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Phase 3 Overview

Phase 3 Workshop

FTI and GSC

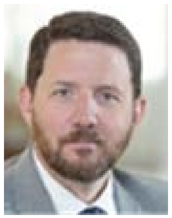
Phase 3 of the Aliso Canyon OII is intended to build upon the results of Phase 2 and ultimately take the next steps towards evaluating options for an Aliso Canyon retirement. The Project Team selected for the engagement and working under the direction of the CPUC Energy Division includes experts from two firms, FTI and GSC, who specialize in gas markets, power markets, and infrastructure investment. Our primary objective is to identify and analyze options to invest in new infrastructure that could facilitate the retirement of the Aliso Canyon facility.

Gas Supply Consulting, Inc.: Lead experts for gas market analysis including hydraulic simulation, deliverability analyses, and infrastructure options

FTI Consulting: Lead for power markets analysis including electric market simulation, economic analysis of infrastructure investments, and regulatory gaps analysis

Project team

ENGAGEMENT LEADS



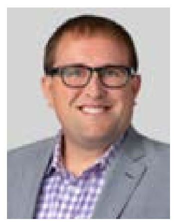
Matthew DeCourcey
Managing Director, FTI

Tim Sexton
President, GSC

Venki Venkateshwara, PhD
Managing Director, FTI

Mitch DeRubis
Director, FTI

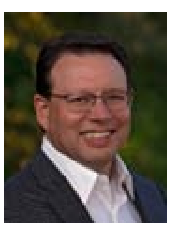
Anthony Broussard
Consultant/Engineer, GSC



Ken Sosnick
Managing Director, FTI

Ken Ditzel
Managing Director, FTI

Kim Decell
Director, GSC



Todd Bohan, PhD
Director, FTI

Drew Cayton
Director, FTI

Ian McGinnis
Consultant, FTI

Victoria Lorvig
Consultant, FTI

Scope

Our assignment builds on the work completed in Phase 2 and is defined in *the Assigned Commissioner's Phase 3 Scoping Memo and Ruling*, issued in I.17-02-002 in December 2019. At the highest level of abstraction, Phase 3 is designed to answer the following two questions:

What infrastructure investments are required to retire Aliso Canyon?

- "How can the services presently provided by the Aliso Canyon field be met if the field were to be eliminated?"
- Solutions can include "demand reduction and demand management programs….replacement of gas transmission pipelines or the construction of new gas transmission pipelines; and replacement electric generation resources that are carbon neutral or act to integrate renewable energy."

What are the costs and benefits of the available options?

- Elements upon which solutions will be assessed include "…the cost of replacement technology(ies) within a utility system, any potential impact on commodity costs…the timelines to develop and implement the technology(ies), and regulatory constraints."

Phase 3 is **solutions-oriented** by design and incorporates both **operational** and **economic** analyses

Analytical approach

Operational Analysis

Simulate the operation of the electric and gas systems on an hourly basis under peak day conditions to determine how reliant it is on Aliso Canyon. Based on those results, specify multiple packages of investments that would allow for the facility to retire without impacting reliability.

Benefits Analysis

Conduct long-run economic analysis to determine which of the investment options is most beneficial and/or least expensive from ratepayers' perspective.

Production Cost Modeling → **Hydraulic Modeling** → **Identify Investments**

WORKSTREAM 1

Economic Modeling → **Financial Modeling**

WORKSTREAM 2

Today's focus is on Workstream 1, which centers on analyses of the gas system's reliance on Aliso Canyon for each of 2027 and 2035 and the calculation of the generation that could not be served if Aliso is retired and no infrastructure investments are made. Later, in Workstream 2, we will test the net economic benefits several packages of investments that would facilitate the facility's retirement without adverse impacts to reliability.

Phase 3 Overview

Workstream 1 walkthrough

1	Run electric simulation with no gas constraints for a 1-in-10 winter peak day to determine how much gas is burned hour by hour to meet system demands
2	Run hydraulic simulation with Aliso removed to determine how much gas the system can deliver to EG hour by hour
3	Calculate hourly shortfall of gas deliveries and convert to electric output, which defines the generation shortfall that arises when Aliso is retired
4	Define portfolios of infrastructure investments that could facilitate an Aliso retirement based on the generation shortfall

WORKSTREAM 2

Specs of the infrastructure investments for testing from an economic perspective if the in Workstream 2 is ultimately the primary output

Key inputs

The Project Team chose **2027** and **2035** for analysis in order to conform to the Scoping Order, sampling distinct time periods, and generating actionable results.

The *Unified RA and IRP Modeling Datasets 2019* data that were used in Phase 2 serve as the starting point for all key inputs. Where applicable, adjustments were made for "known and measurable" changes, with all such changes documented in the datasets posted online.

Phase 2 Inputs

- Resources
- System topologies
- Peak demand and load shapes
- Renewable output

Adjustments

- Resources known to have been commercialized
- New demand forecast in updated CGR

Phase 3 Inputs

- Fully reconcilable to Phase 2 inputs
- Posted worksheets show adjustments where they were made

Unified Datasets available at https://www.cpuc.ca.gov/General.aspx?id=6442461894

Why 2027 and 2035?

From the I.17-02-002 Scoping Memo:

"The purpose of Phase 3 is to engage parties and an expert consultant in developing scenarios to examine resources and infrastructure, including renewable and low-carbon generation, energy efficiency, electric storage, demand response, and new gas transmission pipelines, that could be implemented to entirely replace the Aliso Canyon field within two different planning horizons: 2027 and 2045."

- We interpret this direction to mean that analyses must assume the facility's retirement *prior to* 2027 and 2045, respectively, but not necessarily on those dates

Our objective is to meaningfully support decision-making, subject to any constraints imposed by Commission mandates. From that perspective, two priorities arise:

1. Select dates that are either actionable or that provide useful insight
2. Sample different and distinct periods

Selected dynamics we have not attempted to capture

Changes to RA and system planning

While the modeling team recognizes that changes to system planning may be possible given recent reliability outcomes, we have not embedded any changes to expected reserve margins, resource mixes, or other factors into our planning. With the exception of the "known and measurable" changes, the resource list used in the simulations aligns with those utilized in Phase 2.

EV buildout

The modeling team is aware of the September 2020 Executive Order regarding zero-emission vehicles and its 2035 mandate. In part because limited information is available on the potential impact of the Order, and in part because of a desire to limit deviations from Phase 2 assumptions, we have chosen not to attempt to incorporate impacts in the simulations.

SCG system modernization

Modernization of the SCG's Northern Zone could increase the system's ability to receive gas from interstate systems at Needles, Topock, and Kramer Junction. Improvements elsewhere could also increase deliverability. Because regulatory approval of such modernizations are uncertain, we have excluded them from the base assumptions, but they could be considered among the solutions discussed later.

While we are aware that there could be changes to the gas and electric system which could materially affect our results, we are not currently embedding changes to reflect these factors for a variety of reasons, including the potential for effects to be small or negligible, current lack of detailed information regarding changes, and preferences for consistency with Phase 2 inputs.

Today's objectives

Reporting	Phase 3 approach and objectives Workstream 1 modeling ▪ PCM and hydraulic modeling methods and inputs ▪ Key uncertainties ▪ Results
Planning	Proposed investment portfolios to analyze in Workstream 2 Next steps Timelines and milestones
Engagement	Targeted input ▪ Key uncertainties, proposed portfolios Multiple opportunities for engagement going forward ▪ Written comments in I.17-02-002, upcoming meetings ▪ Publicly hosted opportunities for Q&A to be facilitated by the CPUC Energy Division

Remaining sessions

Power market simulation

Mitch DeRubis, *FTI*

- PLEXOS inputs and reconciliation to Phase 2 input sets
- Key uncertainties
- Results and comparison to Phase 2 output

Gas market simulation

Tim Sexton, *GSC*

- Gregg inputs, calibration, reconciliation with SCG model
- Key uncertainties
- Results and plant-level curtailment

Next steps

Matt DeCourcey, *FTI*

- Translating gas deliverability to a MW shortfall
- Proposed solutions for analysis
- Looking ahead to Workstream #2

Q&A

Questions and/or comments on any of the materials presented today

Questions?

???

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Preliminary Production Cost Modeling Results

Phase 3 Workshop

Production Cost Modeling Software Platform

1	Energy Exemplar PLEXOS Market Simulation Software
2	Co-optimized MIP unit commitment and economic dispatch
3	Extensive resource modeling: including detailed CCGT and storages
4	User-defined constraints; hourly and sub-hourly simulation
5	Website: https://energyexemplar.com/solutions/plexos/

