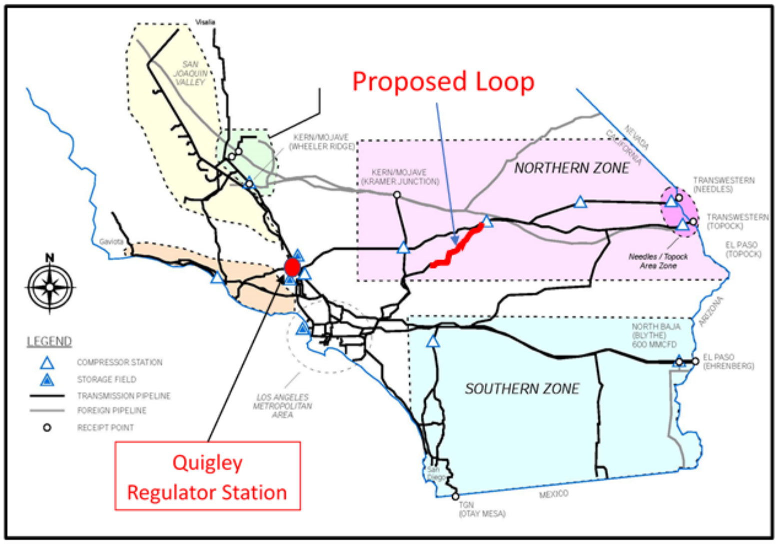
[59] 300 MMCFD is consistent with prior SoCalGas estimates of the amount of capacity expansion at Quigley Regulator Station that would be required to support similar pipeline expansion projects as those considered in the Portfolio 1 solution.
[60] The Portfolio 1a solution assumes that incremental supplies at the North Needles and Topock Border receipt points are available.

Figure 11: Map Indicating Portfolio 1a Expansions for 2035



Portfolio 1b

To address the Shortfall in 2027, the Portfolio 1b expansion solution requires the following gas transmission upgrades and new construction:

- A new 34.5-mile loop of 36-inch pipeline extending from the Wheeler Ridge receipt point south towards the Quigley Regulator Station[61]
- 300 MMCFD capacity expansion at Quigley Regulator Station

These gas infrastructure upgrades would allow for incremental supply receipts of 395 MMCFD off the Wheeler Ridge receipt point.[62]

To address the Shortfall in 2035, the Portfolio 1b expansion solution requires the following gas transmission upgrades and new construction:

- A new 24.8-mile loop of 36-inch pipeline extending from the Wheeler Ridge receipt point south towards the Quigley Regulator Station
- 300 MMCFD capacity expansion at Quigley Regulator Station

These gas infrastructure upgrades would allow for incremental supply receipts of 313 MMCFD off the Wheeler Ridge receipt point.

[61] California Gas Transmission lists delivery capacity of 647 MMCFD to SoCalGas at Kern River Station, and history indicates that rarely is more than 200 MMCFD utilized during winter months. The unutilized capacity of 447 MMCFD is greater than the projected shortfall in both 2027 and 2035.

[62] The Portfolio 1b solution assumes additional supply is available in the form of storage withdrawals from PGE storage facilities such as Gill Ranch

Figure 12 and Figure 13 provide system maps marking the geographic locations of the facilities considered for expansion in the Portfolio 1b solution in 2027 and 2035, respectively.

Figure 12: Map Indicating Portfolio 1b Expansions in 2027

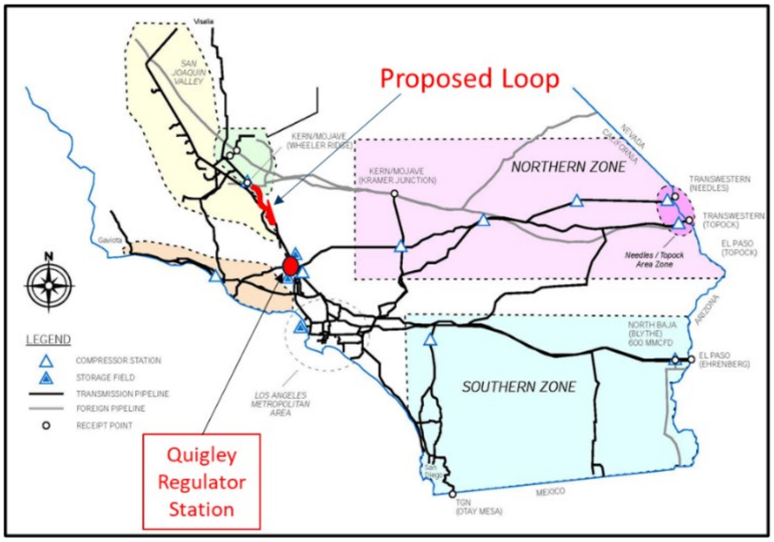
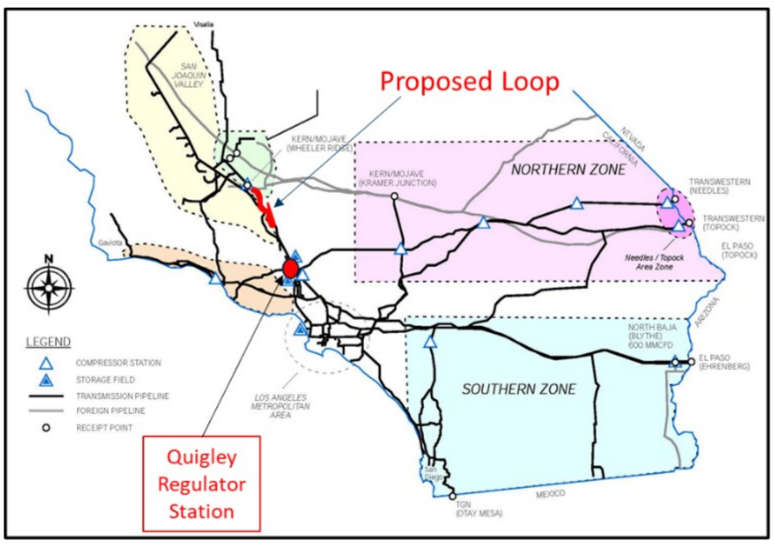


Figure 13: Map Indicating Portfolio 1b Expansions in 2035



Cost-Benefit Analysis

Portfolio 1a

The Portfolio 1a solution is estimated to incur $100 million in annual costs if Aliso Canyon were retired in 2027 and $67 million in annual costs if Aliso Canyon were retired in 2035. Portfolio 1a's levelized annual costs are comprised of the estimated costs of constructing new pipeline loops and expanding the Quigley Regulator Station, as well as incremental firm transportation capacity costs necessary to transport additional pipeline gas.

Levelized annual benefits are assumed to be $0 due to the fact that the Portfolio 1a solution would directly offset the peak day gas supply that would have been sourced from Aliso Canyon absent its retirement. As there were no changes to forecasted gas or electric loads for this portfolio solution, there would be little to no increase in Greenhouse Gas ("GHG") emissions. As such, Portfolio 1a is estimated to have a net benefit of -$100 million if Aliso Canyon is retired in 2027 and a net benefit of -$67 million if Aliso Canyon is closed in 2035.

A breakdown of the Portfolio 1a investment costs by retirement year and the Portfolio 1a cost benefit summary are provided below in Table 11 and Table 12, respectively. Portfolio 1a cost-benefit analysis is further detailed in "Appendix III: Detailed Financial Modeling Results."

Table 11: Portfolio 1a Levelized Annual Investment Costs (2019$)

	2027	2035
Levelized Annual Investment Cost	**$100,421,000**	**$66,783,000**
Firm Transportation Capacity	$52,195,000	$42,705,000
Gas Infrastructure	$48,226,000	$24,078,000
Pipelines	$48,009,000	$23,861,000
Pressure Limiting Station	$217,000	$217,000

Table 12: Portfolio 1a Cost-Benefit Summary (2019$'s)

	2027	2035
Total Annual Cost	**$100,421,000**	**$66,783,000**
Total Investment Cost	$100,421,000	$66,783,000
Electricity Cost Increase	$0	$0
CA CO_2 Emissions Increase - Electricity	$0	$0
Gas Cost Increase	$0	$0
CA CO_2 Emissions Increase - Gas	$0	$0
Total Annual Benefits	**$0**	**$0**
Electricity Cost Reduction	$0	$0
CA CO_2 Emissions Reduction - Electricity	$0	$0
Gas Cost Reduction	$0	$0
CA CO_2 Emissions Reduction - Gas	$0	$0
Resource Adequacy Increase	$0	$0
Total Net Benefit	**($100,421,000)**	**($66,783,000)**
Benefit-Cost Ratio	**N/A**	**N/A**

Portfolio 1b

The investments pertaining to gas transmission expansion in the Wheeler Ridge Zone that would be necessary to meet the Shortfall are estimated to have a net benefit of -$147 million if Aliso Canyon is retired in 2027, and a net benefit of -$118 million if Aliso Canyon is closed in 2035.

The Portfolio 1b levelized total annual costs are comprised of the estimated costs of constructing new pipeline loops, expanding the Quigley Regulator Station, incremental storage costs, and upstream pipeline capacity costs. As was the case with Portfolio 1a, levelized total annual benefits are assumed to be $0 as the Portfolio 1b solution would directly offset the peak day gas supply that would have been sourced from Aliso Canyon absent retirement. As there were no changes to projected gas or electric loads, no significant impact related to GHG emissions is assumed.

A breakdown of the Portfolio 1b investment costs by retirement year and the Portfolio 1b cost benefit summary are provided below in Table 13 and Table 14, respectively. Portfolio 1a cost-benefit analysis is further detailed in "Appendix III: Detailed Financial Modeling Results."

Table 13: Portfolio 1b Levelized Annual Investment Costs (2019$)

	2027	2035
Total Annual Costs	**$147,282,000**	**$118,255,000**
Firm Transportation Capacity	$105,485,000	$86,140,000
Storage Capacity	$21,571,000	$17,639,000
Gas Infrastructure	$20,226,000	$14,476,000
Pipelines	$20,009,000	$14,259,000
Pressure Limiting Station	$217,000	$217,000

Table 14: Portfolio 1b Cost-Benefit Summary (2019$'s)

	2027	2035
Total Annual Cost	**$147,282,000**	**$118,255,000**
Total Investment Cost	$147,282,000	$118,255,000
Electricity Cost Increase	$0	$0
CA CO_2 Emissions Increase - Electricity	$0	$0
Gas Cost Increase	$0	$0
CA CO_2 Emissions Increase - Gas	$0	$0
Total Annual Benefits	**$0**	**$0**
Electricity Cost Reduction	$0	$0
CA CO_2 Emissions Reduction - Electricity	$0	$0
Gas Cost Reduction	$0	$0
CA CO_2 Emissions Reduction - Gas	$0	$0
Resource Adequacy Increase	$0	$0
Total Net Benefit	**($147,282,000)**	**($118,255,000)**
Benefit-Cost Ratio	**N/A**	**N/A**

B. Portfolio #2: Gas Demand Reduction

Introduction

The potential solution evaluated in Portfolio 2 addresses the projected Shortfall through the implementation of policies and programs aimed primarily at reducing gas demand, with specific emphasis on peak day reductions. Portfolio 2 incorporates the following three components, each of which is discussed in further detail below:

- Building Electrification
- Energy Efficiency
- Gas Demand Response

Modeling Framework

The structure of the Portfolio 2 solution differs from the other Portfolio solutions considered in two notable respects:

1. Portfolio 2 incorporates demand-side solutions, where the projected shortfall is addressed through a reduction in the amount of energy consumed, while the other Portfolios consider only supply-side solutions, where the projected shortfall is addressed through an increase in the amount of energy that is available for consumption.
2. Portfolio 2 evaluates the combined impact of three separate and distinct components rather than a single investment strategy.

For the purposes of constructing the framework of the Portfolio 2 solution, the Project Team first evaluated the projected potential change in energy demand as a function of Building Electrification and Energy Efficiency measures in order to develop adjusted load patterns. Next, the new load patterns were evaluated and run through the Project Team's modeling software in order to calculate the remaining shortfall after accounting for all Electrification and Energy Efficiency impacts, using the same methodology as was used to determine the base case Shortfall, described in "Section III.C. Base Case Modeling Key Inputs and Results." Lastly, the remaining shortfall was compared against potentially available gas demand response in order to estimate and evaluate the relative level of participation in gas demand response programs necessary to meet the remaining shortfall.

Key Inputs and Assumptions

Building Electrification

Building Electrification aims to reduce both gas and overall energy demand through the conversion of gas-fueled water and space heating equipment to electric-fueled equipment. The impact of increased electrification assumed in the Portfolio 2 solution is based on the "Moderate Electrification" scenario in the California Energy Commission's 2021 California Building Decarbonization Assessment Final Report

("2021 CEC Report").[63] This scenario was chosen over the "Aggressive Electrification" scenario primarily due to the significant cost differential between the two, where the costs for the "Aggressive Electrification" scenario were assessed to be prohibitively high.[64]

Moderate Case results are presented in cumulative impacts through 2030 in the 2021 CEC Report. For this study, it was assumed that the cumulative impacts in 2035 would not be materially different than the 2030 impacts presented in the 2021 CEC Report as FTI had no basis with which to forecast impacts for 2035. The cumulative impacts in 2027 were estimated at 53 percent of the 2030 cumulative totals based on a comparison of the cumulative reduction in emissions through 2027 and total cumulative emissions reductions through 2030, as shown in Table 15 below.

Table 15: Moderate Case Building Sector Emissions[65]

	Moderate Case
2020 Emissions (MMTCO2e)	34.0
2027 Emissions (MMTCO2e)	31.0
2030 Emissions (MMTCO2e)	28.3
Cumulative Emissions Change, 2020 to 2030	(5.7)
Cumulative Emissions Change, 2020 to 2027	(3.0)
2027 Percentage	**53%**

The gas demand impacts of Building Electrification specific to SoCalGas and SDG&E service territories were estimated at 220 MMCFD in 2027 and 419 MMCFD in 2035 based on the company specific projections for the Baseline and Moderate Cases within the 2021 CEC Report, as shown in Table 16 below.

[63] The CEC's "Moderate Electrification" scenario assumes that all new construction will be fully electrified by 2030; 50 percent of gas space and water heating appliances will be replaced with electric appliances at end of life, and 5 percent of gas appliances in existing buildings will be replaced with electric appliances before the end of their useful lives (pp 44-45).
[64] Per the 2021 California Building Decarbonization Assessment Final Report, the "Moderate Electrification" scenario is one-sixth the costs of the "Aggressive Electrification" scenarios, which have higher costs primarily because the respective higher penetration of gas appliances replaced before burnout significantly increases electrification costs.
[65] *2021 CEC Report*, Table C-17

Table 16: Moderate Case Gas Demand Reductions

	2027	2035
Baseline Annual Gas Demand (SoCalGas & SDG&E), MMTherms	3,850	3,850
Moderate Scenario Annual Gas Demand (SoCalGas & SDG&E), MMTherms	2,270	2,270
Reduction in Annual Gas Demand (SoCalGas & SDG&E), MMTherms	1,580	1,580
Reduction in Annual Average Gas Demand (SoCalGas & SDG&E), conversion to MMCFD[66]	419	419
Percentage of Savings Achieved by Target Year	53%	100%
Target Year Reduction in Annual Average Gas Demand (SoCalGas & SDG&E), MMCFD	**220**	**419**

In order to isolate the electric demand impacts of Building Electrification that were specific to the SoCalGas and SDG&E service territories, the electric demand impacts pertaining to all of California were adjusted based on the percentage of SoCalGas and SDG&E annual gas demand out of total California gas demand, as shown in Table 17 below.

Table 17: SoCalGas and SDG&E Share of Total California Electric Demand

	Moderate Case
Moderate Scenario Annual Gas Demand (All California), MMTherms	4,044
Moderate Scenario Annual Gas Demand (SoCalGas & SDG&E), MMTherms	2,270
SoCalGas and SDG&E Share of Total California	**56%**

The increase in total electric demand specific to SoCalGas and SDG&E was estimated at 6,757 GWh in 2027 and 12,846 GWh in 2035, as shown in Table 18 below.

Table 18: Portfolio 2 Incremental Electric Demand

	2027	2035
2030 Increase in Total Electric Demand (All California), GWh	22,885	22,885
SoCalGas and SDG&E Share of Total California	56%	56%
2030 Increase in Total Electric Demand (SoCalGas and SDG&E), GWh	12,846	12,846
Percentage of Savings Achieved by Target Year	53%	100%
Portfolio 2 Increase in Total Electric Demand (SoCalGas and SDG&E), GWh	**6,757**	**12,846**

[66] Annual volumes (MMTherms) converted to daily volumes (MMCFD) by dividing annual volume by 365 days per year and applying conversion factor of 1.0336 Therms per CCF.

The total projected reduction in gas demand calculated in Table 16 and the total projected increase in electric demand calculated in Table 18 were further adjusted to isolate the demand impacts that would result in an offset in gas demand by end-use. For the purposes of this study, Residential and Commercial HVAC and water heating were the end-uses assumed to meet this criterion.

The percentage of incremental electric demand pertaining to these end-uses was estimated at approximately 79 percent, and the corresponding gas demand reduction was estimated at approximately 69 percent based on the Moderate Case end-use analysis included in the 2021 CEC Report.[67] In both cases, approximately 80 percent of the applicable impacts were associated with Residential electrification, with the remaining 20 percent associated with Commercial electrification.[68]

The applicable incremental electric demand evaluated in Portfolio 2 was estimated at 5,338 GWh in 2027 and 10,148 GWh in 2035, as shown in Table 19 below.

Table 19: Portfolio 2 Increase in Applicable Electric Demand

	2027	2035
Portfolio 2 Increase in Total Electric Demand (SoCalGas and SDG&E), GWh	6,757	12,846
Percentage of Increase in Total Electric Demand Associated With Residential & Commercial Space and Water Heating	79%	79%
Portfolio 2 Increase in Applicable Electric Demand (SoCalGas and SDG&E), GWh	**5,338**	**10,148**

The applicable reduction in gas demand evaluated in Portfolio 2 was estimated at 152 MMCFD in 2027 and 289 MMCFD in 2035, as shown in Table 20.

Table 20: Portfolio 2 Reduction in Applicable Gas Demand

	2027	2035
Portfolio 2 Reduction in Total Gas Demand (SoCalGas and SDG&E), MMCFD	220	419
Percentage of Increase in Total Electric Demand Associated With Residential & Commercial Space and Water Heating	69%	69%
Portfolio 2 Decrease in Relevant Gas Demand (SoCalGas and SDG&E), MMCFD	**152**	**289**

The annual applicable increase in electric demand was allocated to an hourly pattern as follows:[69]

[67] 2021 CEC Report, Figure 21
[68] Ibid.
[69] Electrification impact analysis is provided as a supplemental material in the file 'Electrification 2027 & 2035 – Gas and Electric Demand Impacts.xlsx'

1. The incremental annual electric load was converted to a daily frequency based on normal (average) daily temperature patterns for the Los Angeles region.
2. The incremental daily electric load was converted to an hourly frequency based on the end-use and customer segment specific hourly load shapes incorporated in the 2021 CEC Report.

The annual applicable decrease in gas demand was allocated to an hourly pattern as follows:

1. The annual reduction in gas demand was converted to a daily frequency based on the relationship (linear regression) between temperature and SoCalGas core residential and commercial demand, as derived from SoCalGas forecasts under normal weather conditions reported in the 2020 California Gas Report.
2. The daily gas demand reduction was converted to an hourly frequency based on the end-use and customer segment specific hourly load patterns used to allocate incremental electric demand, as described above.

These hourly patterns were used in the calculation of the 1 in 10 Winter Peak Day impacts of Building Electrification in combination with Energy Efficiency impacts, as discussed below in "Portfolio 2, 1 in 10 Winter Peak Day Impacts."

Energy Efficiency

For the Portfolio 2 solution, incremental Energy Efficiency savings were based on the 2021 Energy Efficiency Potential and Goals Study prepared by Guidehouse Inc. for the CPUC ("2021 Guidehouse Study"). The 2021 Guidehouse Study evaluates multiple scenarios that were developed in collaboration with the CPUC. The scenario chosen for evaluation in the Portfolio 2 solution was Scenario 3, the Total Resource Cost ("TRC") High scenario. The TRC High scenario reflects aggressive Energy Efficiency goals consistent with California's long term decarbonization goals.