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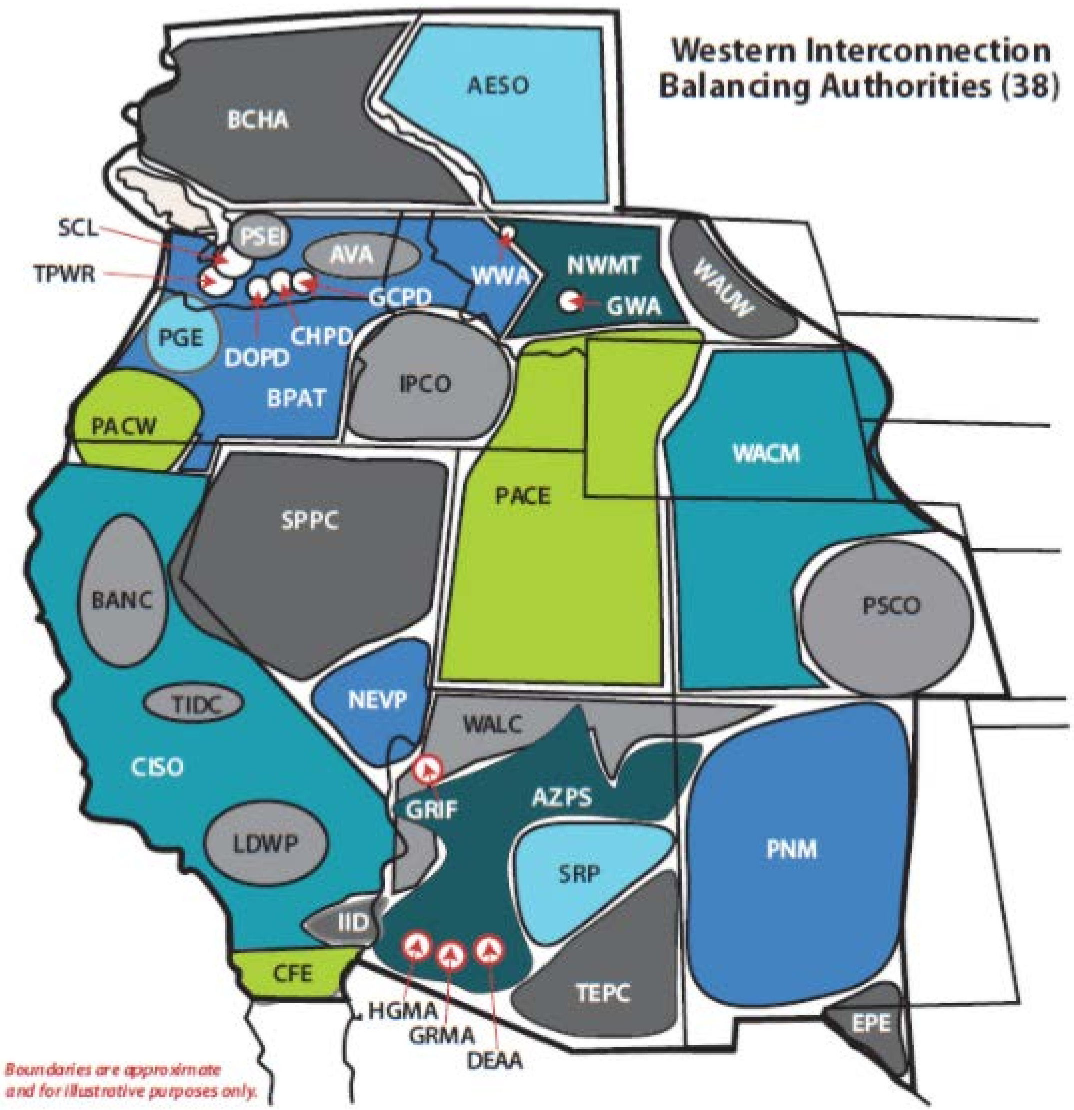
PCM Model Illustration - WECC Balancing Authority in PLEXOS



Source: NREL

Energy Exemplar's PLEXOS WECC Zonal model represents the WECC system as 34 zones:

- Some small balancing authorities aggregated
- CAISO represented by SCE, SDG&E, and PG&E zones

Operational vs. economic analysis

The analyses undertaken in Workstream 1 using the PCM are centered on operational rather than economic outcomes, which creates important differences in model setup.

PLEXOS is run to capture the operation of the CA gas-fired fleet. The only relevant output from this step of the analysis is the hourly gas burn for each of the 235 units in the study footprint. Simulations are calibrated based on the CGR gas burn forecast (for EG).

	Operational Analysis ***Workstream 1***	**Economic Analysis** ***Workstream 2***
Time step	Critical period	Multi-year
Primary output	Gas burns	Market prices
System production costs	No	Yes
GHG emissions and costs	No	Yes
Gas market impacts	No	Yes
Calibration targets*	▪ CGR peak gas burns ▪ Historic peak period imports	▪ Historic and future SHRs ▪ Annual and seasonal generation trends

** Variables and indicative targets lists are indicative for purposes of discussion*

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Case development

ASSUMPTIONS

Aliso Canyon storage in service

- Implied assumption

Peak day EG gas burn from 2020 CGR

Heavy reliance on electric imports during peak demand conditions

INPUTS

Phase 2 inputs

- Load shaping, transmission, generation, etc.

Omit economic variables

Adjustments for “known and measurable” changes

CALIBRATION

Target peak day gas burns and expected import results

- Maintenance for non-gas resources
- Peak hour load shaping

Calibration changes generally small

Unit gas burns

Input to hydraulic analysis

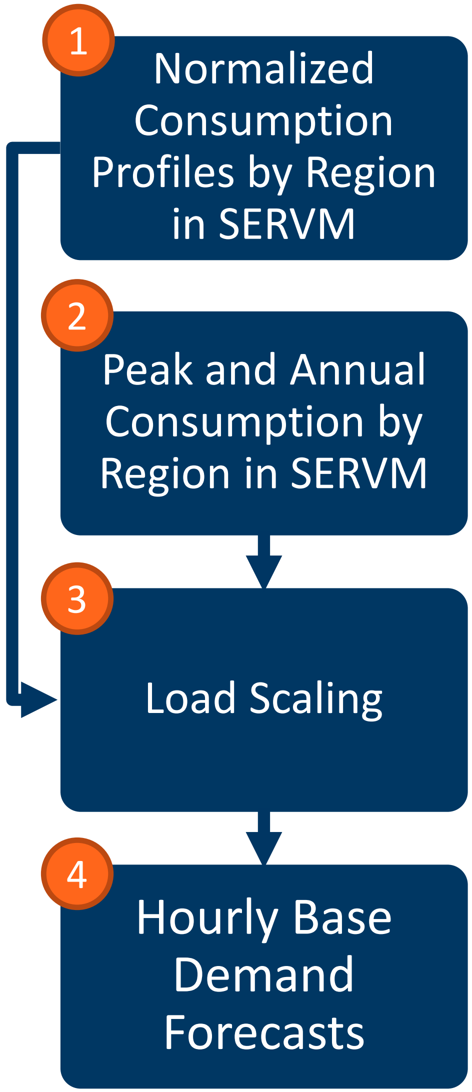
Cases include assumptions not directly embedded in the simulation, including “known” peak day gas burns from EG from the 2020 California Gas Report and continued heavy reliance on imports during peak conditions that are consistent with historical observations. Continued operation of Aliso Canyon is an implied assumption. Simulations are set up using the Unified Datasets (Phase 2 inputs), adjusted for “known and measurable” changes - mostly new projects that have been developed since the Datasets were compiled. Calibration fine tunes results to target assumptions by changing the most uncertain variables – maintenance and peak day load shapes – while holding other variables constant. Unit gas burns are the only meaningful output.

Key inputs overview

Input	Source	Adjustments/Variances
Generation/batteries	Resources based on the SERVM/RESOLVE inputs ▪ RSP Total Resources List, REC contract assumptions, renewable gen profiles, etc. ▪ Matches based on EIA codes, research by FTI ▪ Aggregation of renewables and small units	New facilities developed since Phase 2 *ex.* Moss Landing battery facility Use of load-following algorithm for hydro
Demand	Peak demand forecast used in SERVM (based on the CEC 2018 IEPR) Normalized load profiles Demand modifier profiles	Scaled to achieve 1-in-10 modeling criteria Peak day load shapes adjusted in calibration process
Transmission	SERVM/RESOLVE inputs ▪ BAA/Region mapping ▪ Regional transmission limits	No system configuration adjustments

Datasets to be provided will allow for full reconciliation between model inputs – including all adjustments and variances – and the SERVM/RESOLVE model inputs used in Phase 2

Load forecasting – base demand forecast



Selection of Individual Yearly Consumption Profile:

Aggregate SDGE + SCE load profiles, and select weather year based on 1:10 Peak Winter Load Day

Annual Peak Load (MW) & Energy (GWh):

2018 – 2030, as reported

2031 – 2035, extrapolation based on 5-Year CAGR by region

Apply Peak Load & Total Energy to Consumption Profile:

Procedure applied as outlined in the "Guidance for Production Cost Modeling and Network Reliability Studies" document

Output:

Hourly base demand forecasts for each region, 2018 – 2035

Load forecasting – demand side modifiers

5. Demand Side Modifier Profiles in SERVM
6. Annual IEPR Demand Modifier Forecasts
7. Scaling
8. Hourly Demand Side Modifiers Forecasts

Hourly profiles by region, by year, by type:

- 2018 – 2030, as reported
- 2031 – 2035, repeated 2030 shapes

Annual “CAPMAX” (MW):

- 2018 – 2030, as reported
- 2031 – 2035, extrapolation based on 5-year CAGR by region, by type

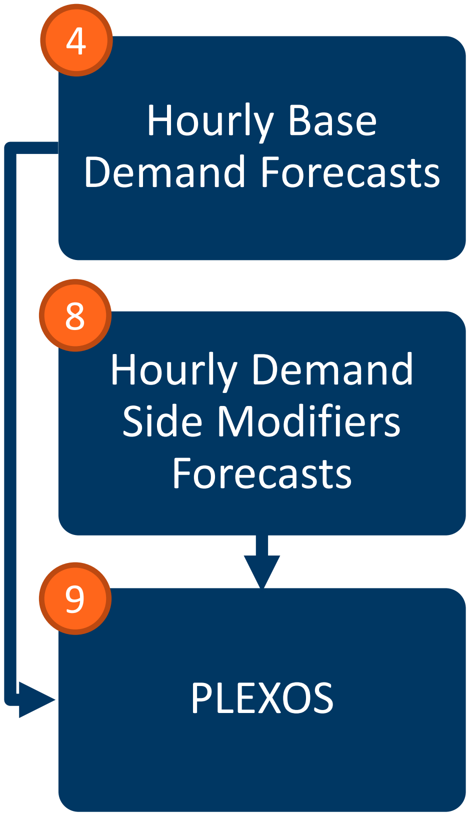
Apply Peak Load & Total Energy to Consumption Profile:

- Procedure applied as outlined in the “Guidance for Production Cost Modeling and Network Reliability Studies” document

Output:

- Hourly load-modifying demand forecasts for each region, 2018 – 2035

Load forecasting – addition and input to PLEXOS



Output from previous step 4:

Hourly base demand forecasts for each region, 2018 – 2035

Output from previous step 8:

Hourly load-modifying demand forecasts for each region, 2018 – 2035

Multi-band Load Forecast in PLEXOS:

The base demand and demand side modifier outputs are input into PLEXOS using the multi-band functionality (i.e., they are added together by PLEXOS)

Transmission flow limits & hurdle rates

Transmission Flow Limits

- Implemented transmission flow limits on region to region flows as represented in the 11-6-19 "Transmission Flow Limits and Hurdle Rates in SERVM" document
- Lines are implemented with "Max Flow" and "Min Flow" properties setting the region A -> B, and B -> limits
- All lines connecting to CAISO regions are aggregated and an interface limit is imposed upon them
  - The import limit is 11,600 MW consistent with the Phase 2 assumptions
  - For exports, we analyzed EIA-930 interchange data to estimate the historical simultaneous export limit from CAISO

Hurdle Rates

- Hurdle rates are consistent with Phase 2 assumptions
  - Implemented using the "NoCarbonAdder" entries
  - Then, applied an adder to each line importing power into California using CARB-assigned emission factors applied to the CEC's 2018 IEPR low carbon price forecast

Baseline generator units

PLEXOS –
EIA 860 (2020), Energy Exemplar & FTI Research

SERVM –
TEPPC 2026 Common Case, CAISO, RPS, Other

Advantages:
- Unit-specific operating parameters
- Updated online/retirement dates, cancellations

Disadvantages:
- Does not contain a long-term build out similar to the TEPPC Common Case

Units matched on:
- Name of plant / Unit
- Maximum Capacity
- Region
- Technology
- Online Date
- Retirement Date
- CAISO Master Generating Capabilities List

Additional Considerations:
- Unit aggregation by PLEXOS/SERVM
- SNL/ABB Research

Advantages:
- Contains a long-term build out of generation resources in WECC
- Individual unit-level operating characteristics not available for all generators

Disadvantages:
- TEPPC Common Case is several years old

Summary of generator reconciliation

	WECC		California	
	MW	% of total capacity	*MW*	% of total capacity
Capacity:	291,255	100%	84,530	100%
Initial Units Matched:	267,708	92%	80,199	95%
Cancelled / Delayed / Postponed Projects:	6,459	2%	1,005	1%
Fictional Resources:	1,320	0%	200	0%
Other exclusions:	3,991	1%	398	0%
Wind/Solar/Hydro Aggregations:	10,012	3%	2,345	3%
Remaining Aggregation:	1,765	1%	383	0%

Updates to Phase 2 datasets

Criteria for updating Phase 2 datasets based on “known and measurable” changes:

- SERVM/RESOLVE baseline generic battery storage as aggregate batteries with yearly changes in capacity by region
- Added existing batteries not accounted for in SERVM/RESOLVE
  - Subtracted from the RESOLVE capacity expansion battery storage by region to avoid double-counting planned projects
- Added RESOLVE selected capacity expansion units by year and zone, as well as demand response resources
  - Interpolated builds between 2025 and 2030
  - Extrapolated builds from 2030 to 2035
- Batteries in advanced stages of development as classified by S&P Global Market Intelligence
- Generating units in advanced stages of development as classified by S&P Global Market Intelligence

Phase 2 & FTI Comparison

		Phase II - RESOLVE 2026	Phase II - SERVM 2026	FTI 2027
Annual Generation	Battery Storage	(1,966)	(2,026)	(2,229)
GWh	BTM PV	30,631	30,556	33,546
	Gas	60,709	71,116	86,766
	Geothermal	9,888	10,348	6,673
	Hydro	22,996	25,391	23,466
	Nuclear	-	-	-
	Other	4,735	5,209	6,641
	PSH	(576)	(831)	(631)
	Utility-scale Solar PV	54,425	52,847	52,586
	Wind	25,980	18,830	26,744
	Total:	**208,788**	**213,466**	**235,791**
Capacity	Battery Storage	9,065	9,065	10,551
MW	BTM PV	17,437	16,156	18,553
	Coal	-	-	-
	Gas	26,940	26,914	26,916
	Geothermal	1,432	1,432	1,485
	Other	2,141	903	1,460
	PSH	2,572	2,573	2,319
	Utility-scale Solar PV	20,520	21,959	20,178
	Wind	10,196	10,193	10,251
	Total:	**81,238**	**80,130**	**81,162**

Variances between annual generation by gas-fired resources are not impactful since peak day results are the meaningful output from these simulations

Notable method adjustments

Transmission Import Limit

Phase 2 analysis includes 5,000 MW limit for demand at or above the 95th percentile

- The hours modeled in both 2027 and 2035 do not contain 95th percentile or higher load, compared to the summer months. Therefore, we used the normal SERVM 11,600 MW limit for the CAISO interface.

Hydro Output

Phase 2 modeling tools (SERVM/RESOLVE) essentially schedule hydro output

PLEXOS utilizes a load-following algorithm that better approximates actual operation of the resources

- Annual impacts are relatively small
- The load-following algorithm allows some flexibility in dispatching hydro resources to meet changing load

Model calibration

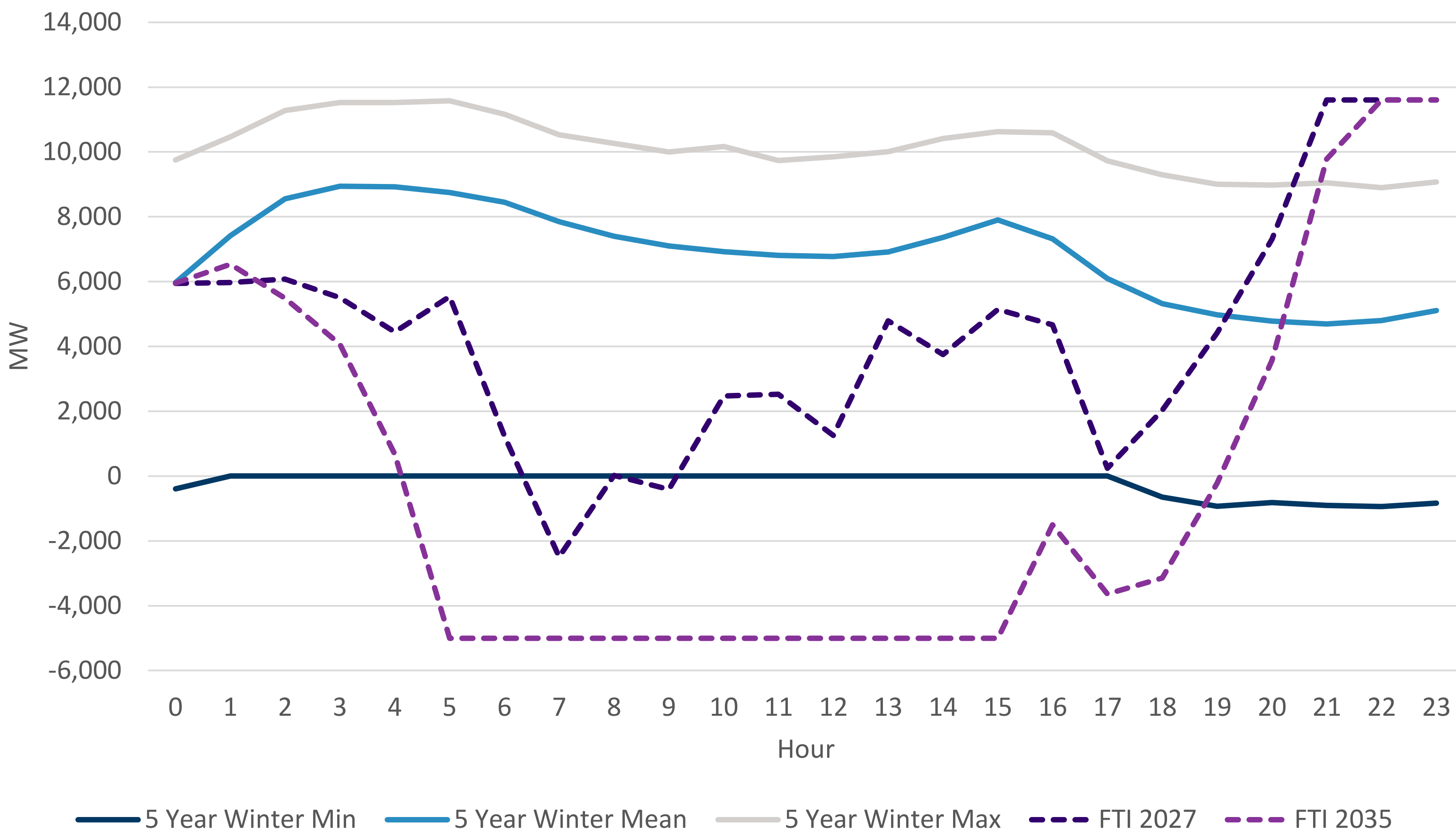
Multiple iterations were run with adjustments to selected uncertainties to calibrate results with the gas burn figures for SCE and SDGE shown in the current CGR serving is the primary target.

Variables adjusted for calibration included:

- Mid-merit unit outages
- Peak day load shaping

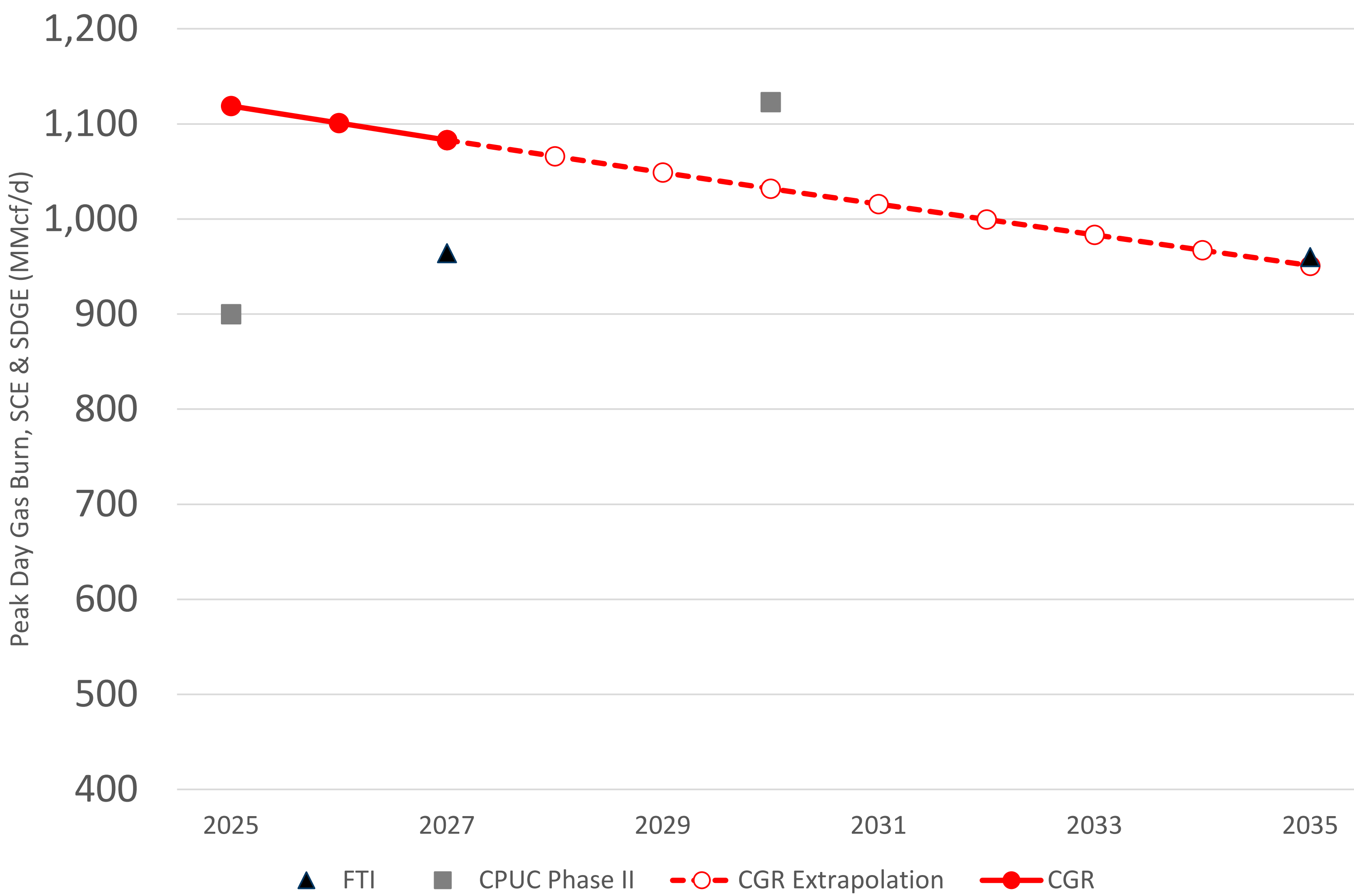
Adjustments were made in an iterative fashion and were generally minor. The same adjustments were applied for the two years modeled (2027 and 2035).

Peak day CAISO Interface Activity



Production Cost Modeling

Peak day gas burn comparison



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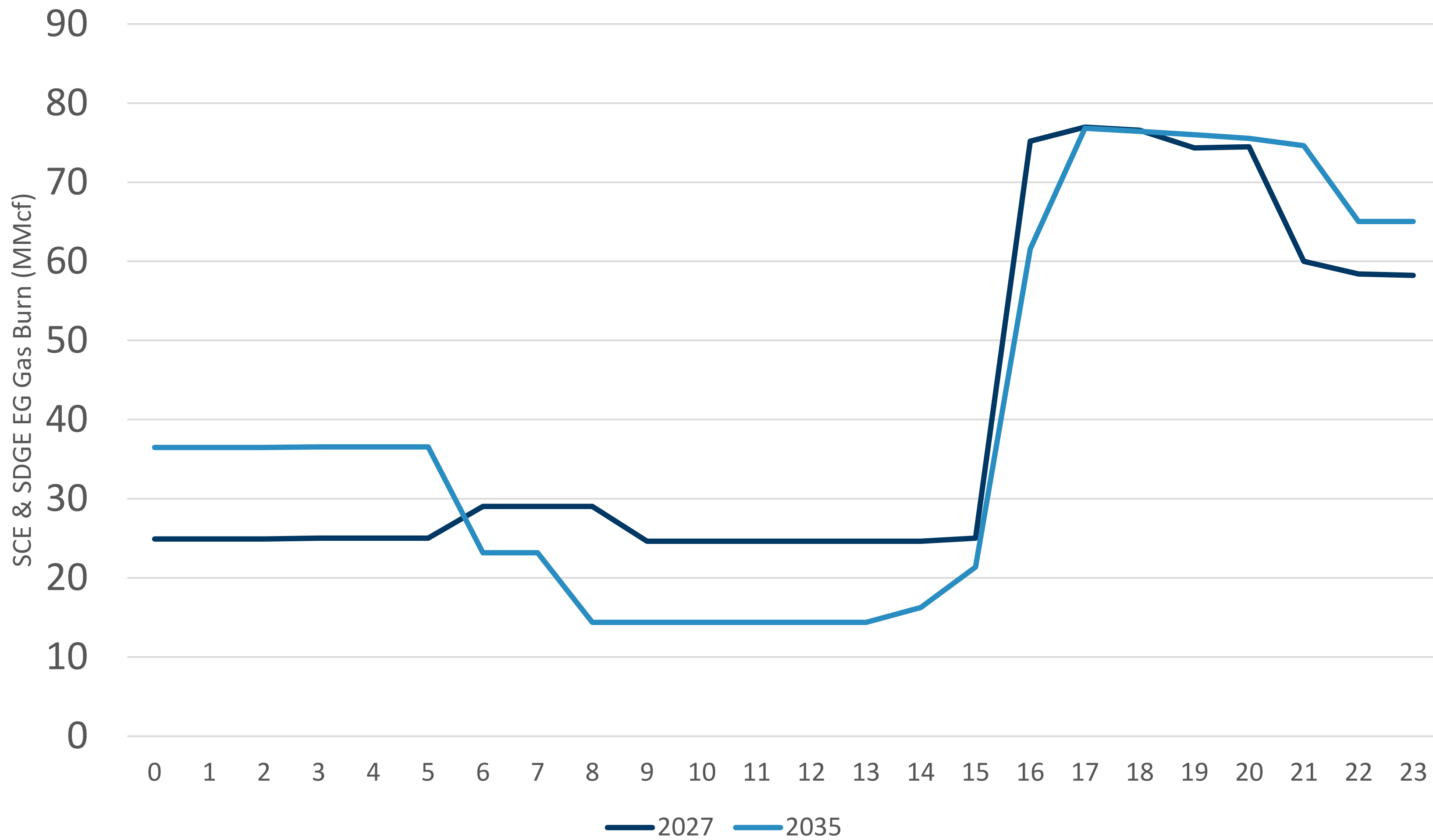
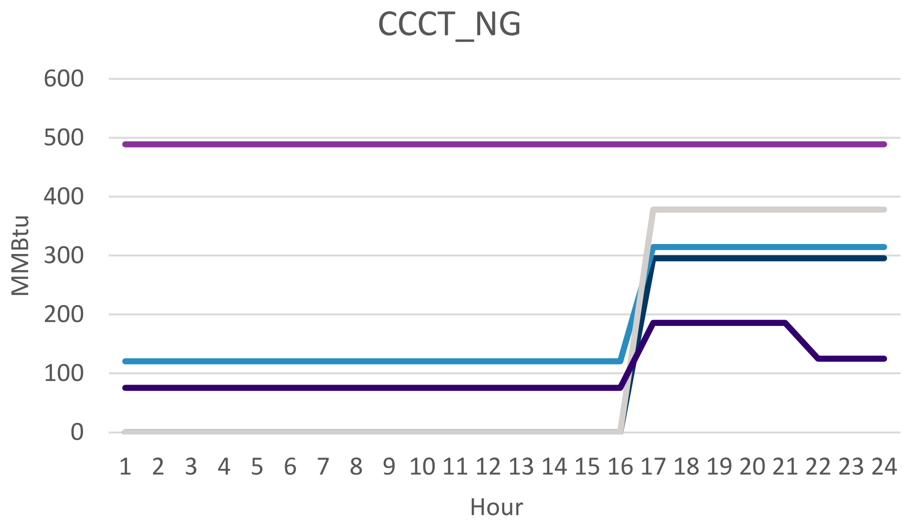
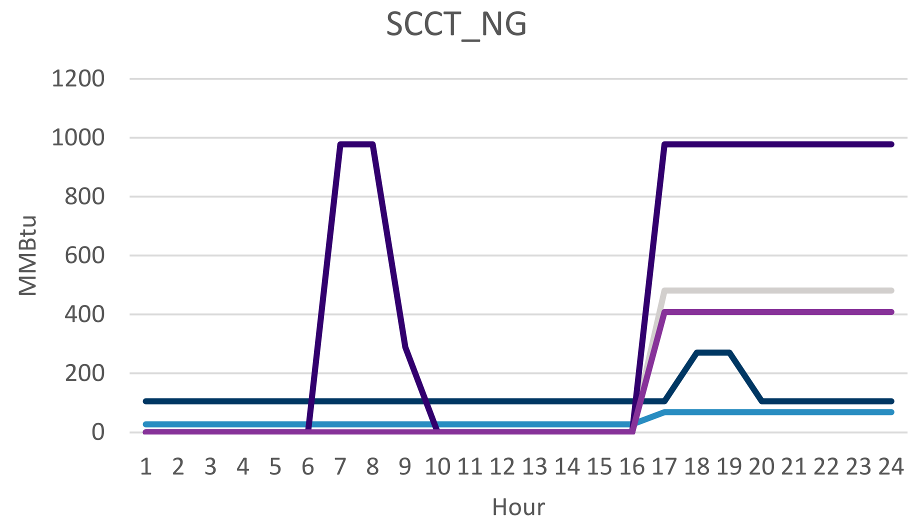
Peak Winter Gas Burn 24 Hour Profiles