To evaluate annual incremental gas Energy Efficiency, projected savings from the 2021 Guidehouse Study were compared to the gas Energy Efficiency projections pertaining to the SoCalGas and SDG&E base case demand forecasts in the 2020 California Gas Report. These levels were comparable, indicating that the TRC High case level of gas energy efficiency is already reflected in the Base Case, and thus no incremental gas Energy Efficiency savings were assumed in the Portfolio 2 solution.

The normal weather annual reduction in electric demand due to electric Energy Efficiency savings was calculated based on a comparison of the results of the 2021 Guidehouse Study to the electric Energy Efficiency projections pertaining to the base case demand forecasts in the 2019 Integrated Energy

Policy Report ("2019 IEPR").[70] The normal weather annual reduction in electric demand was converted to an hourly frequency based on the hourly patterns provided in the 2019 IEPR.[71]

Portfolio 2, 1 in 10 Winter Peak Day Impacts

The 1 in 10 Winter Peak Day net impact of electric Energy Efficiency savings and Building Electrification on gas fired generation demand was assessed as follows:

1. The normal weather hourly reductions in electric demand pertaining to electric Energy Efficiency savings and the normal weather hourly increases in electric demand pertaining to Building Electrification were summed into a single hourly pattern reflecting the net change in electric demand.
2. The scaled net change in electric demand was input into PLEXOS and added to the scaled Base Case electric demand.
3. Next, a new market simulation was performed in PLEXOS.
4. The resulting revised gas-fired Electric Generation demand under 1 in 10 Winter Peak Day conditions were compared to Base Case results to calculate the net change in gas-fired Electric Generation demand.

The 1 in 10 Winter Peak Day impacts of Building Electrification related to decreased gas heating demand were assessed as follows:

1. The highest daily demand during an average weather year was identified from the daily patterns described above.
2. The Los Angeles region average temperature on that day was identified using the same daily patterns.
3. The relationship (linear regression) between temperature and demand described above was used to increase this daily demand to reflect the temperature on a 1 in 10 Winter Peak Day, using the SoCalGas 1 in 10 Winter Peak Day temperature from the 2020 California Gas Report.

The total 1 in 10 Winter Peak Day impacts in 2027 and 2035 of Building Electrification and electric Energy Efficiency on the Gas Shortfall, expressed in MMCFD, are presented in Table 21 below.

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[70] The 2019 Integrated Energy Policy Report covers a broad range of topics, including decarbonizing buildings, integrating renewables, energy efficiency, energy equity, integrating renewable energy, updates on Southern California electricity reliability, climate adaptation activities for the energy sector, natural gas assessment, transportation energy demand forecast, and the California Energy Demand Forecast.

[71] Electric energy efficiency calculations are provided as a supplemental material in the file "Energy Efficiency Calculations 2027 and 2035.xlsx"

Table 21: Portfolio 2 Building Electrification and Electric Energy Efficiency Impact on Shortfall

	2027	2035
Shortfall (MMCFD)	395	323
Increased Electric Generation Demand (MMCFD)	20	54
Decreased Gas Heating Demand (MMCFD)	(348)	(492)
Remaining Shortfall (MMCFD)	**67**	**(115)**

Gas Demand Response

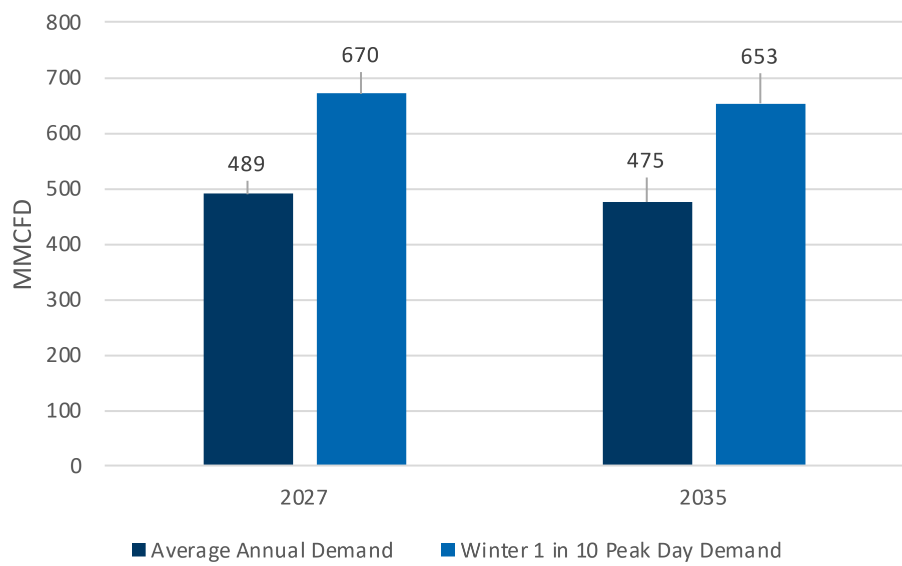
The goal of Demand Response policies and programs is to achieve load reductions over specific time periods through either load shifting or load shedding[72] in response to market signals. The Noncore Commercial and Industrial ("C&I") customer segment includes very large industrial customers, such as refineries, whose participation in a Demand Response program could substantially reduce total system demand.[73] Gas demand response as considered here focuses on commercial and industrial customers.

The potential load reduction available through Gas Demand Response considered in Portfolio 2 was estimated as 670 MMCFD in 2027 and 653 MMCFD in 2035, based on 1 in 10 Winter Peak Day demand projections for the SoCalGas and San Diego Gas and Electric Noncore C&I customer segment contained within the 2020 California Gas Report and accompanying workpapers, as shown in Figure 14 below.

[72] Load shifting refers to changes in customer consumption patterns such that load is 'shifted' from one time period to another, typically over a short period such as a single day, with no change to overall consumption. Load shedding refers to changes in customer consumption patterns such that load is 'shed' or curtailed, resulting in a decrease in total consumption.

[73] https://www.socalgas.com/regulatory/documents/a-18-11-005/Demand_Response_Testimony_Chapter%201_Final.pdf

Figure 14: Portfolio 2 Noncore C&I Daily Demand



A key consideration in the design of any demand response program is performance reliability. A potential means to address the need for high performance reliability is incorporating some level of direct load control, where program administrators have the ability to physically reduce gas flows at customers' meters after providing advance notification to the customer within a pre-determined window of time.

Customer participation in a Demand Response program featuring direct load control would be highly dependent on the expected economic benefits, which would vary from customer to customer. Noncore C&I customers, particularly those with the highest projected peak day demands, should be consulted directly in a collaborative program development process with the goal of achieving the highest level of demand reduction while ensuring necessary performance reliability.

In order to evaluate the amount of potentially available demand reduction and the cost of such reductions, a possible mechanism that could be employed is a reverse auction. Reverse auctions are a commonly used tool for utility supply procurement and could likely be operated in a similar manner to existing procurement activities. In a potential Demand Response reverse auction, customers would be invited to bid quantities of demand reduction at a given price. Furthermore, an auction could be conducted in real time with the inclusion of limited price discovery, for example displaying to all bidders the lowest current bid price to increase the probability of a successful auction.

Discussion of comparable Gas Demand Response programs evaluated in this study, including costs, program structures, and participation metrics, is provided in "Appendix III: Detailed Financial Modeling Results."

Modeling Results

As shown in Table 21 above, the remaining Shortfall after accounting for the impacts of Building Electrification and Energy Efficiency savings represents approximately 10 percent of Noncore 1 in 10 Winter Peak Day demand in 2027. In 2035, Building Electrification and Electric Energy Efficiency adequately address the Gas Shortfall and Noncore Demand Response is not required.

Cost-Benefit Analysis

In the Portfolio 2 solution, which evaluates with a combination of Building Electrification, Energy Efficiency, and Noncore Gas Demand response in amounts necessary to meet the Shortfall, the levelized annual costs are $198 million in 2027 and $644 million in 2035.[74]

Investment costs are comprised of cost reductions from Building Electrification based on the 2021 CEC Report,[75] cost increases from Energy Efficiency based on the 2021 Guidehouse Study,[76] and estimated Gas Demand Response program costs based on FTI analysis of comparable existing programs, as discussed above. Additional costs pertaining to electricity cost increases and the increase in CO_2 Emissions related to increased Electric Generation were based on PLEXOS production cost modeling. The levelized annual benefits of $247 million in 2027 and $194 million in 2035 are comprised of gas cost reductions and the decrease in CO_2 Emissions related to reduced gas usage based on PLEXOS production cost modeling. The projected increase in CO_2 Emissions due to increased Electric Generation are more than offset by the decrease in CO_2 Emissions due to reduced gas usage, resulting in a net reduction in CO_2 Emissions in both 2027 and 2035.

A breakdown of the Portfolio 2 investment costs by retirement year and the Portfolio 2 cost benefit summary are provided below in Table 22 and Table 23, respectively. Portfolio 2 cost-benefit analysis is further detailed in “Appendix III: Detailed Financial Modeling Results.”

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[74] The Portfolio 2 increase in electricity costs is substantially higher in 2035 compared to 2027 because unlike the other Portfolios evaluated, Portfolio 2 does not include the development of any new generation or transmission resources. As such, the marginal cost for each unit of electricity added increases with additional demand. In the 2027 Portfolio 2 solution, as compared to the Base Case, annual electric demand increases by 0.5 percent and the annual average price increases by 0.8 percent, while in the 2035 Portfolio 2 solution, annual electric demand increases by 1 percent and the annual average price increases by 3.2 percent.

[75] The 2021 CEC Report estimates that deferred costs for new gas equipment exceed the incurred costs for new electric equipment, resulting in negative net investment costs for Building Electrification.

[76] Incremental investment costs necessary to achieve the TRC High Case savings were estimated based on the delta between cumulative program costs for the TRC High Case and the “business-as-usual” TRC Reference Case in 2027 and 2035.

Table 22: Portfolio 2 Levelized Annual Investment Costs (2019$)

	2027	2035
Total Annual Costs	**$4,138,000**	**($23,442,000)**
Electrification	($22,113,000)	($42,041,000)
Energy Efficiency	$9,154,000	$18,599,000
Noncore Demand Response	$17,097,000	$0

Table 23: Cost-Benefit Summary for Portfolio 2 (2019$)

	2027	2035
Total Annual Cost	**$197,912,000**	**$644,293,000**
Total Investment Cost	$4,138,000	($23,442,000)
Electricity Cost Increase	$182,084,000	$629,313,000
CA CO_2 Emissions Increase - Electricity	$11,690,000	$38,422,000
Gas Cost Increase	$0	$0
CA CO_2 Emissions Increase - Gas	$0	$0
Total Annual Benefits	**$247,310,000**	**$193,562,000**
Electricity Cost Reduction	$0	$0
CA CO_2 Emissions Reduction - Electricity	$0	$0
Gas Cost Reduction	$128,491,000	$89,894,000
CA CO_2 Emissions Reduction - Gas	$118,819,000	$103,668,000
Resource Adequacy Increase	$0	$0
Total Net Benefit	**$49,398,000**	**($450,731,000)**
Benefit-Cost Ratio	**1.25**	**0.30**

C. Portfolio #3: Generator Additions

Introduction

The potential Portfolio 3 solution addresses the projected Shortfall through the addition of new zero-emissions electric generation resources within California. The resources considered include wind, solar, geothermal, battery storage, and hybrid resources, i.e., solar/battery storage and wind/battery storage. Portfolio 3 builds off the planned generation resource additions recently incorporated into the base case scenario, as described in "Section III.A. Base Case Development," increasing the capacity of most new generation resources on a pro rata basis in the amount necessary to meet the shortfall.

Modeling Framework

The first step in sizing the Portfolio 3 solutions was to refer to the Electric Shortfall calculation on page 25 of this report. A graphical representation of that analysis from that section is reproduced below for 2027 and 2035.

Figure 15: Base Case 2027 Electric Shortfall Analysis

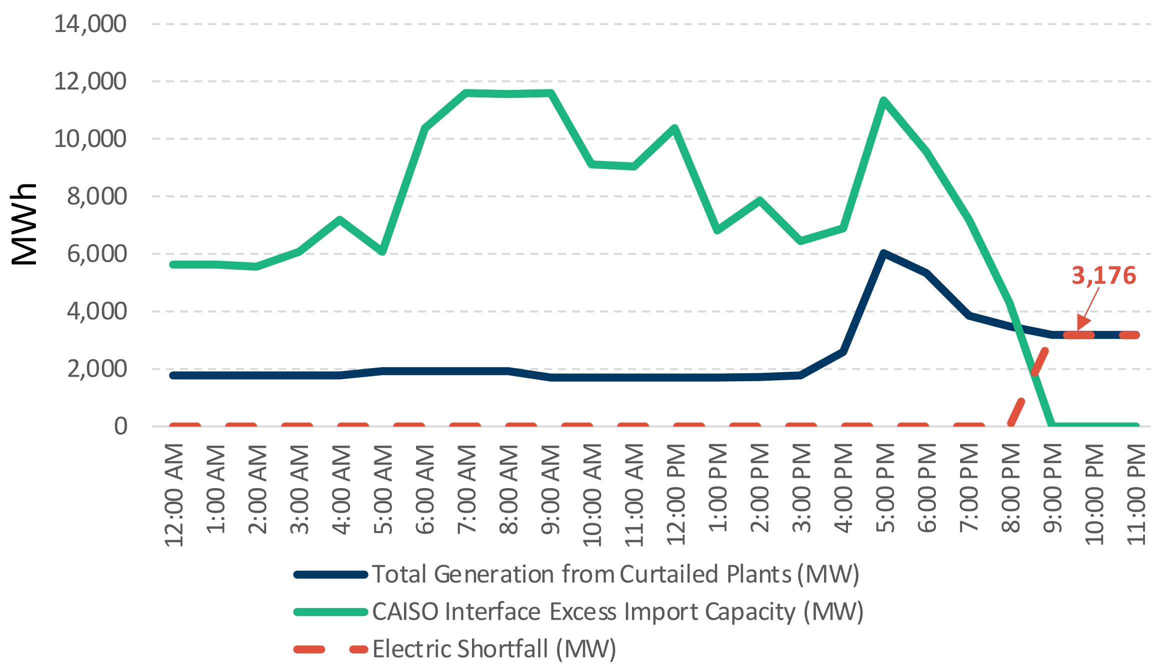
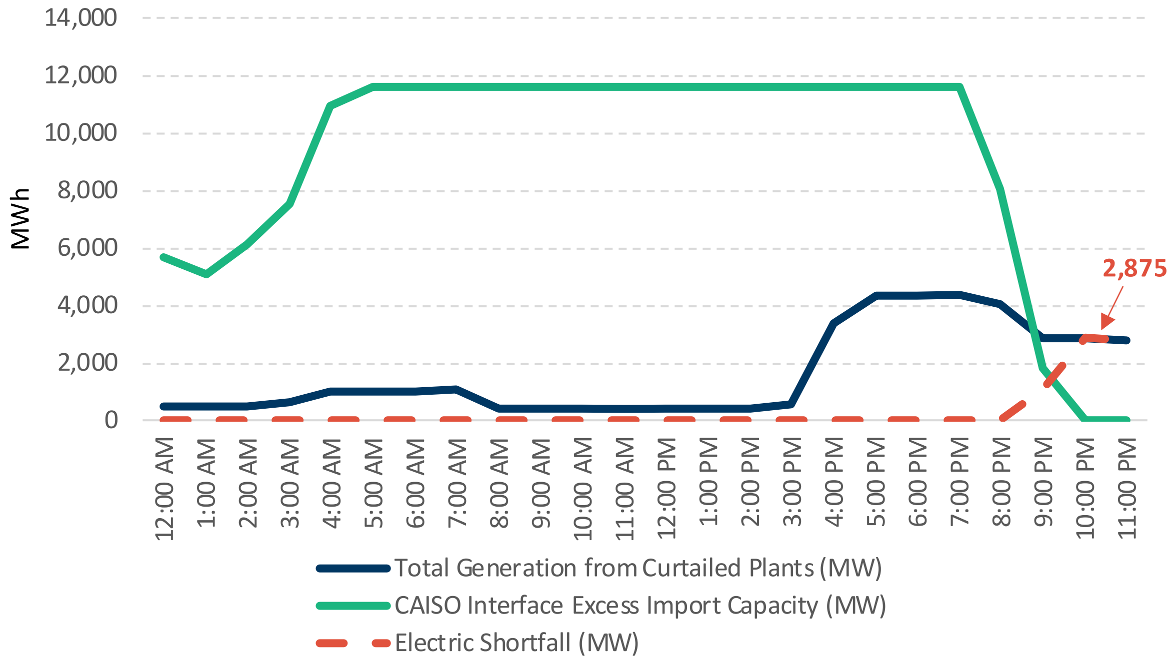


Figure 16: Base Case 2035 Electric Shortfall Analysis



This electric shortfall is the basis for determining the output needed from the Portfolio 3 generation solutions in the constrained hours. For 2027, this amounts to 3,176 MWh in the final three hours of the winter peak day. For 2035, the generation required from the portfolio is less, at 2,875 MWh.

Next, analysis of the 11.5 GW Procurement Order was used to determine what generating technologies would be desirable to include in the portfolio. As there is a current and projected excess of solar generation and solar generation would not directly provide power during the most constrained nighttime hours, it was excluded from the mix, leaving geothermal, wind generation, and both four-hour (4h) and eight-hour (8h) standalone storage.

Table 24 below shows the share of each technology's nameplate capacity in the analysis of the 11.5 GW Procurement Order analysis, excluding solar. These shares were used as the basis to add additional capacity (beyond the 11.5 GW procurement order builds, which are incorporated into the Base Case) for Portfolio 3. Effective Load Carrying Capabilities (ELCCs) provided by the CPUC were used to convert the Net Qualifying Capacity (NQC) figures presented in the 11.5 GW Procurement Order to nameplate capacities. Hybrid wind was decomposed into its component parts (Wind + 4h Storage) for clarity.

Table 24: Portfolio 3 Nameplate Capacity Shares

Resource	Capacity Share (Percent of Nameplate)
Geothermal	10.6%
8h Storage	9.4%
4h Storage	45.4%
Wind	34.5%

Each resource was assessed by its ability to contribute power during the most constrained hours. For wind, this was done by assessing the average capacity factor during the most constrained hours. Geothermal capacity was assumed able to contribute based on an annual average capacity factor of 90 percent. Both 4h and 8h storage technologies were assumed to provide maximum output during the most constrained electric system hours. This was a reasonable assumption given California's excess solar production during the day (i.e., Duck Curve), which is an optimal time for charging storage, and given storage likely would discharge during peak hours.

With the capacity factor assumptions and percent share of nameplate capacity assumptions fixed, the overall size of the generation portfolios was solved for to provide generation equal to the Electric Shortfall in both 2027 and 2035. The resulting nameplate capacities of the Portfolio 3 solutions are displayed below in Table 25 and Table 26.

Table 25: 2027 Portfolio 3 Nameplate Capacities and Contribution to Peak Hour

Resource	Capacity (Nameplate MW)	Contribution to Peak Hour (MW)
Geothermal	460	368
8h Storage	409	409
4h Storage	1,968	1,968
Wind	1,497	431
Total	**4,335**	**3,176**

Table 26: 2035 Portfolio 3 Nameplate Capacities and Contribution to Peak Hour

Resource	Capacity (Nameplate MW)	Contribution to Peak Hour (MW)
Geothermal	416	370
8h Storage	370	370
4h Storage	1,781	1,781
Wind	1,355	390
Total	**3,923**	**2,875**

Figure 17 below shows the production from the generator additions on the 1 in 10 Winter Peak Day in 2027 where geothermal capacity produces at a 90 percent capacity factor, wind produces according to the average generation profile from NREL, and 4h and 8h storage are assumed to provide maximum output during the most constrained electric system hours.

Figure 17: Portfolio 3 Production from 2027 Generator Additions

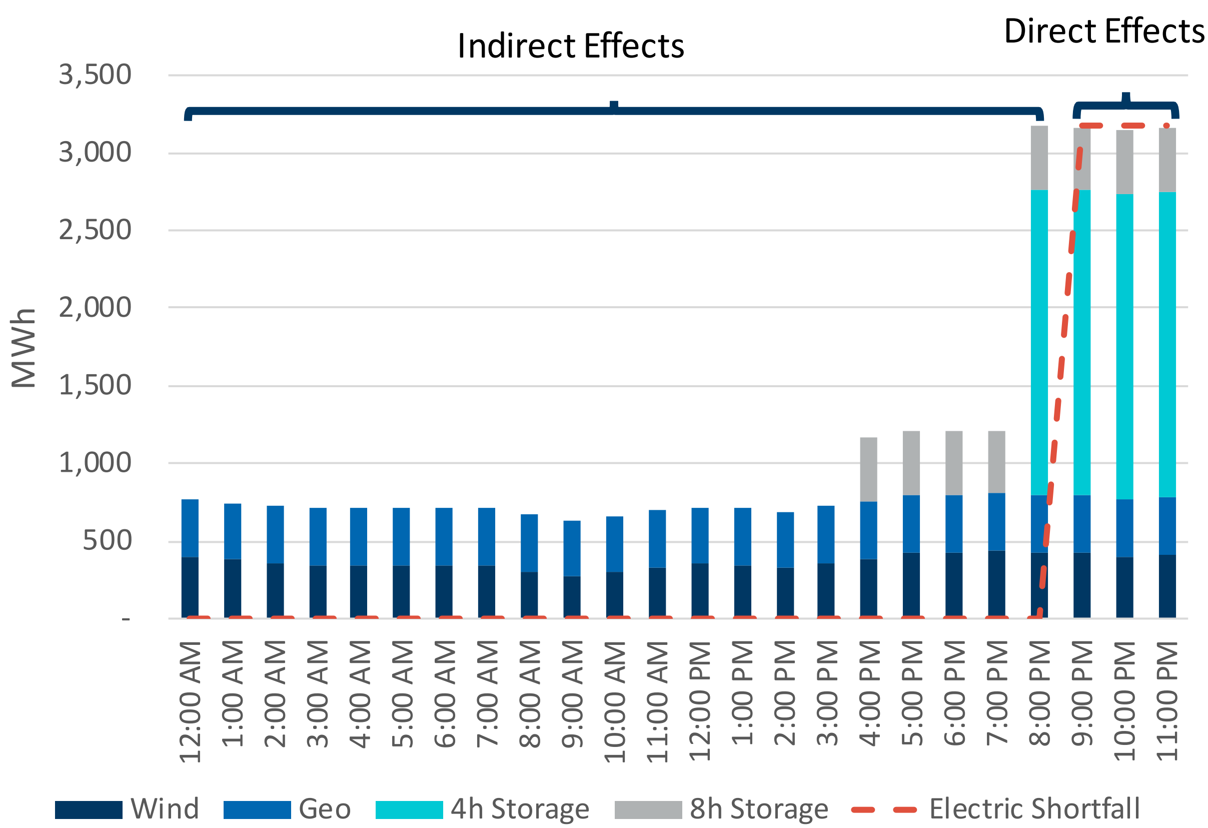
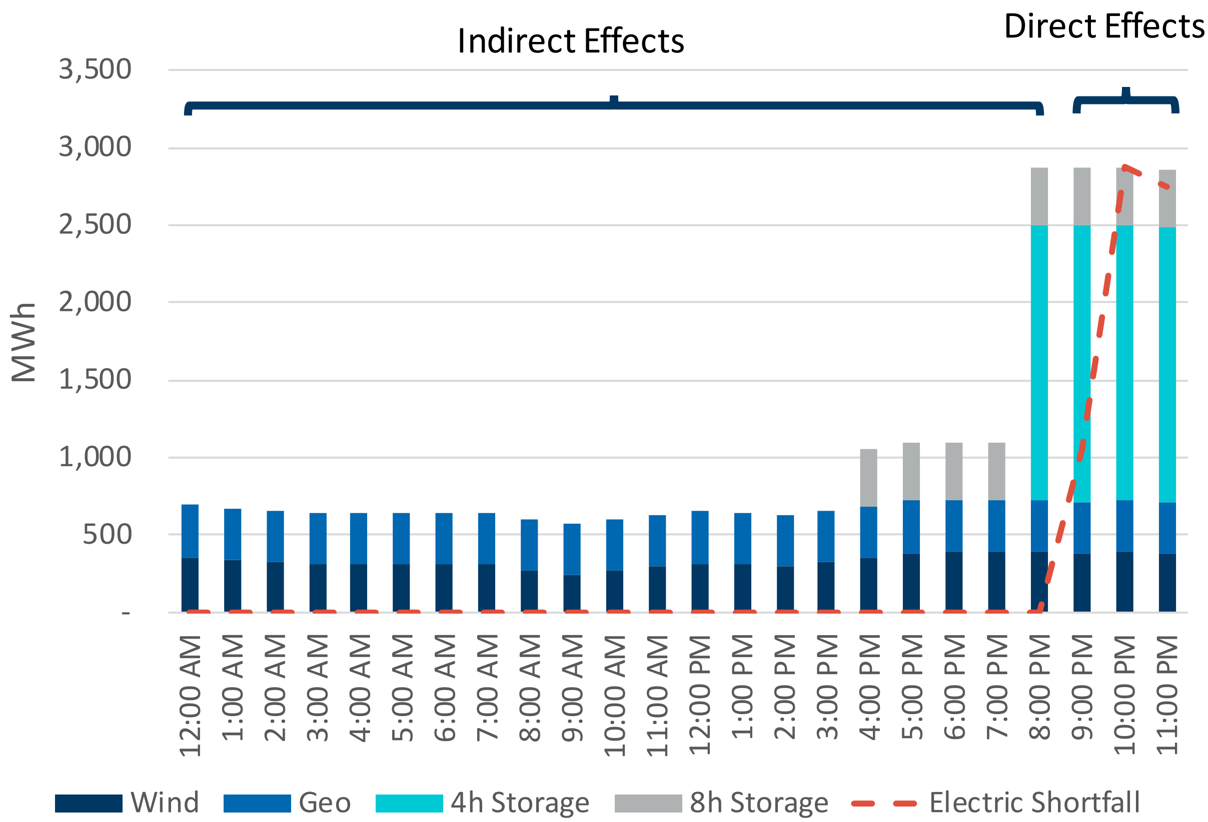


Figure 17 has two important annotations. The "Direct Effects" show the contribution of the generation portfolio to meeting the previously defined electric shortfall directly. However, once brought online, the generating resources contribute carbon-free energy to California's grid year-round. The "Indirect Effects" show generation from the resources outside of the electric shortfall hours. This generation will bid into the market at a lower price than higher marginal cost generation, such as natural gas, due to the near-zero marginal cost of producing wind and geothermal energy. As such, it reduces gas burn during the less-critical hours of the peak day for the power system, freeing up more gas to be used either in the electric generation sector or another sector. This additional displacement of gas-fired generation outside of the critical hours makes the sizing of Portfolio 3 conservative, allowing for a margin of error for inherent uncertainty in load forecasts, renewable production, generator outages, etc.

Figure 18 below shows the generation planned from the 2035 generation additions.

Figure 18: Portfolio 3 Generation from 2035 Generator Additions



Key Inputs and Assumptions

The key inputs and assumptions for Portfolio 3 are shown below in Table 27.

Table 27: Portfolio 3 Key Inputs and Assumptions

Input	Discussion	Source
Generation Mix	Based on analysis of the 11.5 GW Procurement Order, excluding solar resources	11.5 GW Procurement Order; FTI and CPUC analysis
Wind Generation Profile	Average hourly regional wind generation profiles	NREL Wind Integration National Dataset Toolkit
Geothermal Capacity Factor	Average annual capacity factor assumed	NREL 2021 Annual Technology Baseline Workbook
Storage Discharge	Assumed maximum output during the most constrained electric system hours	FTI assumption
Wind, Geothermal, and 4h Storage cost characteristics	Capital Cost, Fixed O&M, Variable O&M	NREL 2021 Annual Technology Baseline Workbook
Pumped Storage cost characteristics	Capital Cost, Fixed O&M, Variable O&M	Pacific Northwest National Laboratory 2020 Grid Energy Storage Technology Cost and Performance Assessment report

Modeling Results

FTI added the 2027 and 2035 generator additions to the respective years of their PLEXOS model to verify the solution for the 1 in 10 Winter Peak Day from both a power system and gas system perspective. Three winter peak days were run in sequence for both model years. It was found that all electrical load was served in both model years, while burning no more gas than the maximum amounts identified as being available by the hydraulic gas system modeling.

Cost-Benefit Analysis

In the Portfolio 3 solution, the levelized annual costs of $653 million in 2027 and $597 million in 2035 are comprised of the estimated costs of constructing and operating the additional generator and storage resources. The inputs into the levelized cost calculation are displayed below in Table 28 and Table 29.

Table 28: Portfolio 3 – 2027 Cost and Performance Characteristics

Technology	Capacity (MW)	Capital Cost ($/kW)	Fixed O&M ($/kW-y)	Variable O&M ($/MWh)	Capacity Factor
Wind	1,497	$1,083	$40.1	$0.00	35.0%
Geothermal	460	$5,833	$130.4	$0.00	90.0%
4h Battery Storage	1,968	$1,092	$27.3	$0.00	Endogenous
Pumped Storage (10h duration)[77]	409	$4,364	$78.3	$0.00	Endogenous

Table 29: Portfolio 3 – 2035 Cost and Performance Characteristics

Technology	Capacity (MW)	Capital Cost ($/kW)	Fixed O&M ($/kW-y)	Variable O&M ($/MWh)	Capacity Factor
Wind	1,355	$903	$37.5	$0.00	35.0%
Geothermal	416	$5,413	$127.6	$0.00	90.0%
4h Battery Storage	1,781	$981	$24.5	$0.00	Endogenous
Pumped Storage (10h duration)	370	$4,364	$79.4	$0.00	Endogenous

Wind, geothermal, and battery storage (4-hr) cost data are from the National Renewable Energy Laboratory 2021 Annual Technology Baseline Workbook. Pumped storage cost data is from the Pacific Northwest National Laboratory 2020 Grid Energy Storage Technology Cost and Performance Assessment report. Wind and geothermal capacity factor assumptions are from the National Renewable Energy Laboratory Wind Integration National Dataset Toolkit and National Renewable Energy Laboratory 2021 Annual Technology Baseline Workbook, respectively.

[77] The mid-term reliability 11.5 GW NQC procurement order defines long-duration storage as "providing 8 hours of storage or more." The source for the pumped storage costs examines storage with 10-hour duration, which meets the requirement for long-duration storage given in the order.

A breakdown of the Portfolio 3 investment costs by retirement year and the Portfolio 3 cost benefit summary are provided below in Table 30 and Table 31, respectively. Portfolio 2 cost-benefit analysis is further detailed in "Appendix III: Detailed Financial Modeling Results."

Table 30: Portfolio 3 Levelized Annual Investment Costs (2019$)

	2027	2035
Total Investment Costs	**$652,956,000**	**$596,740,000**
Wind	$104,014,000	$128,451,000
Geothermal	$213,330,000	$181,757,000
Energy Storage - 4 hr	$190,245,000	$154,606,000
Pumped Storage - 10 hr	$145,367,000	$131,926,000

Table 31: Portfolio 3 Cost-Benefit Analysis (2019$)

	2027	2035
Total Annual Cost	**$652,956,000**	**$596,740,000**
Total Investment Cost	$652,956,000	$596,740,000
Electricity Cost Increase	$0	$0
CA CO_2 Emissions Increase - Electricity	$0	$0
Gas Cost Increase	$0	$0
CA CO_2 Emissions Increase - Gas	$0	$0
Total Annual Benefits	**$712,630,000**	**$895,149,000**
Electricity Cost Reduction	$385,577,000	$579,110,000
CA CO_2 Emissions Reduction - Electricity	$71,715,000	$70,968,000
Gas Cost Reduction	$75,390,000	$82,230,000
CA CO_2 Emissions Reduction - Gas	$0	$0
Resource Adequacy Increase	$179,948,000	$162,841,000
Total Net Benefit	**$59,674,000**	**$298,409,000**
Benefit-Cost Ratio	**1.09**	**1.50**

The levelized annual investment costs are offset in both 2027 and 2035 by the benefits resulting from the addition of the generation resources.[78] Annual benefits accrue from:

1. Reductions in gas costs to Californians resulting from lower gas demand and subsequently lower gas prices ($75 million in 2027 and $82 million in 2035)
2. Electricity cost reductions driven by the addition of the near-zero marginal cost generation provided by wind and geothermal and by increased storage assets ($386 million in 2027 and $579 million in 2035)
3. Resource adequacy benefits provided by the additional generation and storage assets ($180 million in 2027 and $163 million in 2035), and
4. Reductions in CO_2 emissions resulting primarily from the addition of carbon-free generation ($72 million in 2027 and $71 million in 2035)

[78] While the modeling in PLEXOS confirmed that existing transmission capacity between zonal regions is sufficient for this portfolio solution, it should be noted that system upgrades within the zones could be necessary to facilitate the additional generation. This could lead to increased costs for this portfolio.

D. Portfolio #4: Transmission Additions

Introduction

Portfolio 4 analyzes whether allowing for increased imports of out-of-state power into California can be an effective solution to the Shortfall identified in the Base Case. The design of Portfolio 4 reflects two important considerations:

- In-state vs. Out-of-state Transmission Additions: In California, planning for new resources through the Integrated Resource Plan ("IRP") process and for in-state transmission additions is linked to the CAISO's annual TPP process. The IRP process identifies required new resources and provides guidance on the level, timing, mix and location of these resources. In its annual TPP, the CAISO uses guidance from the IRP process on the level, timing, mix and location of new resources and plans for in-state transmission additions or reinforcements. The solution proposed in Portfolio 4 is distinct in that it is built around the concept of using transmission projects that bring out-of-state power into California as a means of dealing with the Shortfall. That is, new builds in California and the delivery of such resources are maintained at Base Case levels and changes are made to transmission of resources from out-of-state. Two features of this concept are noteworthy:
    - The concept does not assume the import of power from specific out-of-state generation projects dedicated to serving California for the 1 in 10 Winter Peak Day. Rather, the concept envisions that with an increase in out-of-state transmission capacity, existing or already-planned resources outside California (which are modeled in the WECC-wide model used in this study) will be dispatched to meet the 1 in 10 Winter Peak Day Shortfall. While these out-of-California resources exist in the modeled Base Case, the CAISO interface limit restricts the ability to deliver such resources.
    - It is unlikely that a generation project would be built solely to meet the needs of a 1 in 10 Winter Peak Day. Similarly, making an interstate transmission addition solely to deal with a 1 in 10 Winter Peak Day is not likely to be cost-effective. It is likely — and consistent with the history of transmission projects — that they will be built with the expectation of multiple benefits. Thus, a Portfolio 4 transmission addition to import more power into California would offer benefits in the form of potentially lowering annual production costs, as well as providing RA resources to California. It may increase or decrease GHG emissions, depending on the generation dispatched. Such benefits (and costs) are included in the benefit-cost assessment of Portfolio 4. The transmission project would also deal with the Shortfall from an Aliso Canyon shutdown.
- The inherent complexities of siting, permitting, and bringing on-line transmission projects is well-documented. In fact, major transmission projects have taken 10 years or more from initial proposal to completion. Therefore, it was determined that a Portfolio 4 solution would not be

feasible for the 2027 timeframe. Accordingly, it is considered only as a 2035 solution in this study.

Modeling Framework

The modeling framework used here is a WECC-wide PLEXOS model with inter-zonal transmission limits, as discussed earlier under the Base Case and Portfolio 3. The Base Case representation of transmission-related limits in the WECC-wide system in PLEXOS is consistent with the 2019-2020 IRP and includes:

- Specific BA to BA transmission limits, based on the SERVM inputs in the IRP modeling
- A CAISO interface limit of 11,600 MW for the total transmission from outside CAISO into CAISO for all hours of the year (also referred to as CAISO Maximum Import Capability)[79]

In the Base Case modeling, the electric generator gas burn in 2035 would be 682 MMCFD (on a 24-hour basis on the 1 in 10 Winter Peak Day) if there were no constraints on gas supply (i.e., Aliso Canyon is available). However, if Aliso Canyon were unavailable, the results from the hydraulic modeling show that the gas system could only serve a maximum of 359 MMCFD of electric generator demand and remain operationally reliable. As concluded in the Base Case modeling, this leads to a Gas Shortfall in 2035 of 323 MMCFD (682 MMCFD minus 359 MMCFD, on a 24-hour basis on the 1 in 10 Winter Peak Day) or and Electric Shortfall of 2,875 MW for the critical hour.

The Base Case modeling also showed that on a 1 in 10 Winter Peak Day with no constraints on gas, the CAISO interface was at its limit of 11,600 MW during the critical hour of 2035. These Base Case results provide the basis for formulating Portfolios 4a and 4b. That is, the Electric Shortfall could be addressed by relaxing the CAISO interface limit to allow more electricity imports.

CAISO's footprint covers approximately 80 percent of California load, and the CAISO and non-CAISO parts of the power system are part of an interconnected WECC. Because of this interconnectedness, transmission additions from out-of-California into CAISO or to other non-CAISO parts of the state are likely to affect the interface limit.

Transmission additions could include new high voltage transmission lines as well as other reinforcements to relieve limiting factors. Quantifying the impact of transmission additions on the interface limit into CAISO and the interzonal transmission limits requires power flow modeling, and CAISO has confirmed that such a study requires a multi-year path rating process to establish a revised interface limit and valid changes to interzonal limits. Therefore, from the standpoint of this study, it is not feasible or meaningful to identify specific transmission additions and represent them in the model as a change to the CAISO interface limit and/or interzonal transmission limits.

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[79] CPUC Energy Division, *2019-20 IRP: Proposed Reference System Portfolio Validation with SERVM Reliability and Production Cost Modeling*, November 6, 2019

Instead, this study formulates "what if" changes to the transmission limits and examines their ability to deal with the Electric Shortfall. Two solutions were identified for this study and are discussed below:

- Portfolios 4a: Under Portfolio 4a, the CAISO interface limit of 11,600 MW is increased by exactly the Base Case 2035 Electric Shortfall of 2,875 MW, while maintaining the daily limit of 359 MMCFD for the gas burn in affected gas plants, which is the maximum the gas system can support without Aliso Canyon. Put another way, this portfolio tests, in a "what if" sense, whether the Shortfall from the unavailability of Aliso Canyon can be addressed by increasing the CAISO interface limit by exactly 2,875 MW.
- Portfolio 4b: Portfolio 4b tests whether a smaller combination of CAISO interface limit relaxation and additional transmission into the non-CAISO part of the state would alleviate the Electric Shortfall. Specifically, under Portfolio 4b the increase in transmission is made up of an increase in the (i) CAISO interface limit of 1,000 MW, and (ii) an increase in the Arizona to LADWP (which is not in the CAISO footprint) interzonal limit of 1,000 MW. As in Portfolio 4a, a daily limit of 359 MMCFD is set for the gas burn in the affected gas plants.

  Several points regarding Portfolio 4b are worth noting:

  - The inputs for Portfolio 4b are for illustrative purposes and not intended to assert that this combination (or an alternative one) is technically achievable. Under this illustrative case, an increase in transmission into the non-CAISO portion (i.e., Arizona to LADWP) is *assumed* to allow imports to displace gas generation in the non-CAISO portions without being subject to the broader CAISO interface limit that applies to all imports into CAISO. This assumption must be technically validated because a transmission addition in one location could create limiting conditions elsewhere in the interconnected system, and confirmation of the technical validity of any given combination requires a power flow study and analyses of path ratings which, as noted, is a multi-year process. Because the technical validity of this (or an alternative) combination cannot be verified without a power flow study, no combinations other than this illustrative one was examined.
  - While the above caveat about not being able to verify the technical validity of a combination is important, one finding of this illustrative example is that combining an increase in the CAISO interface limit with an increase in the interzonal limit into a non-CAISO part of the state *could* potentially allow for the Shortfall to be met with less than a 2,875 MW increase in transmission.

The transmission additions to implement either Portfolio 4a or 4b do not necessarily have to be based on adding large new transmission lines. Select reinforcements in locations that currently limit transmission and the addition of small lines to debottleneck key points of congestion may allow either Portfolio 4a or 4b to be implemented. Increasing the CAISO interface limit, which is the Portfolio 4a solution and the Portfolio 4b solution, is likely to offer multiple engineering options for implementation because targeted reinforcements in different parts of the large WECC footprint can contribute to increasing the interface limit.

Key Inputs and Assumptions

Portfolios 4a and 4b were analyzed by changing PLEXOS inputs for transmission limits and gas burn limits, as set forth below in Table 32.

Table 32: Key Inputs for Portfolios 4a and 4b

Inputs	Portfolio 4a	Portfolio 4b
CAISO Interface Limit	Increased by 2,875 MW	Increased by 1,000 MW
Interzonal Transmission Limits	No change	Arizona to LADWP limit increased by 1,000 MW
Daily Gas Burn Limit	359 MMCFD	359 MMCFD

Modeling Results

The modeling results showed that both Portfolios 4a and 4b can address the Gas Shortfall, assuming an increase in the CAISO interface limit.