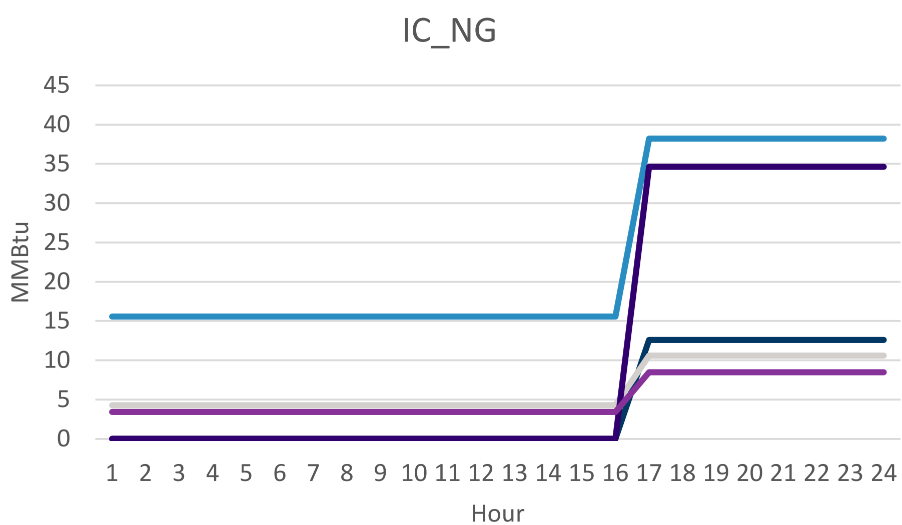


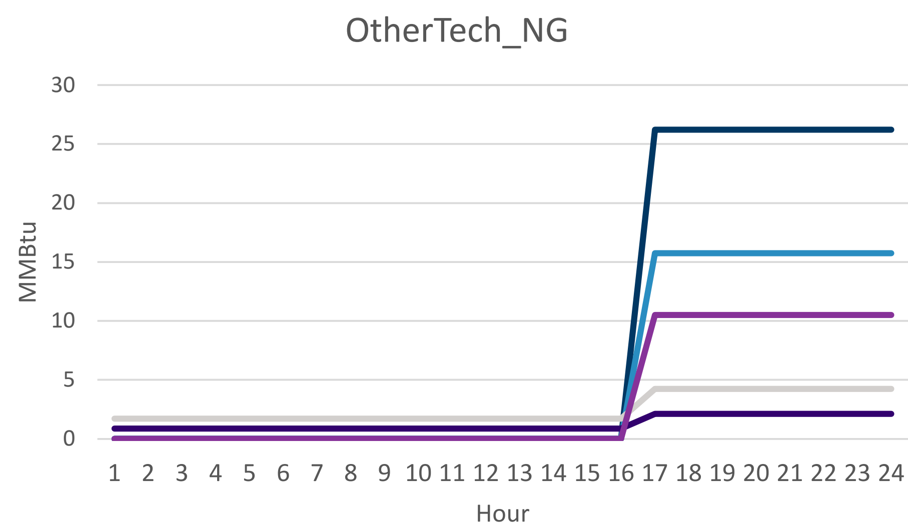
Production Cost Modeling

Sample plant-level gas burn, 2027









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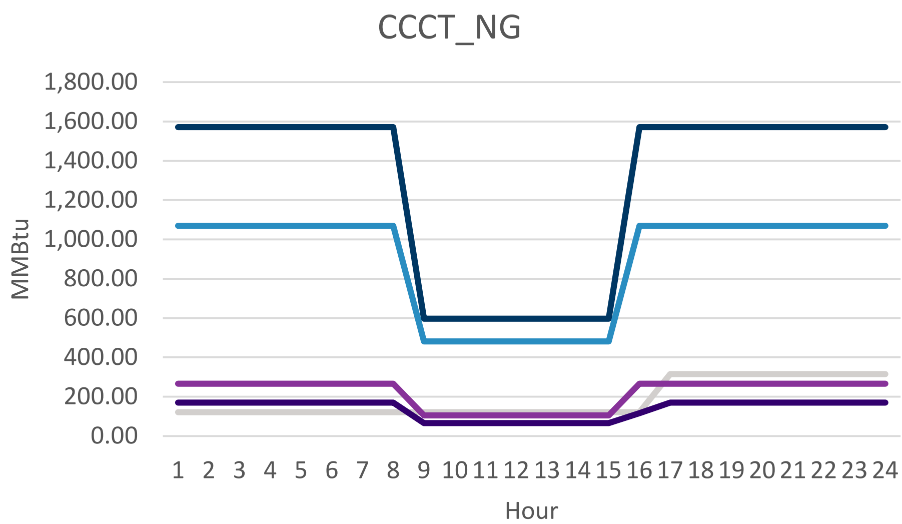
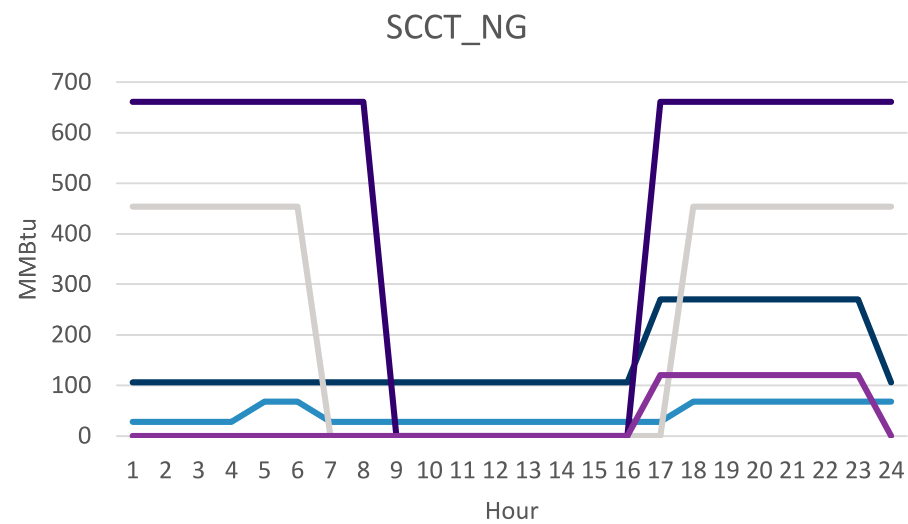
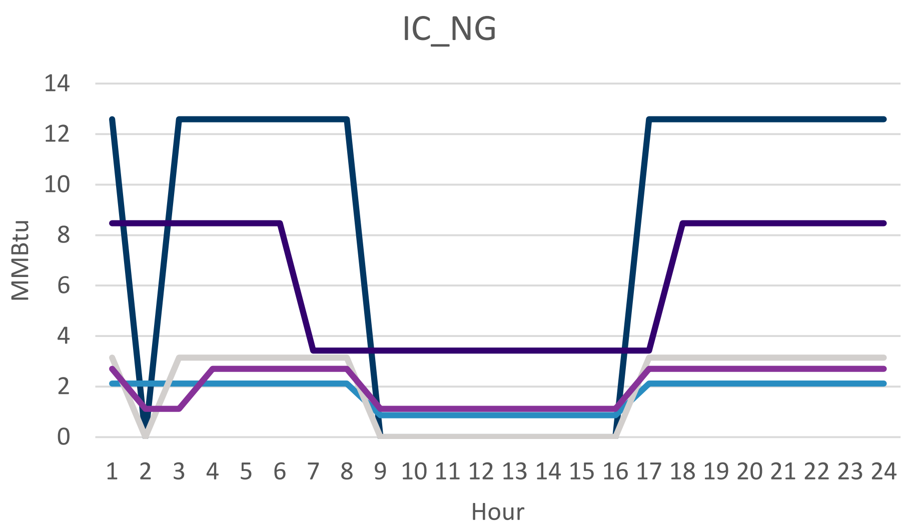
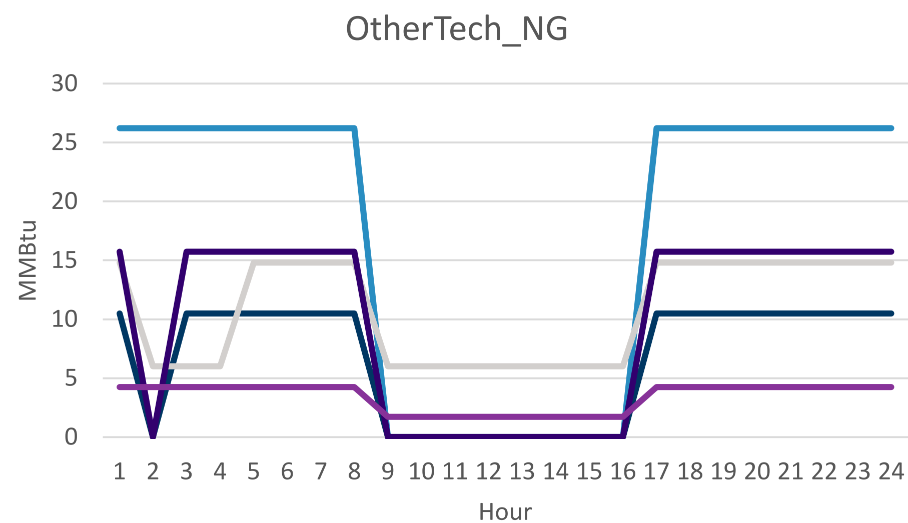
Sample plant-level gas burn, 2035









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Questions?