The Portfolios 4a and 4b modeling produced the following key findings for the 1 in 10 Winter Peak Day:

- Between midnight and 9 AM, 2 PM, 3 PM, and after the critical, binding hour of 10 PM shown previously in Figure 8 and Figure 9, California imports more power under Portfolios 4a and 4b, thus alleviating the Gas Shortfall over a 24-hour period.
- At 11 PM and midnight for Portfolio 4a and from 10 PM to midnight for Portfolio 4b, California imports electricity up to the CAISO interface limit.
- The higher transmission limits increase gas-fired generation outside California, which is then transmitted into California to alleviate the shortfall.[80]

Figure 19 and Figure 20 below show CAISO interface imports are used at higher levels under Portfolio 4a and 4b than the Base Case during early morning hours and considerably more between 10 pm and midnight. This indicates the increased transmission capacity in these portfolios would allow least cost generator dispatch to address the Electric Shortfall under the gas burn constraint.

[80] Note that the modeling of Portfolios 4a and 4b focus on the gas burn on the 1 in 10 Winter Peak Day when Aliso Canyon is not available. The study also models the system on an annual basis for purposes of estimating total gas burn and associated emissions. This annual modeling accounts properly for the emission impacts of California electricity imports.

Figure 19: Portfolio 4a – CAISO Interface Imports by Hour on 1 in 10 Winter Peak Day in 2035

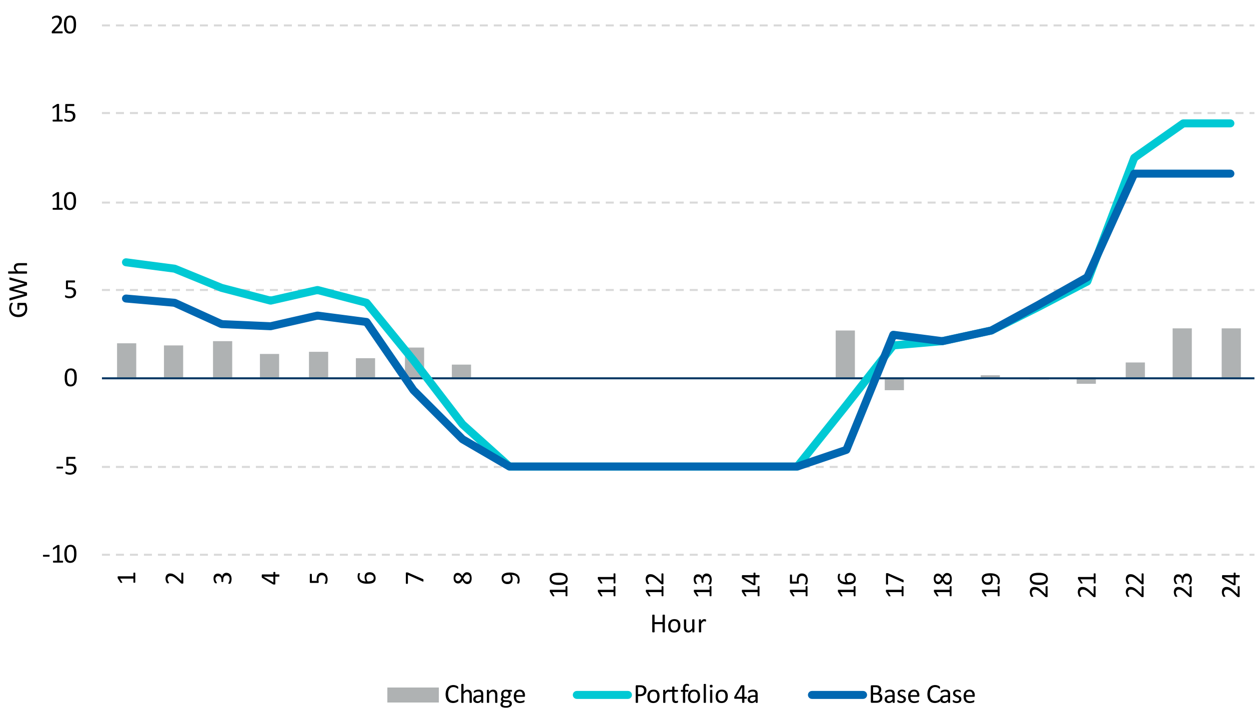


Figure 20: Portfolio 4b – CAISO Interface Imports by Hour on 1 in 10 Winter Peak Day in 2035

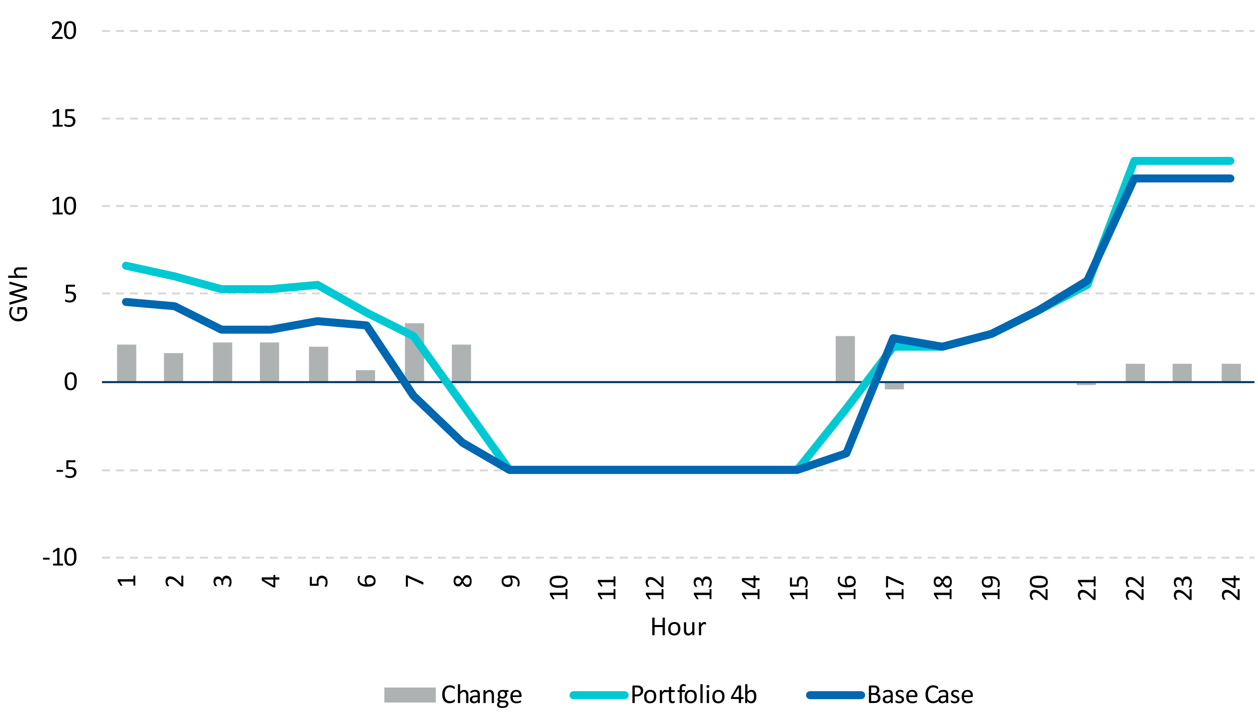


Figure 21 and Figure 22 below show the same results but from a gas demand perspective. The hourly gas demand on the 1 in 10 Winter Peak Day for both portfolios is markedly lower than the Base Case during the hours from midnight to 9 AM and from 10 PM to midnight the next day as SoCalGas-connected gas-fired electric generation is displaced by electricity imports.

Figure 21: Portfolio 4a – Electric Generation Gas Burn on the 1 in 10 Winter Peak Day in 2035 on the SoCalGas System

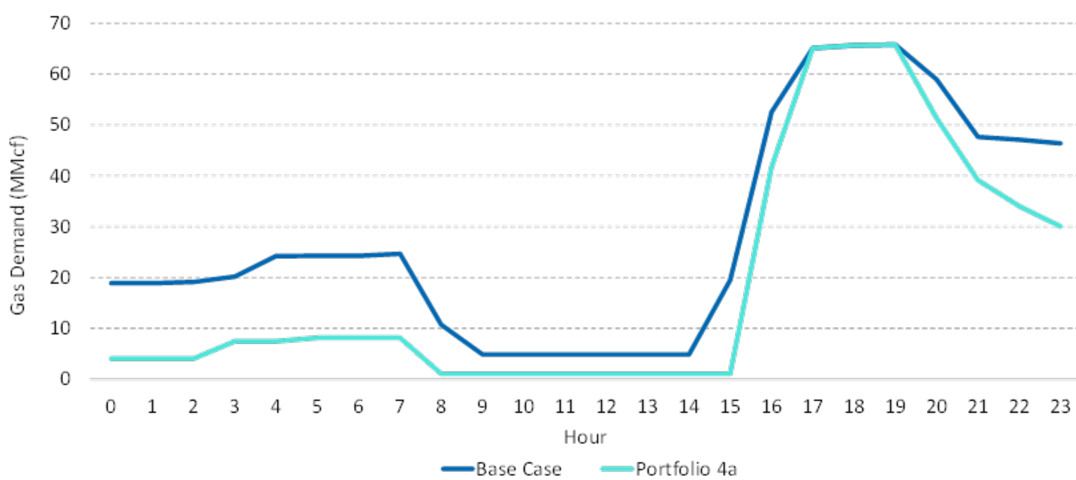


Figure 22: Portfolio 4a – Electric Generation Gas Burn on the 1 in 10 Winter Peak Day in 2035 on the SoCalGas System

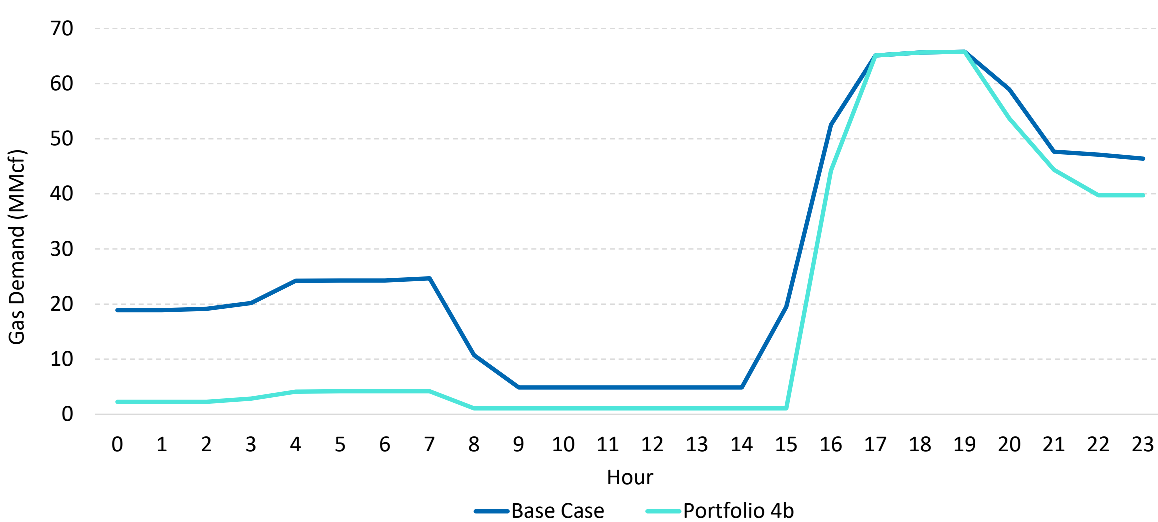
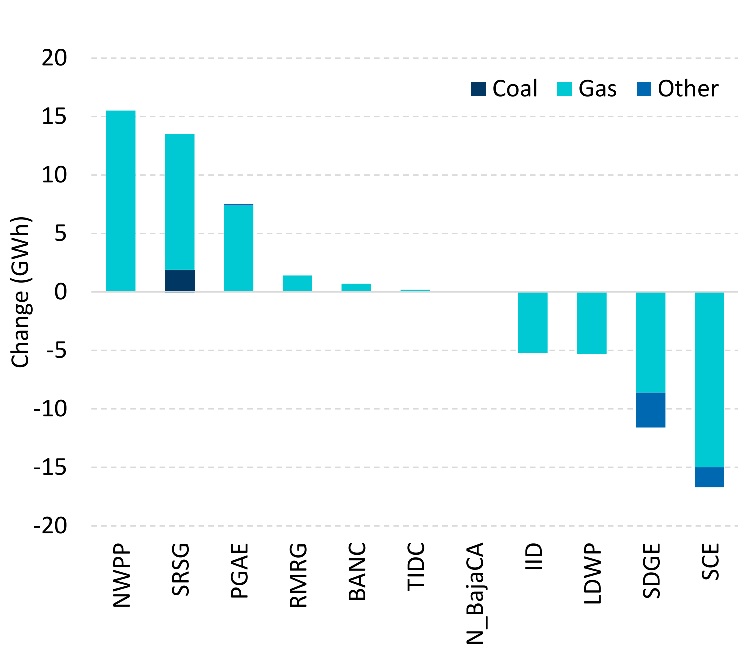


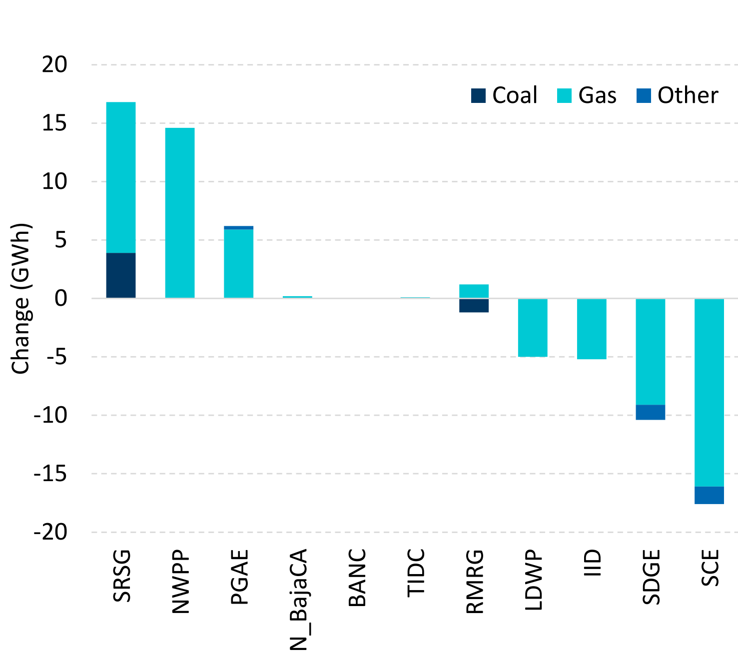
Figure 23 and Figure 24 show that under Portfolio 4a and 4b, the Shortfall is met predominantly by displacing gas generation in Southern California with increased gas generation in the rest of WECC, notably in the Northwest and the Southwest (Arizona, New Mexico, Southern Nevada). For WECC as a whole, Portfolio 4a leads to a 1.9 GWh increase in coal generation, a 2.8 GWh increase in gas generation, and a 4.7 GWh decrease in “other” generation. Portfolio 4b leads to a 2.7 GWh increase in coal generation, a 0.5 GWh decrease in gas generation, and a 2.5 GWh decrease in “other” generation.

Figure 23: Portfolio 4a – Change in WECC Dispatch from Base Case



Abbrev.	Name
SRSG	Southwest Reserve Sharing Group
NWPP	Northwest Power Pool
PGAE	Pacific Gas and Electric Company
N_BajaCA	North Baja California
BANC	Balancing Authority of Northern California
TIDC	Turlock Irrigation District
RMRG	Rocky Mountain Reserve Group
LDWP	Los Angeles Department of Water and Power
IID	Imperial Irrigation District
SDGE	San Diego Gas & Electric
SCE	Southern California Edison

Figure 24: Portfolio 4b – Change in WECC Dispatch from Base Case



Abbrev.	Name.
SRSG	Southwest Reserve Sharing Group
NWPP	Northwest Power Pool
PGAE	Pacific Gas and Electric Company
N_BajaCA	North Baja California
BANC	Balancing Authority of Northern California
TIDC	Turlock Irrigation District
RMRG	Rocky Mountain Reserve Group
LDWP	Los Angeles Department of Water and Power
IID	Imperial Irrigation District
SDGE	San Diego Gas & Electric
SCE	Southern California Edison

As previously noted, the ability of Portfolio 4b to achieve the 1,000 MW increase in the interzonal limit without creating other limiting conditions must be confirmed with a power flow study and a path rating process. Assuming that this combination is technically feasible, the modeling suggests that a total MW increase of less than 2,875 MW could potentially address the Electric Shortfall. This is because an increase in transmission into the non-CAISO portion (e.g., Arizona to LADWP) allows imports to displace gas generation in the non-CAISO portions without being subject to the broader interface limit that applies to all imports into CAISO.[81]

Cost-Benefit Analysis

Portfolio 4a

The Portfolio 4a solution is estimated to incur $125 million in annual costs in 2019 dollars if Aliso Canyon were closed in 2035, comprised solely of the estimated investment costs related to the development and operation of new transmission lines into and around California.

The annual benefits of Portfolio 4a outweigh the annual costs by a factor of 1.56. Benefits include a reduction in gas costs of $7 million, a reduction in electricity costs of $121 million, a resource adequacy benefit of $63 million, and a California CO_2 emissions reduction benefit of $4 million.

A breakdown of the Portfolio 4a cost benefit summary is provided below in Table 33. Portfolio 4a cost-benefit analysis is further detailed in "Appendix III: Detailed Financial Modeling Results."

[81] As noted, this would be valid only if an increase of transmission into the non-CAISO portion does not create new limiting conditions that affect the CAISO limit. Without a power flow study and revised path rating, this remains a "what if" assumption.

Table 33: Cost-Benefit Summary for Portfolio 4a (2019$'s)

	2035
Total Annual Cost	**$125,483,000**
Total Investment Cost	$125,483,000
Electricity Cost Increase	$0
CA CO_2 Emissions Increase - Electricity	$0
Gas Cost Increase	$0
CA CO_2 Emissions Increase - Gas	$0
Total Annual Benefits	**$195,303,000**
Electricity Cost Reduction	$120,633,000
CA CO_2 Emissions Reduction - Electricity	$4,071,000
Gas Cost Reduction	$7,464,000
CA CO_2 Emissions Reduction - Gas	$0
Resource Adequacy Increase	$63,135,000
Total Net Benefit	**$69,820,000**
Benefit-Cost Ratio	**1.56**

Portfolio 4b

The Portfolio 4b solution is estimated incur $90 million in annual costs in 2019 dollars if Aliso Canyon were retired by 2035, which is lower than Portfolio 4a because the total transmission size is lower (2,000 MW vs. 2,875 MW). As with Portfolio 4a, the Portfolio 4b annual costs are comprised solely of the estimated investment costs related to the development and operation of new transmission lines into and around California.

The annual benefits of Portfolio 4b outweigh the annual costs by a factor of 1.97. Benefits include a reduction in gas costs of $13 million, a reduction in electricity costs of $119 million, and a resource adequacy benefit of $44 million.

A breakdown of the Portfolio 4b cost benefit summary is provided below in Table 34. Portfolio 4b cost-benefit analysis is further detailed in "Appendix III: Detailed Financial Modeling Results."

Table 34: Cost-Benefit Summary for Portfolio 4b (2019$'s)

	2035
Total Annual Cost	**$89,588,000**
Total Investment Cost	$87,293,000
Electricity Cost Increase	$0
CA CO_2 Emissions Increase - Electricity	$2,295,000
Gas Cost Increase	$0
CA CO_2 Emissions Increase - Gas	$0
Total Annual Benefits	**$176,295,000**
Electricity Cost Reduction	$119,390,000
CA CO_2 Emissions Reduction - Electricity	$0
Gas Cost Reduction	$12,985,000
CA CO_2 Emissions Reduction - Gas	$0
Resource Adequacy Increase	$43,920,000
Total Net Benefit	**$86,707,000**
Benefit-Cost Ratio	**1.97**

E. Portfolio #5: Hybrid

Introduction

Portfolio 5 evaluated three scenarios in both 2027 and 2035 that incorporate elements of the other Portfolios previously detailed. Specifically, the 2027 Portfolio 5 solutions reflect a blend of Portfolio 2 and Portfolio 3 investments, while the 2035 solutions reflect a blend of Portfolio 2 and Portfolio 4a investments.[82]

The 2027 Portfolio 5 solutions reflect varying levels of Electrification and Electric Energy Efficiency, as evaluated in Portfolio 2, along with the addition of new generation resources, as evaluated in Portfolio 3. The amount of generator additions in each individual Portfolio was set at the amount necessary to

[82] Portfolio 4a was chosen over Portfolio 4b as the 2035 Basis Portfolio for Portfolio 5 solutions because it represents a more flexible solution from both a construction and operational perspective. The CAISO interface limit can potentially be increased through a variety of upgrades to existing infrastructure for which permitting and actual construction might be significantly easier than for a new high voltage, long distance, transmission line. Furthermore, once the CAISO interface limit is increased, the added import capability provides more optionality, as more power could be imported on different lines depending on different market conditions and different times of the day or year as opposed to a single high voltage transmission line that provides access to only one additional outside source of power supply.

meet the remaining Shortfall after accounting for the impacts of Electrification and Electric Energy Efficiency. The 2035 Portfolio solutions also reflect varying levels of Electrification and Electric Energy Efficiency, but instead rely on new transmission capacity to meet the remaining Shortfall after accounting for the impacts of Electrification and Electric Energy Efficiency.

Modeling Framework

Portfolio 5 solutions were modeled in the same manner as the underlying Portfolios on which they were based ("Basis Portfolios").

Key Inputs and Assumptions

The relative contributions of the Basis Portfolios to each of the Portfolio 5 solutions was designed to reflect varying levels of investment or certainty of achievement of Electrification and Electric Energy Efficiency considered in Portfolio 2, while filling the remainder of the Shortfall with a mix of investments that was commercially and operationally feasible with regards to the development of new infrastructure as was considered in Portfolio 3 and Portfolio 4.

To establish the relative contributions of each Basis Portfolio, the amount of Electrification and Electric Energy Efficiency considered in Portfolio 2 was reduced, as necessary, to levels that would necessitate additional investments in order to meet the Shortfall, as shown below in Table 35.[83]

Table 35: Portfolio 5 Percentages of Electrification & Electric Energy Efficiency Evaluated

Year	Portfolio 5 Scenario	Percentage of Portfolio 2
2027	5a	100%
2027	5b	50%
2027	5c	25%
2035	5d	40%
2035	5e	20%
2035	5f	10%

After accounting for the impacts of Electrification and Electric Energy Efficiency, which was evaluated using the same methodology as detailed in "Section V.B. Portfolio #2: Gas Demand Reduction," the

[83] In the 2027 Portfolio 2 solution, the Gas Shortfall was not met after accounting for 100% of projected Electrification and Electric Energy Efficiency impacts, with a remaining Gas Shortfall of 67 MMCFD. In Portfolio 5a, it is assumed that the remaining Gas Shortfall of 67 MMCFD is met with new generation resources, as opposed to Noncore Demand Response as was evaluated in the Portfolio 2 solution.

remaining Gas Shortfall in 2027 and 2035 was used to determine the required amount of new generation and transmission capacity, respectively, necessary to meet the remaining Shortfall. The amount of additional generation capacity required in each of the 2027 Portfolio 5 solutions is presented in Table 36, and the amount of additional transmission capacity required in each of the 2035 Portfolio solutions is presented in Table 37.

Table 36: 2027 Portfolio 5 Generation Capacity Required to Meet Shortfall

Year	Portfolio 5 Scenario	Required Generation Capacity (MW)
2027	5a	737
2027	5b	2,535
2027	5c	3,433

Table 37: 2035 Portfolio 5 Transmission Capacity Required to Meet Shortfall

Year	Portfolio 5 Scenario	Required Transmission Capacity (MW)
2035	5d	710
2035	5e	1,794
2035	5f	2,335

Modeling Results

The total 1 in 10 Winter Peak Day impacts, expressed in MMCFD, for each component of the Portfolio 5 solutions in 2027 and 2035 are presented below in Table 38 and Table 39, respectively.

Table 38: Portfolio 5 2027 Solutions 1 in 10 Winter Peak Day Impacts

	Portfolio 5a	Portfolio 5b	Portfolio 5c
Shortfall (MMCFD)	395	395	395
Increased Electric Generation Demand (MMCFD)	20	10	5
Decreased Gas Heating Demand (MMCFD)	(348)	(174)	(87)
Remaining Shortfall Met with Generation (MMCFD)	**67**	**231**	**313**

Table 39: Portfolio 5 2035 Solutions 1 in 10 Winter Peak Day Impacts

	Portfolio 5d	Portfolio 5e	Portfolio 5f
Shortfall (MMCFD)	323	323	323
Increased Electric Generation Demand (MMCFD)	20	11	5
Decreased Gas Heating Demand (MMCFD)	(265)	(133)	(66)
Remaining Shortfall Met with Transmission (MMCFD)	**78**	**201**	**262**

Cost-Benefit Analysis

In the 2027 Portfolio 5a solution, which evaluates the costs associated with Building Electrification and Electric Energy Efficiency at 100 percent of the Portfolio 2 amounts and incremental Generation Capacity of 737 MW, the levelized annual costs of $196 million are comprised of incremental costs related to Building Electrification, the development of new electric generation facilities, and an increase in electricity costs based on PLEXOS production cost modeling. The levelized annual benefits of $283 million are comprised of incremental Resource Adequacy benefits pertaining to new electric generation facilities along with decreases in gas costs, gas sector CO_2 emissions, electric sector CO_2 emissions based on PLEXOS production cost modeling.

In the 2027 Portfolio 5b solution, which evaluates the costs associated with Building Electrification and Electric Energy Efficiency at 50 percent of the Portfolio 2 amounts and incremental Generation Capacity of 2,535 MW, the levelized annual costs of $375 million are comprised of incremental costs related to Building Electrification and the development of new electric generation facilities. The levelized annual benefits of $436 million are comprised of incremental Resource Adequacy benefits pertaining to new electric generation facilities along with decreases in electricity costs, gas costs, gas sector CO_2 emissions, and electric sector CO_2 emissions based on PLEXOS production cost modeling.

In the 2027 Portfolio 5c solution, which evaluates the costs associated with Building Electrification and Electric Energy Efficiency at 25 percent of the Portfolio 2 amounts and incremental Generation Capacity of 3,433 MW, the levelized annual costs of $514 million are comprised of incremental costs related to Building Electrification and the development of new electric generation facilities. The levelized annual benefits of $548 million are comprised of incremental Resource Adequacy benefits pertaining to new electric generation facilities along with decreases in electricity costs, gas costs, gas sector CO_2 emissions, and electric sector CO_2 emissions based on PLEXOS production cost modeling.

The costs and benefits pertaining to each 2027 Portfolio 5 solution are presented in Table 40 below and discussed in more detail in "Appendix III: Detailed Financial Modeling Results."

Table 40: Cost Benefit Summary for 2027 Portfolio 5 Solutions

	Portfolio 5a	Portfolio 5b	Portfolio 5c
Total Annual Cost	**$196,312,000**	**$375,499,000**	**$513,902,000**
Total Investment Cost	$98,044,000	$375,499,000	$513,902,000
Electricity Cost Increase	$98,268,000	$0	$0
CA CO_2 Emissions Increase - Electricity	$0	$0	$0
Gas Cost Increase	$0	$0	$0
CA CO_2 Emissions Increase - Gas	$0	$0	$0
Total Annual Benefits	**$283,077,000**	**$435,845,000**	**$548,324,000**
Electricity Cost Reduction	$0	$141,728,000	$248,636,000
CA CO_2 Emissions Reduction - Electricity	$2,205,000	$37,099,000	$55,752,000
Gas Cost Reduction	$131,462,000	$92,339,000	$71,712,000
CA CO_2 Emissions Reduction - Gas	$118,819,000	$59,410,000	$29,705,000
Resource Adequacy Increase	$30,591,000	$105,269,000	$142,519,000
Total Net Benefit	**$86,765,000**	**$60,346,000**	**$34,422,000**
Benefit-Cost Ratio	**1.44**	**1.16**	**1.07**

In the 2035 Portfolio 5d solution, which evaluates the costs associated with Building Electrification and Electric Energy Efficiency at 40 percent of the Portfolio 2 amounts and incremental Transmission Capacity of 710 MW, the levelized annual costs of $239 million are comprised of incremental costs related to Building Electrification, the development of new electric transmission infrastructure, and an increase in both electricity costs and electric sector CO_2 emissions based on PLEXOS production cost modeling. The levelized annual benefits of $65 million are comprised of incremental Resource Adequacy benefits pertaining to new transmission infrastructure along with decreases in gas costs and gas sector CO_2 emissions based on PLEXOS production cost modeling.

In the 2035 Portfolio 5e solution, which evaluates the costs associated with Building Electrification and Electric Energy Efficiency at 100 percent of the Portfolio 2 amounts and incremental Transmission Capacity of 1,794 MW, the levelized annual costs of $122 million are comprised of incremental costs related to Building Electrification, the development of new electric transmission infrastructure, and an increase in both electricity costs and electric sector CO_2 emissions based on PLEXOS production cost modeling. The levelized annual benefits of $84 million are comprised of incremental Resource Adequacy benefits pertaining to new transmission infrastructure along with decreases in gas costs and gas sector CO_2 emissions based on PLEXOS production cost modeling.

In the 2035 Portfolio 5f solution, which evaluates the costs associated with Building Electrification and Electric Energy Efficiency at 10 percent of the Portfolio 2 amounts and incremental Transmission Capacity of 2,335 MW, the levelized annual costs of $100 million are comprised of incremental costs related to Building Electrification and the development of new electric transmission infrastructure. The levelized annual benefits of $126 million are comprised of incremental Resource Adequacy benefits pertaining to new transmission infrastructure along with decreases in both electric and gas costs and electric and gas sector CO_2 emissions based on PLEXOS production cost modeling.

The costs and benefits pertaining to each 2035 Portfolio 5 solution are presented in Table 41 below and discussed in more detail in “Appendix III: Detailed Financial Modeling Results.”

Table 41: Cost Benefit Summary for 2035 Portfolio 5 Solutions

	Portfolio 5d	Portfolio 5e	Portfolio 5f
Total Annual Cost	**$239,145,000**	**$122,017,000**	**$99,548,000**
Total Investment Cost	$21,617,000	$73,613,000	$99,548,000
Electricity Cost Increase	$204,308,000	$45,436,000	$0
CA CO_2 Emissions Increase - Electricity	$13,220,000	$2,968,000	$0
Gas Cost Increase	$0	$0	$0
CA CO_2 Emissions Increase - Gas	$0	$0	$0
Total Annual Benefits	**$65,337,000**	**$83,524,000**	**$126,332,000**
Electricity Cost Reduction	$0	$0	$48,524,000
CA CO_2 Emissions Reduction - Electricity	$0	$0	$917,000
Gas Cost Reduction	$8,276,000	$23,394,000	$15,258,000
CA CO_2 Emissions Reduction - Gas	$41,467,000	$20,734,000	$10,367,000
Resource Adequacy Increase	$15,594,000	$39,396,000	$51,266,000
Total Net Benefit	**($173,808,000)**	**($38,493,000)**	**$26,784,000**
Benefit-Cost Ratio	**0.27**	**0.68**	**1.27**

VI. Key Findings

A. Portfolio 1

Portfolio 1 evaluates the addition of new pipeline loops that would provide a direct offset to gas supply that would otherwise be sourced from Aliso Canyon. In both 2027 and 2035, it is assumed that these solutions provide no incremental market benefits in the form of electricity cost, gas cost, or emissions reductions as there would be no significant changes to the amounts or relative composition of gas and electricity consumed.

The Portfolio 1a solution represents the lowest total investment costs in both 2027 and 2035, with total costs (2019$) of $100 million in 2027 and $67 million in 2035. The implementation of the Portfolio 1 solutions could potentially provide more certainty than the other Portfolios considered in terms of projected costs, construction timelines, and confidence in the ability to meet the Shortfall that would arise should Aliso Canyon be retired.

B. Portfolio 2

Portfolio 2 evaluates growth in Building Electrification and Electric Energy Efficiency measures that result in gas demand reductions pertaining to reduced heating load. In the 2027 Portfolio 2 solution, the impacts of Building Electrification and Electric Energy Efficiency do not fully meet the Shortfall and the solution requires additional demand reduction, evaluated for this study in the form of potential Noncore Demand Response.

In 2027, the amount of Noncore Demand Response that would be required to meet the Shortfall is approximately 67 MMCFD, or 10 percent of projected Noncore demand on a 1 in 10 Winter Peak Day. In 2035, the impacts of Building Electrification and Electric Energy Efficiency provide a higher amount of gas demand reduction that exceeds the amount necessary to meet the Shortfall due to the higher level of progress in meeting electrification targets, and the solution does not require any Noncore Demand Response.

Production cost modeling results suggest that in 2027, the Portfolio 2 solution offers the second highest benefit to cost ratio as well as the second highest overall reduction in CO_2 emissions. In 2035, the Portfolio 2 solution represents the highest costs and second lowest benefit to cost ratio, but still the second highest overall reduction in CO_2 emissions.

A significant benefit of the Portfolio 2 solution is that it does not require the addition of new electric or gas physical infrastructure, which involve project risks such as those related to siting and permitting, cost overruns, etc. Additionally, program structures pertaining to Electrification, Energy Efficiency, and Demand Response can be evaluated and adjusted at regular intervals over time as conditions change, potentially providing a greater level of long-term flexibility than the other Portfolio solutions considered. However, this Portfolio’s success is also dependent on developments that are not directly under CPUC's control, such as modifications to California's building codes and standards and changes in customer behavior.

C. Portfolio 3

Portfolio 3 evaluates the addition of new electric generation and storage resources in the state of California as the sole investment strategy for meeting the Shortfall in both 2027 and 2035. The relative mix of new resources considered was based on the current and expected generation fleet for California, as described in "Section V.C. Portfolio #3: Generator Additions." In 2027, 4,334 MW of new generation capacity is required to meet the Shortfall, while in 2035, 3,992 MW of new generation capacity is required.

In 2027, the Portfolio 3 solution represents the solution with the highest total costs and lowest total reduction in CO_2 emissions, other than the Portfolio 1 solutions which assume no emissions reductions. However, the Portfolio 3 solution also boasts the highest total benefits in 2027. In 2035, the Portfolio 3 solution represents the solution with the second highest costs but also the highest total benefits and reduction in CO_2 emissions.

In both 2027 and 2035, the Portfolio 3 solution benefits are driven primarily by reductions in both electricity and gas costs as determined through production cost modeling. In 2027, the combined electricity and gas cost savings of $461 million represent approximately 71 percent of the $653 million in total investment costs. In 2035, the combined electricity and gas cost savings of $661 million more than offset the total investment costs of $597 million.

D. Portfolio 4

Portfolio 4a and 4b evaluate the addition of new electric transmission infrastructure allowing for the import of incremental electricity into California in order to meet the Shortfall in 2035. Due to the long-expected lead times for the construction of new transmission infrastructure, the Portfolio 4 solutions were not assumed to be viable for 2027.

Portfolio 4a and 4b represent the solutions with the lowest costs and highest benefit to cost ratio out of all the non-gas infrastructure solutions for 2035, however they also represent the solutions with the lowest amount of CO_2 reductions.

As noted above in the Key Findings for Portfolio 2, the development of new electric transmission infrastructure necessarily involves a certain level of risk due to siting, permitting, and cost overruns. Since the actual transmission infrastructure needed to implement this portfolio may differ from the portfolio solutions considered, the cost estimates applied are therefore less precise than those applied in other portfolios.

E. Portfolio 5

The Portfolio 5 solutions reflect varying contribution levels of demand side components from Portfolio 2 (i.e., Building Electrification and Electric Energy Efficiency) and supply side components from Portfolio 3 and Portfolio 4. To meet the Shortfall in 2027, incremental generation resources from Portfolio 3 are modeled. To meet the Shortfall in 2035, incremental transmission resources from Portfolio 4 are modeled. Generation and transmission were chosen as the 2027 and 2035 components, respectively, for the Portfolio 5 solutions because they exhibited the highest cost benefit ratios in each year.

The Portfolio 5 solutions incorporate levels of Electrification and Electric Energy Efficiency that are less than half of those considered in the Portfolio 2 solution and may represent a level more likely to be achieved.

For 2027, the Portfolio 2 solution represents lower total costs relative to the other Portfolios, but also lower total benefits, while the Portfolio 3 solution represents both the highest total costs and highest total benefits. The Portfolio 5a solution, which incorporates the same Portfolio 2 assumptions regarding the level of Electrification and Electric Energy Efficiency but meets the Shortfall with generation as opposed to Noncore Demand Response, results in nearly identical total costs as Portfolio 2, but higher benefits due to higher electricity cost savings and emissions reductions arising from the addition of new generation resources, as opposed to Noncore Demand Response which provides no market benefits.

For 2035, the Portfolio 2 solution represents the highest total cost solution but has benefits that are comparable to those of the Portfolio 4 solutions, primarily due to the greater impact on achieving a higher level of reduction in CO_2 emissions in Portfolio 2.

The Portfolio 5f solution results in more significant CO_2 emissions reductions than the Portfolio 4 solutions due to the inclusion of incremental increases in Electrification and Electric Energy Efficiency, while still resulting in a benefit to cost ratio over 1.0 due to significant electric and gas cost savings, which account for approximately half of the total Portfolio 5f benefits of $126 million.

F. Rate Impact Analysis

Each Portfolio solution was assessed in terms in investment costs and market benefits specific to gas and electric market activity. For the purposes of this study, it was assumed that all gas investment costs and market benefits are ultimately passed down to gas end-use customers while all electric investment costs and market benefits are ultimately passed down to electric end-use customers. While a full rate impact analysis was beyond the scope of this study, a review of costs and benefits broken down separately into gas market and electric market impacts provides insight into the relative impacts of each Portfolio solution specific to each market's rate base.[84]

For the Portfolio 1 Solutions, it is assumed new gas infrastructure costs are fully borne by gas customers and there are no market benefits. The remaining Portfolios, however, involve costs that are primarily borne by electric customers and there are market benefits. Modeling results suggest that in almost all cases, gas customers would realize a benefit related to lower gas prices, and the net benefit to gas customers would exceed that of the net benefit to electric customers. Portfolio 4b in 2035 was the only non-gas infrastructure portfolio evaluated in which the net electric market benefit exceeded the net gas market benefit.

Comparisons of gas and electric market impacts in 2027 and 2035 are shown below in Table 42 and Table 43, respectively.

Table 42: 2027 Comparison of Net Financial Impacts by Market

Portfolio	Electricity Cost Impact	Electric Investment Costs	Electric Market Net Impact	Gas Cost Impact	Gas Investment Costs	Gas Market Net Impact
Portfolio 1a	$0	$0	**$0**	$0	$100,421,000	**$100,421,000**
Portfolio 1b	$0	$0	**$0**	$0	$147,282,000	**$147,282,000**
Portfolio 2	$182,084,000	($12,959,000)	**$169,125,000**	($128,491,000)	$17,097,000	**($111,394,000)**
Portfolio 3	($385,577,000)	$652,956,000	**$267,379,000**	($75,390,000)	$0	**($75,390,000)**
Portfolio 5a	$98,268,000	$196,312,000	**$294,580,000**	($131,462,000)	$0	**($131,462,000)**
Portfolio 5b	($141,728,000)	$375,499,000	**$233,771,000**	($92,339,000)	$0	**($92,339,000)**
Portfolio 5c	($248,636,000)	$513,901,000	**$265,265,000**	($71,712,000)	$0	**($71,712,000)**

[84] For the purposes of evaluating potential rate impacts by market segment, estimated costs and benefits related to changes in CO_2 Emissions are omitted.