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Preliminary Hydraulic Modeling Results

Phase 3 Workshop

Gas Supply Consulting, Inc. – Background and Experience

GSC has extensive experience developing hydraulic models of existing pipelines, expansions to existing pipelines and/or proposed greenfield development pipeline systems throughout the US natural gas grid; and

GSC hydraulic models have been utilized to support both shipper (LDC, producer, etc.) positions and pipeline filings in numerous FERC proceedings.

In addition to hydraulic modeling work, GSC provides advisory services to numerous clients with respect to various operational, commercial and regulatory functions within the US natural gas market.

GSC Staff working on the Aliso Canyon OII Phase 3 Project include:

- Hydraulic Modeling / Gas Infrastructure / Gas Market Analysis
  - Tim Sexton, President – 30+ years of natural gas industry experience (25+ years at GSC)
  - Anthony Broussard, Consultant / Engineer – 10+ years of industry experience (≈ 3 years at GSC)
- Gas Infrastructure / Gas Market Analysis
  - Kim Decell – Director of Supply Services – 30+ years of industry experience (20+ years at GSC)

Hydraulic Model Background and Process

Hydraulic Model Background

- Independent, third party hydraulic model analysis
- Based upon CPUC Phase 2 Model
- Developed using Gregg Engineering NextGen Software
- Provides consistent results to CPUC Phase 2 model

Model Evaluations

- Model used to evaluate winter peak day base delivery capability absent Aliso Canyon
- To extent demand reductions are required, base models focus on reduction of EG demand component

Hydraulic Modeling Software Platform

1 **Gregg Engineering NextGen Hydraulic Modeling Software**

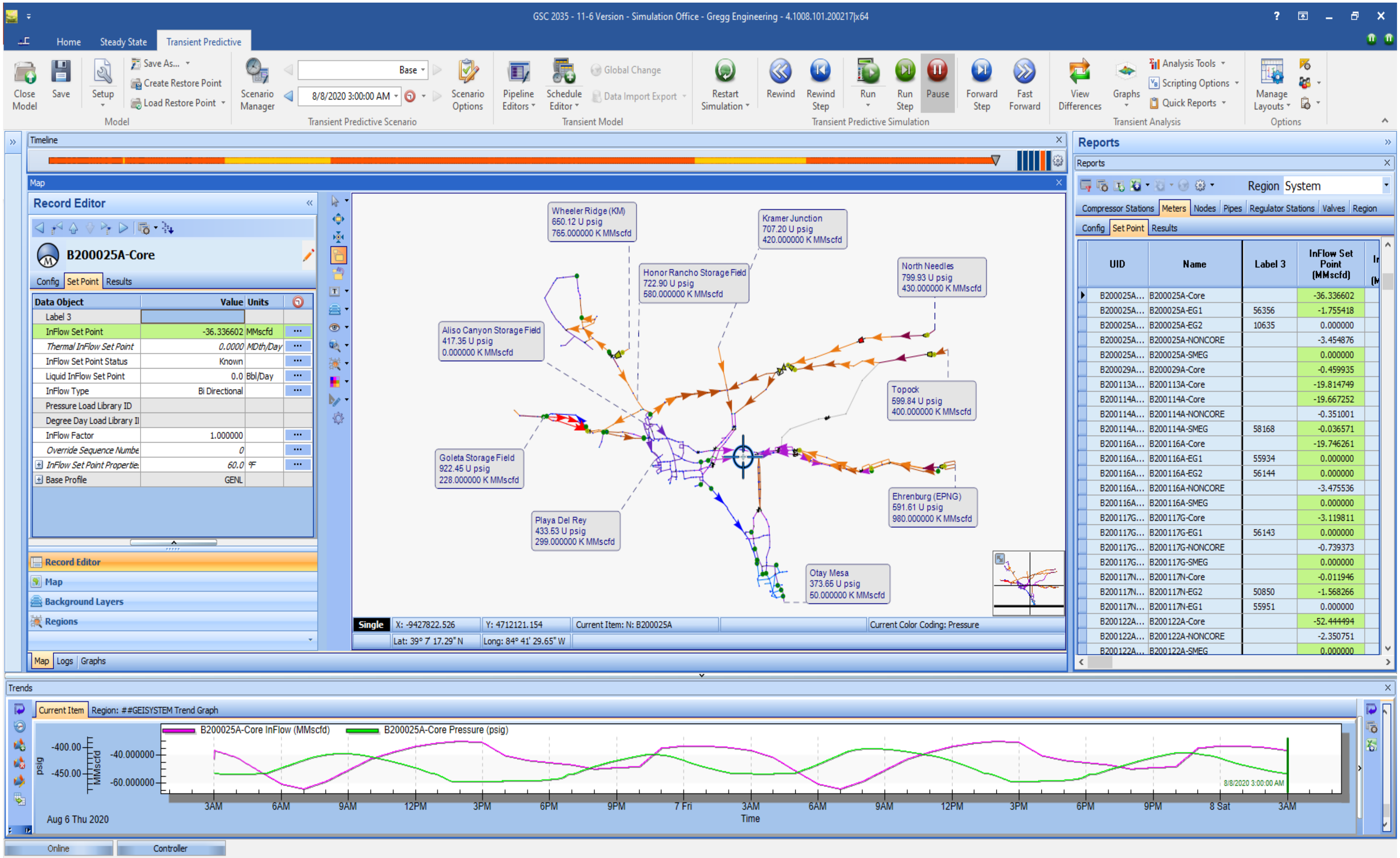
2 **Supports Steady State and Transient Simulations**

3 **Input Facility Data Based Upon CPUC Phase 2 Model**

4 **Used by Natural Gas and Liquids pipelines worldwide, including majority of US Interstate Pipelines**

5 **Website:**
https://www.greggeng.com/software-solutions/nextgen-simulation-suite/

Hydraulic Model Illustration – Gregg NextGen Software



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Base Case - Hydraulic Model Development Process

Step 1
CPUC Synergi Gas SIM 01 Hydraulic Model Converted from Synergi Gas to Gregg NextGen Software

Step 2
Verified / Adjusted Conversion for Consistency with CPUC Model
Facilities, CS / Regulator Settings, Gas Properties, Ground Temp, flow / HP equations

Step 3
Developed Steady State Model of SIM 01 (Midnight) Scenario.
Tuned against CPUC version for consistency in results

Step 4
Loaded SIM 01 (DR 3) Delivery Data and Hourly Profiles to create Transient Hydraulic Model.

Step 5
Created Updated 2027 and 2035 Hydraulic Models for use in Workstream 1 Evaluations

Hydraulic Model Tuning Process

Review CPUC Steady State Results

- Steady State Results of CPUC SIM 01 Analysis with demand at midnight
- Receipt and Delivery Quantities and Pressures
- Pressure Control Equipment (Regulators and Compressors)

Develop Replica Model of CPUC Results

- Supply and Delivery Quantities Identical to CPUC SIM 01 Midnight Model
- Receipt Pressures Set Equal to CPUC SIM 01 Midnight Model
- Compressor Discharge / Regulator Outlet Pressures set to CPUC Model

Tune Model

- Run Steady State Model to assess variances between results of CPUC Synergi Gas Model vs. Gregg NextGen Model
- Adjusted pipeline roughness in isolated area to match modeled results

Final Base "Tuned" Model

- Variance between average steady state delivery pressures in GSC- Gregg Model vs CPUC Synergi Gas Model is less than 1 psig across the system
- Largest single delivery pressure variance of less than 5 psig