Table 43: 2035 Comparison of Net Financial Impacts by Market

Portfolio	Electricity Cost Impact	Electric Investment Costs	Electric Market Net Impact	Gas Cost Impact	Gas Investment Costs	Gas Market Net Impact
Portfolio 1a	$0	$0	**$0**	$0	$66,783,000	**$66,783,000**
Portfolio 1b	$0	$0	**$0**	$0	$118,255,000	**$118,255,000**
Portfolio 2	$629,313,000	($23,442,000)	**$605,871,000**	($89,894,000)	$0	**($89,894,000)**
Portfolio 3	($579,110,000)	$596,740,000	**$17,630,000**	($82,230,000)	$0	**($82,230,000)**
Portfolio 4a	($120,633,000)	$125,483,000	**$4,850,000**	($7,464,000)	$0	**($7,464,000)**
Portfolio 4b	($119,390,000)	$87,293,000	**($32,097,000)**	($12,985,000)	$0	**($12,985,000)**
Portfolio 5d	$204,308,000	$21,617,000	**$225,925,000**	($8,276,000)	$0	**($8,276,000)**
Portfolio 5e	$45,436,000	$73,613,000	**$119,049,000**	($23,394,000)	$0	**($23,394,000)**
Portfolio 5f	($48,524,000)	$99,548,000	**$51,024,000**	($15,258,000)	$0	**($15,258,000)**

Abbreviations and Acronyms

2019-20 IRP/RSP – Integrated Resource Plan/Reference System Plan

2019 IEPR – 2019 Integrated Energy Policy Report

2021 CEC Report – 2021 California Building Decarbonization Assessment Final Report

2021 Guidehouse Study – 2021 Energy Efficiency Potential and Goals Study prepared by Guidehouse Inc. for the CPUC

ATB – Annual Technology Baseline

BA – Balancing Authority

Bcf – Billion Cubic Feet

C&I – Commercial and Industrial

CAISO – California ISO

CBA – Cost Benefit Analysis

CEC – California Energy Commission

CPI – Consumer Price Index

CPUC – California Public Utilities Commission

CRF – Capital Recovery Factor

DLC – Direct Load Control

Dth – Dekatherm

ED Staff – CPUC's Energy Division

EG – Electric Generation

EIA – US Energy Information Administration

ELCCs – Effective Load Carrying Capabilities

Electric Shortfall – MW Level

EOR – Enhanced Oil Recovery

FERC – Federal Energy Regulatory Commission

FTI – FTI Consulting, Inc.

Gas Shortfall – Unserved Gas Demand

GHG – Greenhouse Gas

GPCM – Gas Pipeline Competition Model

GSC – Gas Supply Consulting, Inc.

GW – Gigawatt

GWh – Gigawatt hour

HP – Compressor Horsepower

IEPR – Integrated Energy Policy Report

IRP – Integrated Resource Plan

ITC – Investment Tax Credit

LADWP – Los Angeles Department of Water and Power

LDC – Local Distribution Company

LNG – Liquefied Natural Gas

LOLE – Loss of Load Expectation

LOLP – Loss of Load Probability

MMBtu – Million British Thermal Unit

MMCFD – Million Cubic Feet per day

MMTCO2e – Million Metric Tons of CO_2 equivalent

MW - Megawatt

MWh – Megawatt hour

NGL – Natural Gas Liquids

NQC – Net Qualifying Capacity

NREL – National Renewable Technology Laboratory

PG&E – Pacific Gas and Electric

PTC – Production Tax Credit

RA – Resource Adequacy

RNG – Renewable Natural Gas

RPU – Receipt Point Utilization

SB – Senate Bill

SCC – Social Cost of Carbon

SCE – Southern California Edison

SDG&E – San Diego Gas and Electric

SERVM – Strategic Energy & Risk Valuation Model

SoCalGas – Southern California Gas Company

TPP – Transmission Planning Portfolio

TRC – Total Resource Cost

WECC – Western Electric Coordination Council

Appendix I: Detailed Power Market Modeling Inputs and Results

In the supplementary file "Detailed Power Market Modeling Input and Results.xlsx", PLEXOS modeling results are provided for each of the 14 cases listed in the table below.

Table 44: Case Summary by Year

	2027	2035
Base Case	X	X
Portfolio 2	X	X
Portfolio 3	X	X
Portfolio 4a		X
Portfolio 4b		X
Portfolio 5a	X	
Portfolio 5b	X	
Portfolio 5c	X	
Portfolio 5d		X
Portfolio 5e		X
Portfolio 5f		X

For each of the cases listed, the following worksheets are provided:

- **Generation:** These worksheets show unit-level generation in MW for each hour of the 1 in 10 Winter Peak Day.
- **Available Capacity:** These worksheets show unit-level capacity available to generate (not on maintenance or forced outage) in MW for each hour of the 1 in 10 Winter Peak Day.
- **Line Flows:** These worksheets show balancing authority to balancing authority transmission line flows in MW for each hour of the 1 in 10 Winter Peak Day.
- **Battery Activity:** These worksheets show unit-level battery generation and load in MW for each hour of the 1 in 10 Winter Peak Day.
- **Net Interchange:** These worksheets show balancing authority level net interchange in MW for each hour of the 1 in 10 Winter Peak Day.
- **Maintenance:** These worksheets show the total amount of generating capacity not available to generate due to maintenance in MW on the balancing authority level for each hour of the 1 in 10 Winter Peak Day. Maintenance events in PLEXOS are generated randomly based on probabilities assigned to generating technologies.
- **Forced Outage:** These worksheets show the total amount of generating capacity not available to generate due to forced outage in MW on the balancing authority level for each hour of the 1 in 10 Winter Peak Day. Forced outage events in PLEXOS are generated randomly based on probabilities assigned to generating technologies.
- **CO_2 Emissions:** These worksheets show the CO_2 emissions associated with California generation and electricity imports for the modeled year in metric tons.

- **Electricity Costs:** These worksheets show the calculated electricity costs for California balancing authorities for the modeled year in dollars.

Key PLEXOS inputs are included in the following worksheets:

- **Base Generating Unit Charac.:** This worksheet provides unit-level operating characteristics for non-battery units, including the unit's technology type, EIA IDs where applicable, the PLEXOS zone the unit resides in, the unit's installed capacity in both 2027 and 2035, forced outage rates, and maintenance parameters.
- **Base Batteries:** This worksheet provides unit-level operating characteristics for batteries including the PLEXOS zone the unit resides in, the max power in both 2027 and 2035, the capacity in 2027 and 2035, the minimum and maximum state of charge constraints, the charge and discharge efficiencies, and the hour-duration.
- **Transmission:** This worksheet provides detail on each BA-to-BA transmission line represented in PLEXOS including the maximum and minimum flow constraints and the wheeling charges in both directions of flow.
- **Base Load Forecasts:** This worksheet provides the hourly base load forecasts by PLEXOS zone for 2027 and 2035.
- **Load Modifying Demand Forecasts:** This worksheet provides the hourly load modifying demand forecasts for applicable PLEXOS zones for both 2027 and 2035.
- **Carbon Price:** This worksheet provides the carbon price used by PLEXOS for allowances in California.

Appendix II: Detailed Hydraulic Modeling Results

Index of Appendices / Attachments Related to Hydraulic Models

Page	Topic / Reference	Attachment Name	Privileged (Y/N)
2	Base Hydraulic Model Development	Replica of CPUC SIM01 Model Data	Y
3	1-in-10 Natural Gas Demand	Summary Demand Table 2027 and 2035	Y
3	Seasonal Storage Analysis	FTI Monthly Analysis Workpaper	Y
4	2027 Shortfall Model Results	Base 2027 Hydraulic Model Assumptions and Results	Y
4	2035 Shortall Model Results	Base 2035 Hydraulic Model Assumptions and Results	Y
4	2027 Northern Zone Expansion	Portfolio 1A 2027 Hydraulic Model Assumptions and Results	Y
4	2035 Northern Zone Expansion	Portfolio 1A 2035 Hydraulic Model Assumptions and Results	Y
4	2027 Wheeler Ridge Zone Expansion	Portfolio 1B 2027 Hydraulic Model Assumptions and Results	Y
4	2035 Wheeler Ridge Zone Expansion	Portfolio 1B 2035 Hydraulic Model Assumptions and Results	Y
5	Average Pipeline Outage Calculation	FTI Pipeline Outage Calculation SoCalGas Pipeline Outage Events 2015-2021	N
Response to CPUC Data Request			
6	2027 Shortfall Evaluation Model Transient Plots	Shortfall Model – 2027 – CPUC Requested Hydraulic Modeling Data	Y
6	2035 Shortfall Evaluation Model Transient Plots	Shortfall Model – 2035 – CPUC Requested Hydraulic Modeling Data	Y
6	2027 Northern Zone Expansion Transient Plots	Portfolio 1A – 2027 – CPUC Hydraulic Modeling Data	Y
6	2035 Northern Zone Expansion Transient Plots	Portfolio 1A – 2035 – CPUC Hydraulic Modeling Data	Y
6	2027 Wheeler Ridge Expansion Transient Plots	Portfolio 1B – 2027 – CPUC Hydraulic Modeling Data	Y
6	2035 Wheeler Ridge Expansion Transient Plots	Portfolio 1B – 2035 – CPUC Hydraulic Modeling Data	Y
6	2027 Wheeler Ridge Alternate (Kern River) Transient Plots	Portfolio 1B (alternate-Kern River) – 2027 – CPUC Hydraulic Modeling Data	Y
6	2035 Wheeler Ridge Alternate (Kern River) Transient Plots	Portfolio 1B (alternate-Kern River) – 2035 – CPUC Hydraulic Modeling Data	Y
Response to SoCalGas Data Request			
	FTI/GSC DR Response to SoCalGas DR1	FTI/GSC DR Response to SoCalGas DR1	N
	[Attachment 1 to DR Response	[Attachment 1 to DR Response	Y
	[Attachment 2 to DR Response (Northern) - 2027]	[Attachment 2 to DR Response (Northern) - 2027]	Y
	[Attachment 2 to DR Response (Northern) - 2035]	[Attachment 2 to DR Response (Northern) - 2035]	Y
	[Attachment 3 to DR Response (Wheeler Ridge) - 2027]	[Attachment 3 to DR Response (Wheeler Ridge) - 2027]	Y
	[Attachment 3 to DR Response (Wheeler Ridge) - 2027]	[Attachment 3 to DR Response (Wheeler Ridge) - 2027]	Y

Base Hydraulic Model Development – Facilities and Consistency with Past Results

As noted in detail in the report, the initial step taken to develop a hydraulic model of the SoCalGas system was to convert a CPUC provided hydraulic model (prepared by CPUC in Synergi software) to the Gregg Engineering NextGen software platform. Within this conversion, GSC incorporated all physical facilities (pipeline segments, compressor stations, regulator stations, valves, receipt points, delivery points, etc.) on the SoCalGas system as included in the CPUC Phase 2 hydraulic models.

Next, in order to ensure consistency with models developed by CPUC and SoCalGas, GSC created a steady state version of the model under flowing conditions provided by CPUC consistent with CPUC's Phase 2 SIM01 model at midnight. Specifically, CPUC provided a snapshot of receipt and delivery data (quantities and pressures) as well as operating conditions (compressor suction and discharge pressures, regulator inlet and outlet pressures, flowrates, etc.) at each location on the system.

Incorporating this data, GSC created a replica steady state model of the CPUC SIM01 (midnight) parameters in the Gregg NextGen software. The base model demonstrated a strong correlation between the GSC Gregg model results and the CPUC midnight SIM01 model. Based upon this strong correlation, this base model was used as a platform to evaluate SoCalGas system capacities under various flowing conditions.

Model results for this base model were shared with CPUC staff and the intervenors during the first Phase 3 workshop held on November 17, 2020. Further, CPUC staff posted the results of this model to its bulletin board shortly after the workshop. The results file for this base replica model is attached in Microsoft Excel format as:

[Replica of CPUC SIM 01 Midnight Model Data] – ***Privileged and Confidential***

The following provides a summary of the data included in the results file.

Compressor Data:

Flowrate, Suction/Discharge Pressures, Installed Horsepower ("HP"), HP Utilized, assumed compressor efficiency, Fuel Factor Setpoint

Nodes Data:

Receipt / Delivery quantity, receipt / delivery pressure, Elevation, MAOP, Number of Meters at Node, Setpoints (flowrate, pressure, temperature, flowing gas specific gravity, flowing gas heating value)

Meter Data:

Receipt / Delivery quantity, receipt / delivery pressure, Elevation, MAOP, Node Location, Setpoints (flowrate, pressure, temperature, flowing gas specific gravity, flowing gas heating value)

Regulator Station Data:

Flowrate, Inlet/outlet pressure, Max allowable discharge pressure, Max regulator Cv, Upstream node, downstream node, operating status

Pipe Data:

Pipe Diameter, Pipe segment length, Flowrate, Upstream node, Downstream node, pipe equation, pipe efficiency, ground temperature, pipe roughness, Heat Transfer Coefficient, Pipe

Comparison of results of CPUC SIM01 (Midnight) model to GSC Base model

Comparison of flows and pressures at each receipt and delivery pressure on the system. With flowrates identical, pressures between the two models had an absolute value variance of less than 1 psig and all receipt / delivery pressures in the GSC base model were within 5 psig of those in the CPUC SIM01 midnight model.

Summary Demand

Within the hydraulic models, GSC incorporated daily (1 in 10 Winter Peak Day) natural gas demand for the years 2027 and 2035 for Core and Noncore customers based upon the data included in the 2020 California Gas Report. Further, the daily Core and Noncore gas demand was allocated to specific hours during the day consistent with customer class hourly profiles provided by CPUC and used by CPUC in its Phase 2 evaluations.

As to EG demand, GSC incorporated daily and hourly demand at each generation facility per the results of FTI PLEXOS model runs described in detail within the report.

A summary of 1 in 10 Winter Peak Day demand requirements utilized in the hydraulic models was shared with CPUC staff and other interested parties during the final Phase 3 workshop held on November 3, 2021. Further, FTI/GSC provided CPUC staff with detailed demand requirements by delivery location, and CPUC posted the results of this model to its bulletin board shortly after the November 3 workshop. The demand file is attached in Microsoft Excel format as follows:

[Summary Demand Table 2027 and 2035] – ***Privileged and Confidential***

A listing of data included in the file includes

- Total 1 in 10 Winter Peak Day Demand for Core, Noncore and EG customer classes
- EG Demand Summary by Generation Plant Location
- Listing of Demand Served / Not Served in Shortfall Models

Seasonal Storage Analysis

In order to evaluate storage withdrawal capacity as a supply source available at SoCalGas Company operated Honor Rancho, La Goleta and Playa Del Rey Storage fields (the “Non-Aliso Storage Fields”), the FTI/GSC team developed a seasonal storage usage analysis for each of the years 2027 and 2035. In the analysis, seasonal demand, as reported in the 2020 California Gas Report under “colder than normal with low hydro” conditions, is balanced against projected flowing supplies from physical receipt points on the SoCalGas system.

Seasonal demand in excess of flowing supplies is served via the utilization of storage withdrawals from the Non-Aliso Storage Fields. Based upon the total storage withdrawals required, storage inventories as of the end of the winter season at each storage field (end of February / beginning of March) were calculated.

Finally, storage withdrawal capacity available at each of the Non-Aliso Storage Fields was calculated by applying the storage curves provided by SoCalGas to CPUC via data request in 2019[85] to the storage inventories calculated via the seasonal storage analysis.

The FTI/GSC seasonal storage analysis was presented to CPUC and other interested parties during the Phase 3 Workshop #2 held on March 30, 2021, and was posted to the CPUC website shortly thereafter. The seasonal storage analysis file is attached in Microsoft Excel format as:

[FTI Monthly Analysis Workpaper]

[85] Curves provided in SoCalGas Response Dated July 23, 2019, to CPUC-Energy Division Data Request Dated July 22, 2019, pursuant to PUC Section 583, GO 66-D and D.17-09-023.

Hydraulic Model Results Workbooks

As discussed in detail in the report, the hydraulic model of the SoCalGas system was utilized to evaluate:

- **Shortfall Analysis**: The deliverability shortfall (in 2027 and 2035) between SoCalGas capability to deliver natural gas to connected markets versus projected demand requirements under 1 in 10 Winter Peak Day conditions; and
- **Portfolio 1 Analysis**: Expansion facilities required to increase SoCalGas deliverability to meet demand requirements

The results of the hydraulic model analyses were provided to CPUC staff and other interested parties during the final Phase 3 workshop held on November 3, 2021. Subsequently, detailed workbooks illustrating hydraulic model results for each model were posted to the CPUC website. The six hydraulic model results files are attached in Microsoft Excel format as follows:

Shortfall Model Hydraulic Results

- **[Base 2027 Hydraulic Model Assumptions and Results] –** ***Privileged and Confidential***
- **[Base 2035 Hydraulic Model Assumptions and Results] –** ***Privileged and Confidential***

Northern Zone Expansion Hydraulic Model Results

- **[Portfolio 1A 2027 Hydraulic Model Assumptions and Results] –** ***Privileged and Confidential***
- **[Portfolio 1A 2035 Hydraulic Model Assumptions and Results] –** ***Privileged and Confidential***

Wheeler Ridge Zone Expansion Hydraulic Model Results

- **[Portfolio 1B 2027 Hydraulic Model Assumptions and Results] –** ***Privileged and Confidential***
- **[Portfolio 1B 2035 Hydraulic Model Assumptions and Results] –** ***Privileged and Confidential***

The following provides a summary of the data included in each of the attached hydraulic model results files.

Meter Data:

Daily Receipt / Delivery quantity, Elevation, MAOP, Node Meter Located, Gen Facility at Meter if applicable, Gen Facility EIA Code, Type Customer (core, Noncore, etc.), Applicable Hourly Profile

Nodes Data:

Receipt / Delivery quantity, Elevation, MAOP, Supply Source if Receipt Point, Delivery Zip Code, Minimum Operating Pressure, Number of Meters at Node, Setpoints (flowrate, pressure, temperature, flowing gas specific gravity, flowing gas heating value)

Regulator Station Data:

Upstream node, downstream node, setpoints (Discharge Pressure, Suction Pressure, Max Cv)

Hourly Demand Profile:

Hourly Flow Profile applied to daily demand

Model Results

- Comparison of minimum and maximum delivery pressure at each Meter/Node during the day per the hydraulic model versus allowable minimum pressure and maximum pressure
- Daily receipts and deliveries at each Meter/Node location

Pipeline Outage

As discussed in detail in the report, with respect to the Portfolio 1 (SoCalGas System Expansion) analyses, the underlying RPU assumption was set as equal to an RPU of 95 percent plus one pipeline outage.

In order to assess the average impact of one pipeline outage, the FTI/GSC team reviewed all unique pipeline facility related maintenance outages that have occurred on the SoCalGas system over the six-year period from June 2015 through June 2021. Based upon a review of this data, it was determined that the average outage of these unique events is approximately 212 MMCFD. As such, within the Portfolio 1 hydraulic model analyses, 212 MMCFD of capacity was reserved to simulate the offset of such an outage.

The FTI/GSC seasonal storage analysis was presented to CPUC and other interested parties during the Phase 3 Workshop #3 held on November 3, 2021, and was posted to the CPUC website shortly thereafter. The pipeline outage analysis file is attached in Microsoft Excel format as:

[FTI Pipeline Outage Calculation SoCalGas Pipeline Outage Events 2015-2021]

Responses to CPUC Data Request

After the third workshop was completed, CPUC staff made a request (via e-mail for additional data related to the hydraulic models and further requested that FTI/GSC include its response within the Appendices to the final version of the Report.

Specifically, CPUC staff requested that FTI/GSC provide the following 24-hour transient plots and .csv for each simulation:

1. System sum of supplies, loads and total linepack
2. Subsystems linepack
3. Storage withdrawals and discharge pressure by storage field
4. Pressure plots in load centers (Orange County, south Basin, SDG&E, valley, and coastal); A handful of nodes for each
5. Compressor stations utilization factor and flow rate
6. Compressor stations suction and discharge pressure
7. City gates flows (2 west gates, 2 X YORBA, Quigley, BREA and PUENTE)
8. City gates upstream and downstream pressures (2 west gates, 2 X YORBA, Quigley, BREA and PUENTE)
9. Crossover flows (CHINO and PRADO)
10. Operational actions

In response to this data request, the following files are included in Microsoft Excel format as attachments to the Appendix:

[Portfolio 1A – 2027 – CPUC Hydraulic Modeling Data] ***– Privileged and Confidential***

[Portfolio 1A – 2035 – CPUC Hydraulic Modeling Data] ***– Privileged and Confidential***

[Portfolio 1B – 2027 – CPUC Hydraulic Modeling Data] ***– Privileged and Confidential***

[Portfolio 1B – 2035 – CPUC Hydraulic Modeling Data] ***– Privileged and Confidential***

[Portfolio 1B (alternate-Kern River) – 2027 – CPUC Hydraulic Modeling Data][86] ***– Privileged and Confidential***

[86] Expansion facilities associated with Wheeler Ridge Zone expansions are sufficient to support required incremental deliverability to offset the shortfall requirements regardless of whether supplies are received at Wheeler Ridge or Kern River Station. Expansion Facilities incorporated in the Portfolio 1B models are identical to those included in the Portfolio 1B alternate models. The only difference in the models is the sourcing of the incremental supply (i.e., Wheeler Ridge or Kern River).

[Portfolio 1B (alternate-Kern River) – 2035 – CPUC Hydraulic Modeling Data][2] ***– Privileged and Confidential***

Each of the data points requested by CPUC have been included in these appendices.

Responses to SoCalGas Data Request

After the third workshop, SoCalGas issued a data request to the CPUC (Data Request #1 dated November 29, 2021) that included several requests for data related to the hydraulic models and hydraulic model results developed by FTI/GSC.

The Data Request is attached to this Appendix as **[SCG DR-1 to Energy Division_I1702002.pdf].**

In response to this data request, FTI/GSC the following files are included in Microsoft Excel format as attachments to the Appendix:

[FTI/GSC DR Response to SoCalGas DR1] ***– Privileged and Confidential***

[Attachment 1 to DR Response] ***– Privileged and Confidential***

[Attachment 2 to DR Response (Northern) - 2027] ***– Privileged and Confidential***

[Attachment 2 to DR Response (Northern) - 2035] ***– Privileged and Confidential***

[Attachment 3 to DR Response (Wheeler Ridge) - 2027] ***– Privileged and Confidential***

[Attachment 3 to DR Response (Wheeler Ridge) - 2027] ***– Privileged and Confidential***

Each of the data points requested by SoCalGas have been included in these appendices.

Appendix III: Detailed Financial Modeling Results

Investment Cost Analysis

Portfolio 1

New Pipeline Loops

Total capital costs pertaining to the addition of the new pipeline loops were calculated at $9,050,000 per mile of new pipeline, based on the average capital costs per mile (in $2019) for similar projects, the SoCalGas *Adelanto-Moreno Pipeline*[87] filed with the CPUC in 2014 and SDG&E's Line 360 (Rainbow Station to line 2010)[88] filed with the CPUC in March 2016. O&M costs were calculated at 0.05 percent of capital costs based on the average estimated O&M costs as a percentage of capital costs for SoCalGas Adelanto-Morena Pipeline Project and SDG&E's Line 360 Project. The calculation of Capital and O&M costs are shown in Table 45 below.

Table 45: Gas Pipeline Capital and O&M Costs

	SoCalGas, Adelanto-Morena Pipeline	SDG&E, Line 360	Project Average
Pipeline Length (Miles)	63	47	
Pipeline Diameter (Inches)	36	36	
Total Cost (Nominal)	$484,545,193	$426,800,000	
Labor Cost (Nominal)	$17,495,082	$18,200,000	
Non-Labor Cost (Nominal)	$467,050,111	$408,600,000	
Total Cost per Mile (Nominal)	$7,691,194	$9,080,851	
Annual O&M Costs (Nominal)	$200,000	$240,000	
Annual O&M Percent of Capital Costs	**0.04%**	**0.06%**	**0.05%**
Total Cost per Mile (2019$)	**$8,305,908**	**$9,795,007**	**$9,050,000**

Quigley Regulator Station Expansion

The cost to expand the Quigley Regulator Station was calculated at $3,410,000 (in 2019$) based on analysis performed by SoCalGas in its 2011 Gas System Expansion Report,[89] which evaluated a rebuild of the Quigley Station with a higher flow rate capacity that would allow receipt of up to 865 MMCFD at the Wheeler Ridge receipt point.

[87] CPUC Docket A.13-12-013, SoCalGas Buczkowski Supplemental Testimony – Attachment A Filed November 2014.
[88] CPUC Docket A.15-09-013, SDG&E N. Navin Direct Cost and Schedule Workpapers Filed March 2016.
[89] SoCalGas 2011 Gas System Expansion Report filed December 8, 2011, pursuant to CPUC Decision (D.) 07-12-019

Capital Recovery Factor

Annual capital and O&M costs were calculated using a Capital Recovery Factor of 6.35 percent as previously shown in Table 8.

Portfolio 1a

Upstream Capacity Costs

Portfolio 1a evaluates the additional new pipeline loops that would allow for supplies to be accessed via additional upstream pipeline supply, which would necessitate additional costs for upstream transportation capacity. The cost of upstream capacity necessary to transport into the LA Basin was calculated by converting the prevailing firm transportation rate Sempra receives[90] for Permian to Ehrenburg to 2019$/MMCFD and multiplying that rate by the daily Gas Shortfall amounts in 2027 and 2035, as shown in Table 46 below.[91]

Table 46: Portfolio 1a Annual Upstream Capacity Cost

	2027	2035
Gas Shortfall (MMCFD)	395	323
Portfolio 1A Incremental Upstream Capacity Rate (2019$/MMCFD)	$362	$362
Daily Upstream Capacity Cost (2019$/day)	$143,000	$117,000
Annual Upstream Capacity Cost (2019$/year)	**$52,195,000**	**$42,705,000**

[90] Sempra Negotiated Rate is equal to El Paso current maximum tariff "California Rate" per Section 1.6 of El Paso's FERC Gas Tariff.

[91] El Paso Natural Gas FERC Gas Tariff - Statement of Negotiated Rates (Section 5.16, Tariff Sheet 54) - Sempra Contract from Permian to Ehrenburg

Capital and O&M Costs 2027 & 2035

Table 47: Portfolio 1a Levelized Capital and O&M Cost – Pipeline

	2027	2035
Total New Pipeline Length (Miles)	84	42
New Pipeline Total Capital Cost per Mile (2019$)	$9,050,000	$9,050,000
New Pipeline Total Capital Cost (2019$)	$755,675,000	$375,575,000
New Pipeline Total O&M Cost (% of Total Capital Costs)	0.05%	0.05%
New Pipeline Total O&M Cost (2019$)	$378,000	$188,000
Total New Pipeline Capital and O&M Cost (2019$)	$756,053,000	$375,763,000
Capital Recovery Factor	6.35%	6.35%
Levelized Capital and O&M Cost (2019$/year)	**$48,009,000**	**$23,861,000**

Table 48: Portfolio 1a & 1b Levelized Capital and O&M Cost – Quigley Pressure Limiting Station Upgrade

Quigley Regulator Station Expansion Total Capital Costs (2019$)	3,410,000
Total O&M Cost (% of Total Capital Costs)	0.05%
Total O&M Cost (2019$)	$1,705
Total Capital and O&M Cost (2019$)	$3,411,705
Capital Recovery Factor	6.35%
Levelized Capital and O&M Cost (2019$/year)	**$217,000**

Portfolio 1b

Portfolio 1b evaluates the addition of a new pipeline loop that would allow for supplies to be accessed via storage withdrawals from facilities on the PG&E system, such as Gill Ranch, which would necessitate additional costs for both storage and transportation capacity on PG&E's system.

Upstream Capacity Costs

The cost of upstream capacity on the PG&E system necessary to transport into the LA Basin was estimated at $105 million in 2027 and $86 million in 2035, which was calculated by converting the prevailing PG&E firm transportation rate into 2019$/MMCFD and multiplying that rate by the respective Shortfall amounts in 2027 and 2035, as shown in Table 49 below.

Table 49: Portfolio 1b Annual Upstream Capacity Cost

	2027	2035
Shortfall (MMCFD)	395	323
Portfolio 1B Incremental Upstream Capacity Cost (2019$/MMCFD)	$730	$730
Daily Upstream Capacity Cost (2019$)	$289,000	$236,000
Annual Upstream Capacity Costs (2019$)	**$105,485,000**	**$86,140,000**

Storage Capacity

Storage capacity costs for Portfolio 1b were based on the average cost of withdrawal capacity (2019$/MMCFD) at the Gill Ranch storage facility located on PG&E's system, which was multiplied by the amount of storage capacity that would be required, represented by the Gas Shortfall amounts. Storage capacity costs were estimated to be approximately $22 million in 2027 and $18 million in 2035, as shown in Table 50 below.

Table 50: Portfolio 1b Annual Storage Capacity Cost

	PGE Gill Ranch	2027	2035
Injection Capacity (MMCFD)[92]	56	221	181
Inventory (BCF)	2.00	7.90	6.46
Withdrawal Capacity (MMCFD)[93]	100	395	323
Annual Storage Capacity Cost [94]	**$5,461,000**	**$21,571,000**	**$17,639,000**

[92] PGE Gill Ranch capacities per Table 3 of Pacific Gas and Electric Company 2019 GAS TRANSMISSION AND STORAGE RATE CASE WORKPAPERS SUPPORTING CHAPTER 11, NATURAL GAS STORAGE STRATEGY (NGSS) WORKPAPER FOR STORAGE SERVICES AND COST ALLOCATION

[93] Proposed SoCalGas Capacity based upon withdrawal quantity equal to "shortfall" for given year and annual cost developed based upon gross up of PGE costs.

[94] PGE Gill Ranch Annual Costs per Tables 10-11 and 10-12 of Pacific Gas and Electric Company Chapter 10 Gas System Operations as included within PACIFIC GAS AND ELECTRIC COMPANY 2019 GAS TRANSMISSION AND STORAGE RATE CASE NOVEMBER 17, 2017 PREPARED TESTIMONY WITH ERRATA VOLUME 1 OF 2

Capital and O&M Costs 2027 & 2035

Table 51: Portfolio 1b Levelized Capital and O&M Cost – Pipeline

	2027	2035
Total New Pipeline Length (Miles)	34.8	24.8
New Pipeline Total Capital Cost per Mile (2019$)	$9,050,000	$9,050,000
New Pipeline Total Capital Cost (2019$)	$314,940,000	$224,440,000
New Pipeline Total O&M Cost (% of Total Capital Costs)	0.05%	0.05%
New Pipeline Total O&M Cost (2019$)	$157,470	$112,220
Total New Pipeline Capital and O&M Cost (2019$)	$315,097,470	$224,552,220
Capital Recovery Factor	6.35%	6.35%
Levelized Capital and O&M Cost (2019$/year)	**$20,009,000**	**$14,259,000**

Portfolio 2

Portfolio 2 involves a combination of Building Electrification, electric energy efficiency, and Noncore demand response to meet the Shortfall in 2027 and 2035. The following subsections describe the cost assumptions used for this combination of solutions.

Building Electrification

The "Moderate Case" net cost projections in the 2021 CEC California Building Decarbonization Assessment were used to estimate the net investment cost of achieving the amount of Building Electrification assessed in Portfolio 2. In the Moderate Case, the total net costs were projected to be $6.2 billion (2020$) and the total incremental electric demand was estimated to be 22,885 GWh.[95] CEC's projection of the net cost of $6.2 billion includes $7.4 billion in costs pertaining to net energy cost increases for end-users transitioning from gas fueled equipment to electric fueled equipment and $1.2 billion in investment cost savings due to the deferred costs of new gas equipment exceeding that of the incurred costs of new electric equipment. In this study, the costs and benefits related to fuel switching were estimated through production cost modeling, as described in "Section III.C. Base Case Modeling Key Inputs and Results," and as such only the investment cost savings of $1.2 billion from the 2021 CEC California Building Decarbonization Assessment were incorporated into total investment costs for the purposes of cost benefit analysis.

[95] 2021 CEC California Building Decarbonization Assessment, Table 3

These savings equate to total per unit savings (2019$/GWh) of approximately $52,000 for incremental electric demand resulting from Building Electrification, or approximately $3,300 on an annual levelized basis, as shown in Table 52 below.

Table 52: Electrification Levelized Annual Investment Savings

	Moderate Case
Total Discounted Net Investment Savings (All CA, 2020$)	$1,194,000,000
Total GWh Added (All CA)	22,885
Total Discounted Net Investment Savings/GWh Added (All CA, 2020$/GWh)	$52,174
Total Discounted Net Investment Savings/GWh Added (All CA, 2019$/GWh)	$51,538
Capital Recovery Factor (Real)	6.35%
Total Levelized Annual Investment Savings/GWh Added (All CA, 2019$/GWh)	**$3,273**

SoCalGas and SDG&E's incremental electric demand was estimated to be 6,757 GWh in 2027 and 12,846 GWh in 2035 under the CEC's Moderate Case, as discussed in Portfolio #2: Gas Demand Reduction. Total levelized annual investment savings (2019$) were estimated to be approximately $22 million in 2027 and $42 million in 2035, as shown in Table 53 below.

Table 53: Levelized Annual Investment Savings for Electrification, SoCalGas & SDGE Share

	2027	2035
Portfolio 2 Increase in Total Electric Demand (SoCalGas and SDG&E), GWh	6,757	12,846
Levelized Annual Investment Savings/GWh Added (All CA, 2019$/GWh)	$3,273	$3,273
Levelized Annual Investment Savings (SoCalGas & SDGE, 2019$)	**$22,113,000**	**$42,041,000**

Electric Energy Efficiency

Electric Energy Efficiency costs in this study were estimated based on the projected program costs evaluated in the 2021 Guidehouse Report.[96] To identify incremental costs beyond those that would be reasonably expected absent any new actions, the cumulative costs necessary to achieve the savings

[96] Data was sourced directly from the 2021 Potential and Goals Study Results Viewer, an online Tableau dashboard developed as part of the 2021 Guidehouse Report. All metrics presented in dollars were assumed to have a nominal year of 2019. https://public.tableau.com/app/profile/2021.cpuc.pg.study/viz/CPUC_V01_16184220382340/LandingPage

evaluated in the TRC High case were compared against the costs the achieve the savings evaluated in the "business-as-usual" TRC Reference case for both 2027 and 2035.[97]

The calculation of the increase in levelized annual costs necessary to achieve the incremental Electric Energy Efficiency savings considered in the TRC High case is shown in Table 54 below.

Table 54: Levelized Annual Increase in Program Costs, TRC High Case (2019$)

	2027	2035
Cumulative Program Costs, TRC Reference Case (2019$)	$457,667,169	$567,163,031
Cumulative Program Costs, TRC High Case (2019$)	$601,829,129	$860,067,505
Increase in Cumulative Program Costs (2019$)	$144,161,960	$292,904,474
Capital Recovery Factor	6.35%	6.35%
Levelized Annual Increase in Program Costs (2019$)	**$9,154,000**	**$18,599,000**

Noncore Demand Response

Noncore Demand Response costs in this study were estimated based on the most recent results of National Grid's Gas Demand Response programs, operated in the state of New York during the winter months for gas year 2020/21.[98] Program costs were assessed for National Grid's 'Daily Demand Response' program, which is targeted at "large commercial, industrial, and multi-family firm service customers capable of reducing peak day gas loads," similar to the Noncore Demand Response program considered in Portfolio 2 and described in "Section V.B. Portfolio #2: Gas Demand Reduction."

National Grid's Daily Demand Response program allows for customer participation both with and without Direct Load Control ("DLC"), with two different reduction windows for each option, for a total of four distinct program offerings. The reduction windows available are a 6 hour period from 4 AM – 10 AM and two 4 hour periods, from 6 AM – 10 AM and 5 PM – 9 PM. For the 2020-2021 winter season, 96 percent of participating customers elected an option with two 4 hour periods and 69 percent of participating customers elected an option with DLC. Participating customers are provided no less than 20 hours advance notice prior to a curtailment event.

For the purposes of this study, only the costs associated with National Grid's DLC program options were evaluated, consistent with the framework of the Noncore Demand Response program considered in Portfolio 2. There are two primary cost components pertaining to National Grid's Daily Demand

[97] The 2021 Guidehouse Report contains projections through 2032 which were linearly extrapolated to 2035.
[98] National Grid Gas Demand Response 2020-21 Annual Report, June 14,2021. https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B401290B9-FE59-4F47-B886-CDE01A38522A%7D

Response programs with DLC, a monthly Reservation Payment that is paid in each of the five winter months from November through March and a Performance Payment that based on the amount of demand reduction achieved during an event. The maximum monthly Reservation Payment rate for customers choosing a DLC program option was $52/Dth, and the Performance Payment rate was $7/Dth for all DLC program options.

In order to estimate Portfolio 2 costs pertaining to Noncore Demand Response, proxy rates were converted into a single rate expressed in 2019$/MMCFD, which reflects a scenario where the full amount of demand reduction enrolled in a given winter season is called upon during a single event with a 100 percent participation rate, i.e., all customers reduce load at 100 percent of the daily maximum amount enrolled.[99] The total Noncore Demand Response rate per MMCFD of demand reduction was estimated to be approximately $255,000 (2019$), as calculated in Table 55 below.

Table 55: Noncore Demand Response Costs per MMCFD of Demand Reduction

Monthly Reservation Payment Rate (2020$/Dth/Month)	$52.00
Monthly Reservation Payment Rate (2020$/Dth)	$260.00
Performance Payment Rate (2020$/Dth)	$7.00
Total Payment Rate (2020$/Dth)	$267.00
Total Payment Rate (2019$/Dth)	$263.74
Total Payment Rate (2019$/MMCFD)	**$255,000**

As discussed in Portfolio #2: Gas Demand Reduction, after incorporating the impacts of Building Electrification and Electric Energy Efficiency, the remaining Gas Shortfall is approximately 67 MMCFD in 2027 and 0 MMCFD in 2035.[100] The annual cost of meeting the remaining Gas Shortfall of 67 MMCFD in 2027 was estimated to be approximately $17 million (2019$), as calculated in Table 56 below.

[99] This is consistent with the results of National Grid's 2020-2021 program, which featured a performance rate of 99% for customers with DLC enabled during the two test events called during the winter season.
[100] Building Electrification and Electric Energy Efficiency adequately address the Shortfall in 2035 and Noncore Demand Response is not necessary.

Table 56: Portfolio 2 Noncore Demand Response Costs

Total Payment Rate (2019$/MMCFD)	$255,172
2027 Shortfall (MMCFD)	395
2027 Shortfall Reduction Related to Electrification and Electric Energy Efficiency (MMCFD)	328
2027 Remaining Shortfall (MMFCD)	67
Total 2027 Noncore Demand Response Cost (2019$)	**$17,097,000**

Portfolio 3

Total capital and operating costs pertaining to the addition of new generation capacity within California were estimated based on projections for the four specific generation resources incorporated into the Portfolio 3 solution, as detailed in "Section V.C. Portfolio #3: Generator Additions."

Wind

Capital and O&M costs pertaining to the development of new wind resources were sourced from the NREL 2021 ATB.[101] For 2027, capital costs were estimated at $1,083/kW of capacity and O&M costs were estimated at approximately $40/kW-year. For 2035, capital costs were estimated at $903/kW of capacity and O&M costs were estimated at approximately $37/kW-year.

Total capital and O&M costs pertaining to the development of new wind resources in Portfolio 3 were adjusted based on the expected continuation of the Production Tax Credit ("PTC") for renewable energy resources, which provides a tax credit on a production basis for qualifying resources, in some form. For the purposes of this study, in 2027 it was assumed that the PTC will remain available at 60 percent of the 2019 effective value of $21.37/MWh, as shown in the NREL 2021 ATB for land based wind resources, and by 2035 the PTC for wind resources will have expired. In order to estimate the financial impact of the PTC on projected levelized annual costs for wind resources, the projected generation for 2027 was estimated based on the nameplate capacity of the wind generation resources and a capacity factor of 35 percent based on the NREL ATB Wind Toolkit.

Annual levelized capital and O&M costs, including PTC impacts, are estimated to be $104 million in 2027 and $128 million in 2035, as shown in Table 57 below.

[101] 2021 Annual Technology Baseline (ATB) Cost and Performance Data for Electricity Generation Technologies. https://data.openei.org/submissions/4129

Table 57: Portfolio 3 Capital and O&M Costs – Wind

	2027	2035
Capacity (MW)	1,497	1,355
Capital Cost (2019$/MW)	$1,082,545	$902,500
Total Capital Cost (2019$)	$1,620,570,545	$1,222,887,500
Capital Recovery Factor (Real)	6.35%	6.35%
Levelized Annual Capital Cost (2019$)	$102,906,230	$77,653,356
Fixed O&M Cost (2019$/MW-Year)	$40,055	$37,489
Annual Fixed O&M Cost (2019$)	$59,961,655	$50,798,103
Total Annual Capital and O&M Costs (2019$), Before Tax Credits	**$162,867,884**	**$128,451,459**
Land Based Wind Capacity Factor - 2027	35%	35%
Total Energy per Year (MWh)	4,589,802	4,154,430
60% PTC Tax Credit (2019$/MWh)	$12.82	$0.00
PTC Annual Cost Reduction (2019$)	$58,853,417	$0
Total Annual Capital and O&M Costs (2019$), After Tax Credits	**$104,014,000**	**$128,451,000**

Geothermal

Capital and O&M costs pertaining to the development of new geothermal resources were sourced from the NREL 2021 ATB. For 2027, capital costs were estimated at $5,833/kW of capacity and O&M costs were estimated at approximately $130/kW-year. For 2035, capital costs were estimated at $5,413/kW of capacity and O&M costs were estimated at approximately $128/kW-year.