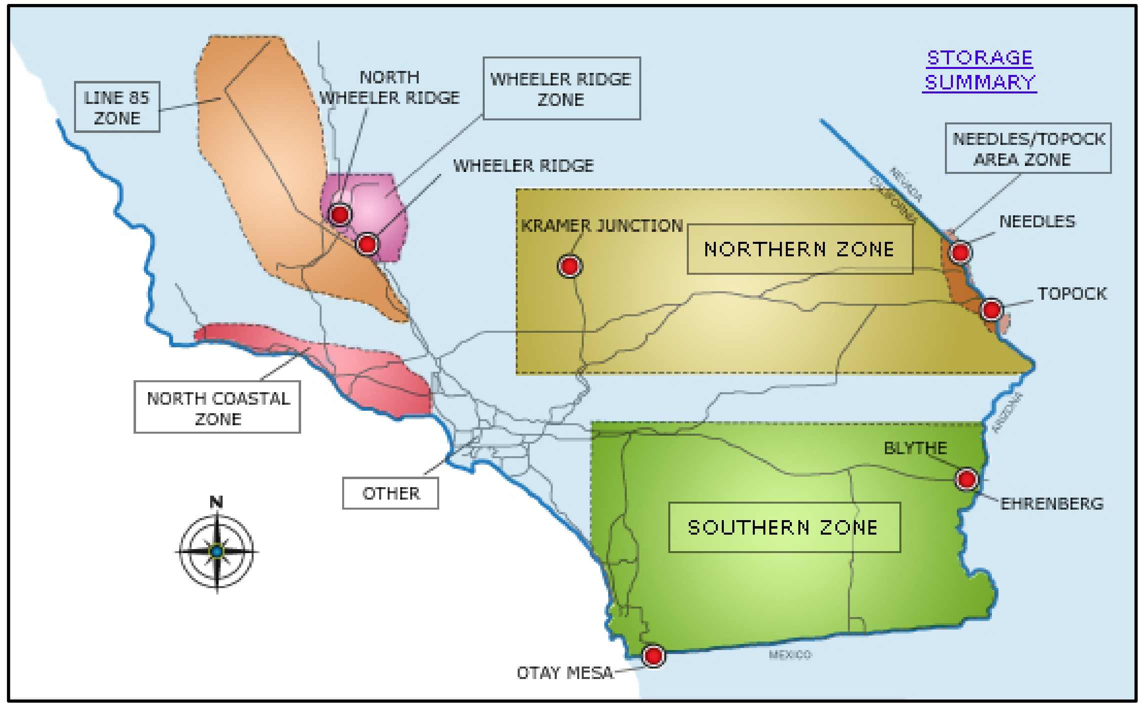
Hydraulic Modeling Process – Underlying Assumptions

Input	Base SIM 01 Replica Model	Adjustments/Variances in Final Model
Natural Gas Properties	Heat Content: 1,000 Btu/cf Specific Gravity: 0.60 Gas Flowing Temperature: 65° F Ambient (Ground) Temperature: 60° F	Gas Temperature Set at 65° F at receipt points Temp Tracking Enabled /Ground Temp at 60° F Heat Content (1,033.6 Btu/cf) handled in EG demand calculations / Model at 1,000 Btu/cf
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 Sources in 2027 and 2035 Models

- Pipeline Supply Sources Consistent with Supply Sourcing in CPUC – SIM 05 Analysis
  - 85% Pipeline Utilization in Northern and Southern Zones and 100% in Wheeler Ridge Zone

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 Withdrawal Supply Sources

[redacted]

NG Demand in Hydraulic Analysis for 2027 and 2035 Scenarios

Demand Assumptions (MMcfd)	CPUC Phase 2 Simulations			Phase 3 Base Case (Total Demand)		
Demand Category	**SIM 01 - 2020**	**SIM 03 - 2025**	**SIM 05 - 2030**	**Phase 3 - 2027**	**Phase 3 - 2035**	**Phase 3 Data Source**
Core	3,285	3,171	3,034	3,101	2,987	1/
Non-Elec Gen Non-Core	654	689	665	670	653	2/
Elec Gen	1,048	900	1,123	964	960	
Total	**4,987**	**4,760**	**4,821**	**4,735**	**4,600**	
Electric Generation Demand Breakout						
FTI-PLEXOS				840	839	3/
EOR Electric				52	50	4/
Refinery Electric				72	71	4/
Total				**964**	**960**	

1/ Core Demand ("1 in 10") for SoCal Gas and SDG&E per each company's 2020 California Gas Report Redacted Workpapers. Core Demand for "Other Core" based upon California Gas Report data for 2026 escalated to 2027 and 2030 based upon weighted rate of change of SoCal Gas and SDGE Core Demand.

2/ Non-Elec Gen Non-Core based upon California Gas Report Data for 2026 adjusted to 2027 and 2030 based upon the rate of change in core demand.

3/ FTI-PLEXOS Model Demand (Facilities Connected to SoCal Gas System).

4/ EOR Electric and Refinery Electric based upon SIM 01 (DR 3) EOR and Refinery demand as adjusted from 2020 to 2027 and 2035 based upon "Non-Core" rate of change for Refinery and "Core" rate of change for EOR during these same years.

Hourly Demand Profiles Utilized

- Core Demand Profiles Consistent with SoCalGas Core Profiles
- Non-Core Commercial and Industrial Profiles Consistent with SoCalGas Profiles
- EG Profiles as developed by FTI using PLEXOS model for years 2027 and 2035

Hydraulic Model Results – Demand Less Required EG Reductions

Model Results *(MMcfd)*	Phase 3 Simulations 2027	Phase 3 Simulations 2034
Demand Category		
Core	3,101	2,987
Non-Elec Gen Non-Core	670	653
Elec Gen	964	960
Total	**4,735**	**4,600**
EG Demand Breakout		
FTI-PLEXOS	840	839
EOR Electric	52	50
Refinery Electric	72	71
Total	**964**	**960**
EG Demand Reduction to Balance Model		
Base Requirements (above)	4,735	4,600
(Demand Reduction (EG))	(434)	(318)
Total Served in Hydraulic Model	**4,301**	**4,284**

- EG demand reductions undertaken at least efficient (highest heat rate) generation facilities first.
- Natural Gas Delivery Reductions equate to approximately 56,000 MWh and 33,000 MWh of reduced winter peak day gas generation in 2027 and 2035, respectively.

Hydraulic Model (2027) – Hourly Supply / Demand / Line Pack

[redacted]

Hydraulic Model (2027) – Honor Rancho Storage Withdrawals

[redacted]

FTI CONSULTING

Gas Supply Consulting, Inc.

Subsystem Line Pack: Hydraulic Model (2027)

[redacted]

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Hydraulic Model (2035) – Hourly Supply / Demand / Line Pack

[redacted]

Hydraulic Model (2035) – Honor Rancho Storage Withdrawals

[redacted]

Subsystem Line Pack: Hydraulic Model (2035)

[redacted]

FTI CONSULTING

GSC Gas Supply Consulting, Inc.

Hydraulic Model Results Summary

Delivery Quantities

- All Core and Non-Core (non EG) deliveries maintained
- EG deliveries reduced by 434 MMcfd and 318 MMcfd in 2027 and 2035 models to accommodate potential impact of removing Aliso Canyon from service

Pressures

- System Pressures maintained below MAOP
- Delivery Pressures maintained above minimum allowable operating pressures with a few isolated variances in San Joaquin Valley
- Isolated San Joaquin Valley pressures fell below minimum allowable operating pressure by 20 psig or less.

Line Pack

- Line Pack Recovers Over Twenty-Four-Hour Period

Supplies

- Honor Rancho Storage and Line Pack Successfully utilized to Balance Demand Variations during the day
- All Other Pipeline and storage receipt points held constant at planned levels

Key Assumptions Underlying Study for Consideration

1	Storage Withdrawals Available at 90% Inventory Level
2	85% Pipeline Utilization in Northern and Southern Zones and 100% in Wheeler Ridge Zone (Current System Capacity)
3	Required Curtailments Made to Generation Demand
4	Honor Rancho Used to support in-day demand fluctuations
5	Core / Non-Core Gas Demand Source – California Gas Report

A key finding is that the removal of Aliso creates a gas delivery shortfall that translates to unserved electric energy. Solutions that will be considered that address the shortfall include development of non-gas-fired generation, gas demand reductions, or the development of new gas infrastructure that could include gas storage.

Questions?

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Next Steps

Phase 3 Workshop

Next Steps

Identifying investment packages

<u>Summary process</u>

- Analyze modeling results to determine deliverability shortfall
- Convert dth to MW (per hour), where applicable
- Specify investments to that would offset the shortfalls, whose economics will be analyzed later in Workstream 2

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Converting to a MW shortfall

Calculate gas burns using PCM

Inputs	Key output
Consistent with IRP projections, plus updates as described blow	Gas burns by unit by hour *(dth)*

Estimate deliverability with hydraulic model

Inputs	Key output
• Gas burns by unit by hour • System configuration • Non-EG demand	Shortfalls to EG by hour *(dth)*

Define the quantity of required infrastructure

Inputs	Key output
• Shortfalls to EG during the most critical hour • Constraints and preferences	Portfolios of investments that would offset delivery shortfalls *(MW)*

Following the calculation of the delivery shortfall, which is allocated entirely to EG, it is necessary to convert that shortfall to a MW value for each hour. This stop does include some uncertainty because it cannot be known with complete precision how delivery shortfalls will be allocated.

We have chosen to allocate the delivery shortfall based on unit efficiencies, which we measure via the heat rate for each unit, and assume that available gas would be allocated to the most efficient resources.

Alternative methods for allocating the modeled gas shortfall could include location (*e.g.* resources farthest from Aliso are curtailed), operational factors, or other variables. Choosing a method other than allocation by SHR would increase the amount of new infrastructure required to support Aliso Canyon's retirement.

Note that the shortfall is not delineated in MW for solutions based on supply- or demand-side gas infrastructure.

Calculated shortfall

The largest generation shortfall in any hour defines the most critical hour which, in turn, defines the quantity of new electric resources that would be required order to retire Aliso Canyon.

	Gas Delivery *(MMcf)*	Generation *(MW)*
2027	32.6	4,216
2035	24.2	2,600

Objectives and philosophies

Though they are designed to reflect commercial and operational realities in the market to the extent that doing so is practical, the portfolios of investments we have identified are intentionally broad. We expect that if the Commission were to choose to move forward with investments that facilitate Aliso's retirement, the most likely path is to direct utilities to procure resources in combinations that are ***guided*** by our results but not ***sharply defined*** by them. The utilities would conduct the types of cost-benefit analyses that are typical under such circumstances, from which would emerge an optimal mix of investments.