Total capital and O&M costs pertaining to the development of new geothermal resources in Portfolio 3 were adjusted based on the permanent Investment Tax Credit ("ITC") for new geothermal resources, which provides a tax credit of 10 percent on investments costs for qualifying resources.[102] In order to estimate the financial impact of the ITC on projected levelized annual costs for geothermal resources, total projected capital costs were reduced by 10 percent in both 2027 and 2035.

[102] Congressional Research Service, "The Energy Credit or Energy Investment Tax Credit (ITC)" https://crsreports.congress.gov/product/pdf/IF/IF10479

Annual levelized capital and O&M costs, including ITC impacts, are estimated to be $213 million in 2027 and $182 million in 2035, as shown in Table 58 below.

Table 58: Portfolio 3 Capital and O&M Costs - Geothermal

	2027	2035
Capacity (MW)	460	416
Capital Cost (2019$/MW)	$5,832,713	$5,412,793
Total Capital Cost (2019$)	$2,683,047,891	$2,251,721,767
Capital Recovery Factor (Real)	6.35%	6.35%
Levelized Annual Capital Cost (2019$)	$170,373,541	$142,984,332
Fixed O&M Cost (2019$/MW-Year)	$130,420	$127,576
Annual Fixed O&M Cost (2019$)	$59,993,422	$53,071,478
Total Annual Capital and O&M Costs (2019$), Before Tax Credits	**$230,366,963**	**$196,055,810**
ITC Tax Credit (Percentage of Capital Costs)	10%	10%
ITC Annual Cost Reduction (2019$)	$17,037,354	$14,298,433
Total Annual Capital and O&M Costs (2019$), After Tax Credits	**$213,330,000**	**$181,757,000**

Storage – 4 Hour Duration

Capital and O&M costs pertaining to the development of new 4h duration battery storage resources were sourced from the NREL 2021 ATB. For 2027, capital costs were estimated at $1,092/kW of capacity and O&M costs were estimated at approximately $27/kW-year. For 2035, capital costs were estimated at $981/kW of capacity and O&M costs were estimated at approximately $25/kW-year.

Annual levelized capital and O&M costs are estimated to be $190 million in 2027 and $155 million in 2035, as shown in Table 59 below.

Table 59: Portfolio 3 Capital and O&M Costs – 4h Battery Storage

	2027	2035
Capacity (MW)	1,968	1,781
Capital Cost (2019$/MW)	$1,092,309	$980,885
Total Capital Cost (2019$)	$2,149,664,584	$1,746,956,897
Capital Recovery Factor (Real)	6.35%	6.35%
Levelized Annual Capital Cost (2019$)	$136,503,701	$110,931,763
Fixed O&M Cost (2019$/MW-Year)	$27,308	$24,522
Annual Fixed O&M Cost (2019$)	$53,741,615	$43,673,922
Total Annual Capital and O&M Costs (2019$)	**$190,245,000**	**$154,606,000**

Storage – Long Duration

Capital and O&M costs pertaining to the development of new long duration pumped hydro storage resources were sourced from the 2020 Grid Energy Storage Technology Cost and Performance Assessment prepared by the Pacific Northwest National Laboratory for the U.S. Department of Energy.[103] For 2027, capital costs were estimated at $4,364/kW of capacity and O&M costs were estimated at approximately $78/kW-year. For 2035, capital costs were estimated at $4,364/kW of capacity and O&M costs were estimated at approximately $79/kW-year.

Annual levelized capital and O&M costs are estimated to be $145 million in 2027 and $132 million in 2035, as shown in Table 60 below.

[103] https://www.pnnl.gov/sites/default/files/media/file/Final%20-%20ESGC%20Cost%20Performance%20Report%2012-11-2020.pdf

Table 60: Portfolio 3 Capital and O&M Costs – Long Duration Pumped Hydro Storage

	2027	2035
Capacity (MW)	409	370
Capital Cost (2019$/MW)	$4,364,211	$4,364,211
Total Capital Cost (2019$)	$1,784,962,476	$1,614,758,230
Capital Recovery Factor (Real)	6.35%	6.35%
Levelized Annual Capital Cost (2019$)	$113,345,117	$102,537,148
Fixed O&M Cost (Percent of Capital)	1.79%	1.82%
Fixed O&M Cost (2019$/MW-Year)	$78,294	$79,429
Annual Fixed O&M Cost (2019$)	$32,022,227	$29,388,600
Total Annual Capital and O&M Costs (2019$)	**$145,367,000**	**$131,926,000**

Portfolio 4

Total capital costs pertaining to the addition of new electric transmission capacity into California were estimated based on the average estimated capital costs (2019$/MW of capacity) for similar transmission projects. The average capital cost was estimated to be approximately $687,000/MW, as shown in Table 61 below.

Table 61: Portfolio 4a and 4b Transmission Capital Costs per MW of Capacity

Project	Capacity (MW)	Length (miles)	Cost ($ millions)	Estimated Cost Year	Cost (2019$)	Cost-MW (2019$/MW)
Desert Link[104]	200	60	$144,000,000	2015	$155,324,757	$776,624
North Gila[105]	1,250	97	$291,000,000	2018	$296,272,852	$237,018
Ten West[106]	969	114	$365,000,000	2018	$371,613,714	$383,502
Pacific Transmission Expansion Project[107]	2,000	230	$1,850,000,000	2020	$1,827,454,977	$913,727
One Nevada Line[108]	800	231	$552,000,000	2013	$605,788,467	$757,236
Southwest Intertie[109]	2,000	275	$525,000,000	2018	$534,512,877	$267,256
GreenLink West + GreenLinkNorth[110]	1,525	319	$2,537,525,369	Multiple Years	$2,213,357,296	$1,451,382
Project Average	**1,249**	**189**	**$894,932,196**		**$857,760,706**	**$687,000**

As shown in Table 62 below, levelized annual capital costs in 2035 were estimated to be approximately $125 million for Portfolio 4a, which considers additional transmission capacity of 2,875 MW and $87 million for Portfolio 4b, which considers additional transmission capacity of 2,000 MW. Annual O&M costs were estimated at 0.05 percent of levelized capital costs, or approximately $63,000 for Portfolio 4a and $44,000 for Portfolio 4b.

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105 *North Gila-Imperial Valley #2 Transmission Project ITP Evaluation Process Plan*. 14 June 2018. <https://www.caiso.com/Documents/North_Gila-IV2_Project_Interregional_Transmission_Project_Evaluation_Plan.pdf>.

106 Rebuttal Testimony of Yi Zhang on Behalf of The California Independet System Operator, Application 16-10-012. The California Independent System Operator. n.d. <http://www.caiso.com/Documents/Jun18-2020-RebuttalTestimony-YiZhang-DCRTransmission-TenWestLinkProject-A16-10-012.pdf>.

107 Western Grid Development. Request for Study of Pacific Transmission Expansion Project (PTEP) as an Alternative to LCR Capacity in the 2030 LT LCR Study. 8 October 2020. <http://www.caiso.com/Documents/WGDComments-2020-2021TransmissionPlanningProcess-Sept23-24-2020StakeholderCall.pdf>.

108 NV Energy. "Form 10-K 2012." 2012.

109 LS Power. Great Basin Transmission ITP Submission to California ISO. May 2018. <https://www.caiso.com/Documents/SWIPNorthProjectSummary.pdf>.

110 Testimony of John McGinley, Carolyn Barbash, and Sachin Verma Supporting Nevada Energy's submittal for Fourth Amendment to the 2018 Joint Integrated Resource Plan, Vol 2 of 9, Docket #: 20-07-023 and NV Energy, GreenLink Nevada, https://lands.nv.gov/uploads/meeting_minutes/E2021-098.pdf, October 2020

Table 62: Portfolio 4a and 4b Levelized Annual Capital and O&M Costs

	Portfolio 4a	Portfolio 4b
Incremental Transmission Capacity Added (MW)	2,875	2,000
Portfolio 4 Cost per MW of Transmission Capacity (2019$/MW)	$687,000	$687,000
Total Incremental Transmission Capacity Cost (2019$)	$1,975,125,000	$1,374,000,000
Capital Recovery Factor (Real)	6.35%	6.35%
Levelized Annual Incremental Transmission Capacity Cost (2019$)	$125,420,438	$87,249,000
Total O&M Cost (% of Total Capital Costs)	0.05%	0.05%
Levelized Annual Total O&M Cost (2019$)	$62,710	$43,625
Levelized Total Annual Capital and O&M Cost (2019$)	**$125,483,000**	**$87,293,000**

Portfolio 5

The investment costs for each Portfolio 5 solution were estimated by applying the applicable investment costs for the Portfolios on which each Portfolio 5 solution was based, i.e., the "Basis Portfolios," to the corresponding percentage of each respective Basis Portfolio incorporated into the Portfolio 5 solutions, as shown in Table 63 below.

Table 63: Portfolio 5 Investment Cost Calculation (2019$)

Portfolio 5 Scenario	Year	Percent of Basis Portfolio	Basis Portfolio	Basis Portfolio Investment Costs	Portfolio 5 Investment Costs
Portfolio 5a	2027	17%	Portfolio 3	$652,957,000	$111,003,000
Portfolio 5b	2027	59%	Portfolio 3	$652,957,000	$381,980,000
Portfolio 5c	2027	79%	Portfolio 3	$652,957,000	$517,142,000
Portfolio 5a	2027	100%	Portfolio 2	($12,958,716)	($12,959,000)
Portfolio 5b	2027	50%	Portfolio 2	($12,958,716)	($6,479,000)
Portfolio 5c	2027	25%	Portfolio 2	($12,958,716)	($3,240,000)
Portfolio 5d	2035	25%	Portfolio 4a	$125,483,000	$30,994,000
Portfolio 5e	2035	62%	Portfolio 4a	$125,483,000	$78,301,000
Portfolio 5f	2035	81%	Portfolio 4a	$125,483,000	$101,892,000
Portfolio 5d	2035	40%	Portfolio 2	($23,441,566)	($9,377,000)
Portfolio 5e	2035	20%	Portfolio 2	($23,441,566)	($4,688,000)
Portfolio 5f	2035	10%	Portfolio 2	($23,441,566)	($2,344,000)

Total investment costs for each Portfolio 5 solution are presented in Table 64 below.

Table 64: Portfolio 5 Total Investment Costs (2019$)

Portfolio 5 Solution	Year	Total Investment Costs
Portfolio 5a	2027	$98,044,000
Portfolio 5b	2027	$375,501,000
Portfolio 5c	2027	$513,902,000
Portfolio 5d	2035	$21,617,000
Portfolio 5e	2035	$73,613,000
Portfolio 5f	2035	$99,548,000

Market Impact Cost-Benefit Analysis

The 2027 and 2035 electric and gas market impacts for each Portfolio solution, applicable to all of California, were estimated based on outputs generated using the software tools described in "Section III.B. Summary of Supporting Models."

The specific data elements that were used to calculate electric and gas market impacts are shown below in Table 65.

Table 65: Summary of Electric and Gas Market Impact Data Elements and Calculations

	Metric	Source	Calculation
a	Annual Electric Demand (GWh)	PLEXOS Modeling Output	N/A
b	Average Electricity Price (2019$/MWh)	PLEXOS Modeling Output	N/A
c	Annual Electricity Cost (2019$)	Calculation	c = (a * b)
d	Annual CO_2 Emissions, Electricity (metric tons)[111]	PLEXOS Modeling Output	N/A
e	Annual CO_2 Emissions Cost, Electricity (2019$)	Calculation	e = (d * SCC)
f	Annual Gas Demand, EG (MMCF)	PLEXOS Modeling Output	N/A
g	Annual Gas Demand - Non-EG (MMCF)	Calculation	g = (Total Gas Demand - f)
h	Average Gas Price (2019$/MCF)	PLEXOS/GPCM Modeling Output	N/A
i	Annual Gas Cost (2019$)	Calculation	i = [(f + g) * h]
j	Annual CO_2 Emissions, Non-EG Gas (metric tons)	Calculation	j = (g * Gas Emissions Factor)
k	Annual CO_2 Emissions Cost, Non-EG Gas (2019$)	Calculation	k = (j * SCC)

Electric Market Impacts

2027 and 2035 electric market impacts are summarized below in Table 66 and Table 67, respectively.

[111] Includes emissions for gas-fired Electric Generation.

Table 66: 2027 Electric Market Impacts

Portfolio	Annual Electric Demand (GWh)	Average Electricity Price (2019$/MWh)	Annual Electricity Cost (2019$)	Annual CO_2 Emissions, Electricity (metric tons)	Annual CO_2 Emissions Cost, Electricity (2019$)
Base Case	317,608	$44.11	$14,009,281,958	37,270,268	$2,150,494,439
Portfolio 2	319,247	$44.45	$14,191,366,178	37,472,873	$2,162,184,744
Portfolio 3	319,387	$42.66	$13,623,705,367	36,027,373	$2,078,779,449
Portfolio 5A	319,566	$44.15	$14,107,550,104	37,232,058	$2,148,289,751
Portfolio 5B	319,471	$43.41	$13,867,553,782	36,627,311	$2,113,395,832
Portfolio 5C	319,412	$43.08	$13,760,646,197	36,304,024	$2,094,742,212

Table 67: 2035 Electric Market Impacts

Portfolio	Annual Electric Demand (GWh)	Average Electricity Price (2019$/MWh)	Annual Electricity Cost (2019$)	Annual CO_2 Emissions, Electricity (metric tons)	Annual CO_2 Emissions Cost, Electricity (2019$)
Base Case	317,248	$47.02	$14,917,655,324	34,655,206	$2,294,174,660
Portfolio 2	320,474	$48.51	$15,546,968,560	35,235,605	$2,332,597,069
Portfolio 3	319,934	$44.82	$14,338,545,570	33,583,180	$2,223,206,495
Portfolio 4a	317,351	$46.63	$14,797,022,775	34,593,713	$2,290,103,805
Portfolio 4b	317,303	$46.64	$14,798,264,933	34,689,868	$2,296,469,246
Portfolio 5d	318,578	$47.47	$15,121,963,812	34,854,900	$2,307,394,365
Portfolio 5e	317,972	$47.06	$14,963,091,401	34,700,044	$2,297,142,938
Portfolio 5f	317,654	$46.81	$14,869,130,959	34,641,361	$2,293,258,124

Gas Market Impacts

2027 and 2035 gas market impacts are summarized below in Table 68 and Table 69, respectively.

Table 68: 2027 Gas Market Impacts

Portfolio	Annual Gas Demand, EG (MMCF)	Annual Gas Demand - Non-EG (MMCF)	Average Gas Price (2019$/MCF)	Annual Gas Cost (2019$)	Annual CO_2 Emissions, Non-EG Gas (metric tons)	Annual CO_2 Emissions Cost, Non-EG Gas (2019$)
Base Case	560,468	486,180	$3.477	$3,639,229,790	24,888,320	$1,436,056,086
Portfolio 2	563,124	445,953	$3.479	$3,510,738,425	22,829,061	$1,317,236,831
Portfolio 3	543,394	486,180	$3.461	$3,563,840,186	24,888,320	$1,436,056,086
Portfolio 5A	560,245	445,953	$3.486	$3,507,768,116	22,829,061	$1,317,236,831
Portfolio 5B	551,353	466,067	$3.486	$3,546,890,315	23,858,691	$1,376,646,459
Portfolio 5C	547,214	476,123	$3.486	$3,567,517,871	24,373,506	$1,406,351,273

Table 69: 2035 Gas Market Impacts

Portfolio	Annual Gas Demand, EG (MMCF)	Annual Gas Demand - Non-EG (MMCF)	Average Gas Price (2019$/MCF)	Annual Gas Cost (2019$)	Annual CO_2 Emissions, Non-EG Gas (metric tons)	Annual CO_2 Emissions Cost, Non-EG Gas (2019$)
Base Case	511,102	459,170	$4.078	$3,956,340,752	23,505,636	$1,556,073,098
Portfolio 2	519,740	428,579	$4.077	$3,866,446,389	21,939,659	$1,452,405,449
Portfolio 3	495,571	459,170	$4.058	$3,874,111,158	23,505,636	$1,556,073,098
Portfolio 4a	509,785	459,170	$4.075	$3,948,876,690	23,505,636	$1,556,073,098
Portfolio 4b	508,921	459,170	$4.073	$3,943,355,405	23,505,636	$1,556,073,098
Portfolio 5d	519,248	446,934	$4.086	$3,948,064,384	22,879,245	$1,514,606,038
Portfolio 5e	511,469	453,052	$4.078	$3,932,947,141	23,192,441	$1,535,339,568
Portfolio 5f	510,551	456,111	$4.077	$3,941,082,642	23,349,038	$1,545,706,333

Resource Adequacy Benefits

Resource adequacy ("RA") refers to the ability of the electric systems to supply the aggregate electrical demand and energy requirements of their customers at all times, taking into account physical characteristics of the transmission system such as transmission ratings and scheduled and reasonably expected unscheduled outages of system elements.

In California, RA is a central consideration in the state's Integrated Resource Plan ("IRP"). Because RA deals with resource adequacy for the system in its entirety, it is also referred to as "system RA."

The level of system resources required is calculated in the IRP in three steps:

First, the RESOLVE model is used to project the level, timing and mix of resource additions (including imports into California) against a planning reserve margin standard of 15 percent - i.e., each Load Serving Entity must have generating capacity equal to or greater than 115 percent of its projected peak load.

Second, the operational performance of the 15 percent reserve margin is verified by ensuring that the resources in the plan satisfy the 1-in-10 LOLE standard using the SERVM model. To the extent the 15 percent reserve margin standard results in resources that are unable to meet the 1 in 10 LOLE standard, additional generic resources are added until the standard is met.

All resources – existing and new – contribute to resource adequacy and their contribution to resource adequacy is referred to as Net Qualifying Capacity ("NQC"). For conventional resources, small adjustments may be required to translate their installed capacity (or nameplate capacity) to NQC.

Renewable resources, notably wind and solar, however, exhibit considerable variability in the energy they provide by hour of the day. For these resources, the NQC is measured by multiplying nameplate capacity by a resource-specific Electric Load Carrying Capability ("ELCC"), expressed as a percentage of nameplate capacity. NQCs for renewables can be under 10 percent of nameplate capacity.

The RA benefits provided by a resource is equal to its NQC multiplied by the value of RA in $/MW/year. The value of RA is a function of the balance between the available supply and the aggregate demand on the system and can vary from year-to-year. In this study, we estimate RA benefits using the aggregated RA contract prices from the latest CPUC resource adequacy report dated March 2021.[112]

The weighted average price (2019$) for System Resource Adequacy was calculated at $41,250/MW-year and the weighted average price (2019$) for Import Resource Adequacy was calculated at $21,960/MW-year. The estimated RA benefits for each applicable Portfolio in 2027 and 2035 are shown in Table 70 and Table 71 below.

[112] *2019 Resource Adequacy Report*, CPUC Staff, March 2021. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/2019rareport-1.pdf

Table 70: 2027 Resource Adequacy Benefits

Portfolio	Total Generation Capacity (kW)	Total Transmission Capacity (kW)	Total RA Benefit - Generation (2019$)	Total RA Benefit - Transmission (2019$)	Total Resource Adequacy Benefit (2019$)
Portfolio 3	4,334	0	$179,947,680	$0.0	**$179,948,000**
Portfolio 5a	737	0	$30,591,106	$0.0	**$30,591,000**
Portfolio 5b	2,535	0	$105,269,393	$0.0	**$105,269,000**
Portfolio 5c	3,433	0	$142,518,563	$0.0	**$142,519,000**

Table 71: 2035 Resource Adequacy Benefits

Portfolio	Total Generation Capacity (kW)	Total Transmission Capacity (kW)	Total RA Benefit - Generation (2019$)	Total RA Benefit - Transmission (2019$)	Total Resource Adequacy Benefit (2019$)
Portfolio 3	3,922	0	$162,841,440	$0.0	**$162,841,000**
Portfolio 4a	0	2,875	$0	$63,135,000.0	**$63,135,000**
Portfolio 4b	0	2,000	$0	$43,920,000.0	**$43,920,000**
Portfolio 5d	0	710	$0	$15,594,345.0	**$15,594,000**
Portfolio 5e	0	1,794	$0	$39,396,240.0	**$39,396,000**
Portfolio 5f	0	2,335	$0	$51,265,620.0	**$51,266,000**