We are……

- Determining whether Aliso Canyon can be retired at an acceptable net cost
- Recognizing that there are uncertainties embedded in any forecast
- Identifying the types of investments that would be most likely to generate economic benefits for ratepayers
- Testing a wide range of options, from which we can impute useful insights

We are not……

- Attempting to guess at the specific mix of resources
- Making decisions that rely on perfect forecasting of precise costs or benefits
- Arbitrarily applying assumptions in ways that could create false precision issues
- Postulating speculative changes to technologies or dramatic changes to programs

While the tools we are using to analyze the investment options support more precise configurations, we have chosen this approach to reduce the risk that decisions are made based on false perceptions of precision.

Criteria for selecting investment portfolios

1. Reasonably reflect operational and commercial realities

Reliance on the interconnection queue provides useful insight into the technologies currently favored by developers while the IRP reflects detailed analyses of the costs and benefits of implementing new infrastructure

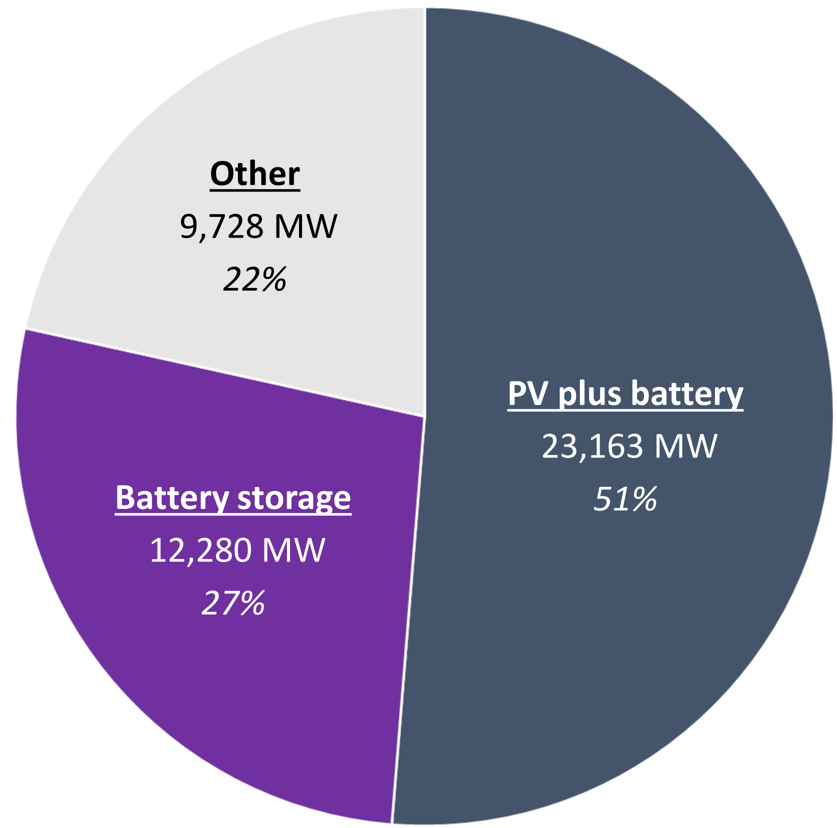
2. Conform to the Commission's orders

Indicate consideration of gas transmission, DR, and low-carbon generation

3. Focus on solutions that appear to be most plausible

Although we have not conducted feasibility studies, speculative technologies or very long-lead investments have been excluded

CAISO Interconnection Queue for SCE and SDGE *(Net MW)*



Considering strategies

Strategy	Description	Options include:	
Supply-side gas ***(dth)***	Build new infrastructure that provides for the amount of gas needed from Aliso Canyon during critical hours to maintain electric reliability	▪ Interstate pipelines ▪ Upgrades on the SCG system	▪ New gas storage or expansions
Supply-side electric ***(MW)***	Build non-gas-fired generation and/or storage to replace the output from the generators that can no longer be served once Aliso is retired	▪ Photovoltaic ▪ Wind	▪ Renewables + storage
Demand-side ***(dth or MW)***	Reduce demand in amounts sufficient to offset lost deliverability. Includes investments on both the gas and electric side.	▪ Gas or electric DR ▪ Gas or electric EE	▪ Building electrification

Multiple strategies exist to address shortfalls that arise when Aliso exits the market

Next Steps

Preliminary investment portfolios

Five investment portfolios will be tested in Workstream 2. We propose to define four of them now and to defer the definition of a fifth until analysis of the first four can be used to develop options most likely to add value. This approach is designed to move *towards* the design and analysis of investment options that are more optimized based on analytical market insights.

	Gas Transmission	Demand-side Gas	DR/Storage Mix	Queue Pro-Rata	TBD
Sector	**Gas**	**Gas**	**Electric**	**Electric**	**TBD**
Design	Investments in new infrastructure in CA and, possibly, on interstate systems to provide enough deliverability for the gas-fired fleet.	Combination DR, EE, and building electrification, scaled to meet requirement. Potential focus on C&I customers, based on past experience.	Mix of DR and storage based on proportions from the current IRP. Scale to meet requirement.	Mix of resources in amounts that are roughly consistent with the current CAISO interconnect queue for SCE and SDGE.	Portfolio to be defined by Project Team and CPUC following analysis of the first four options.
Rationale	CPUC orders suggest a preference to analyze investments in gas assets. May also address issues regarding imbalances and system flexibility.	Reflect policy focus on demand-side measures, test the potential to displace system investments that would be otherwise needed.	Realistic blend of new resources. The mix is optimized by the IRP analysis, which should result in competitive economics.	Best reflection of a "business as usual" outlook, the queue is a good indicator of current market preferences and expectations.	Deferring the configuration of the portfolio creates an opportunity to embed results from other cases into the design.

***Portfolios may change based on feedback received in this workshop, preliminary analysis, or other factors*.**

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Additional measures to support system balancing

The Project Team will analyze options to maintain injection capability that is needed for system balancing during the non-heating season. The preliminary target is total injection capability greater than 345 MMcf/d, which is the threshold identified in SoCalGas Rule 41.

Opportunities to invest in new infrastructure to increase injection capacity at the other facilities on the SoCal system will be reviewed. Other alternatives include more restrictive imbalance rules, gas-electric coordination, and/or commercial transactions.

We currently expect that the costs or impacts that arise from measures to maintain system flexibility will be the same across all cases, which simplifies the comparison of options.

Source: *EIA*

Key uncertainties

Approaches to calculating the MW shortfall

- Alternative methods would increase the magnitude of the required investment
- Results are dependent on reasonably accurate SHR outlook

Configuration of the investment portfolios

- Use of fairly generalized portfolios
- Selections of specific technologies
- Deferral of the specification of the fifth scenario

Adjustments to these inputs and methods could result in a material change to our results

Workstream 2 walkthrough

Investment portfolios defined during Workstream 1 are a primary input of the Workstream 2 analysis

1 Run long-run (20 year) simulations of power and gas markets to estimate the impact of new infrastructure on market prices and other economic outcomes

2 Research and analysis of financial costs to build new infrastructure and financial modeling to calculate the NPV of each option

3 Comparison (ranking) of our results supports our recommendations

Results to be reported in mid-2021 include an estimate of the net cost to retire Aliso Canyon and insight into the types of resources that should be procured in order to do so

Tentative timelines

Date	Target Completion
November 17, 2020	Workstream 1 Workshop
December 2020	Finalize assumptions for Workstream 2
March 2021	Complete economic modeling for Workstream 2
March 2021	Complete financial and regulatory analysis, final recommendations
April 2021	Preliminary draft report distributed internally
May 2021	***Issuance of draft report***
May 2021	***Workstream 2 Workshop***
July-August 2021	***Final report***

The working schedule is intentionally accelerated to create the option, if needed, to revise findings or conduct additional analyses as new information becomes available while still completing our work before the December 2021 administrative deadline. Timelines and milestones are for illustrative purposes only; the Project Team and CPUC will update stakeholders regarding timing changes as they occur.

Questions?

???

Requested feedback – Modeling assumptions and inputs

1. Is our approach to modifying the Phase 2/IRP datasets reasonable?
2. **Is our exclusion of upgrades to SCG's Northern Zone from our base assumptions reasonable?**
3. Is our selection of 2027 and 2035 as the years to analyze reasonable? If not, is there a preferred option?
4. **Is our exclusion of impacts in 2027 and 2035 attributable to potential changes to Resource Adequacy rules reasonable?**
5. Are the "key uncertainties" described in the materials associated with the workshop reasonable?
6. Is the composition of the four investment options that are specified reasonable? If not, is there an option that is preferred for further analysis?
7. Please identify any of the specific assumptions or inputs discussed during the workshop or provided in the supporting materials that are unreasonable or that should be replaced with a preferred alternative.

Requested feedback – Methods and process

Methods

8. Is our approach to allocating the modeled gas shortfall based on unit heat rates reasonable? If not, is there a preferred approach?
9. Is our approach to define the fifth investment option after modeling and analyzing the first four reasonable?
10. **How should we value reductions in carbon emissions in Workstream 2?**
11. **Aside from reductions in the cost of delivered energy, what benefits should we capture in the Workstream 2 analysis of the investment options?**
12. Aside from the capital and financing costs to build new infrastructure, what costs should we capture in our Workstream 2 analysis of the investment options?

Process

13. If the data provided at the CPUC website are insufficient, please indicate which datasets should be added.
14. **Should another workshop be held between now and the one currently scheduled for April 2021? If so, when and to discuss what topics?**

Thank you for participating

Thank you!