Technical Workshop on the Aliso Canyon Scenarios Framework

Energy Division

California Public Utilities Commission

July 31, 2018

Agenda

9:30 a.m. – 9:45 Introduction

Liane Randolph, *Commissioner*

9:45 – 10:00 Workshop Objectives, Discussion Guidelines, Introductions

Jean Spencer, *Program and Project Supervisor*

10:00 – 11:30 Hydraulic Modeling

Khaled Abdelaziz, Ph.D., *Utilities Engineer*

- 30 minute presentation
- 1 hour discussion

11:30 – 12:30 Lunch Break

12:30 – 2:00 Production Cost Modeling

Donald Brooks, *Program and Project Supervisor*

- 30 minute presentation
- 1 hour discussion

2:00 – 2:15 Break

2:15 – 3:45 Economic Modeling

Mounir Fellahi, *Regulatory Analyst*

- 30 minute presentation
- 1 hour discussion

3:45 – 4:00 15 Minute Break

4:00 – 5:00 Public Comment

Introduction

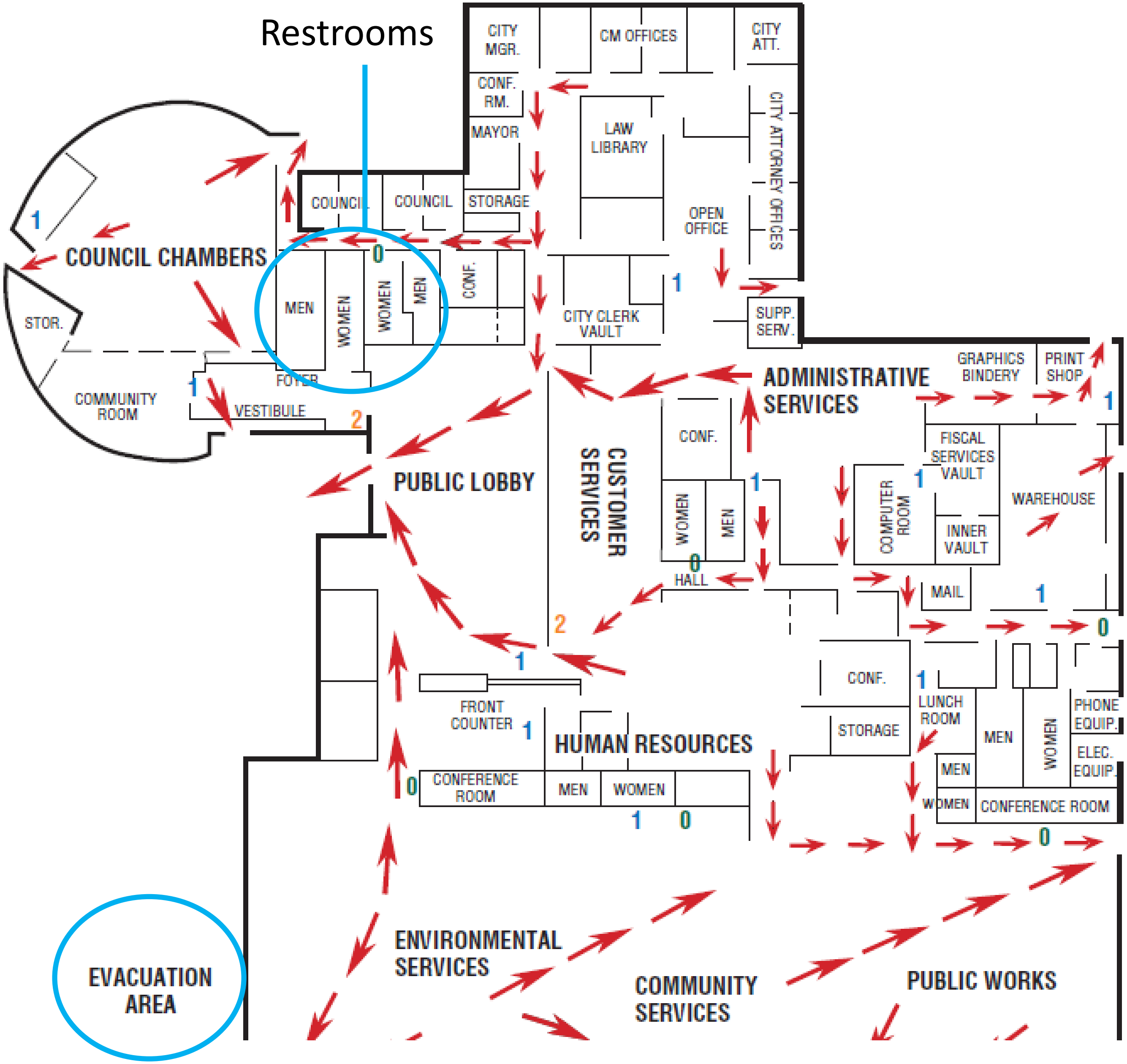
Liane Randolph

Assigned Commissioner

Workshop Objectives & Discussion Guidelines

Jean Spencer

Natural Gas Program and Project Supervisor


Restrooms
CITY MGR.
CM OFFICES
CITY ATT.
CONF. RM.
MAYOR
LAW LIBRARY
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ENVIRONMENTAL SERVICES
COMMUNITY SERVICES
PUBLIC WORKS
EVACUATION AREA

Workshop Objectives

- Information sharing:
  - Present information about models and proposed scenarios and assumptions;
  - Solicit feedback; and
  - Promote open, informal discussion

Workshop Scope

- In scope:
  - Discussion of modeling scenarios and assumptions

- Out of scope:
  - Issues addressed in other proceedings or by other agencies
  - Possible changes to the SoCalGas system that could reduce the need for Aliso Canyon
    - Phase 1 modeling will focus on whether use of Aliso can be eliminated or minimized given the existing gas system and the likely future system given current legislation and demand trends
    - Parties may model their own scenarios and submit them into the record in Phase II

Phase I Schedule

ALJ Ruling entering into record Energy Division's Final Staff Proposal on scenarios, assumptions and models.	August 30, 2018
Deadline to file requests for Phase 1 hearings (as set forth in Scoping Memo).	September 25, 2018
Concurrent Opening Comments on Energy Division's Final Staff Proposal filed and served.	September 25, 2018
Concurrent Reply Comments on Energy Division's Final Staff Proposal filed and served.	October 9, 2018
Assigned Commissioner's Ruling adopting scenarios, assumptions and models and concluding Phase 1.	November 14, 2018

CPUC Guiding Principles

Ensure safe, reliable utility service and infrastructure at just and reasonable rates, with a commitment to environmental enhancement and a healthy California economy.

Safe

Reliable

Just & Reasonable Rates

Environmentally Responsible

Workshop Format

- Description of model
  - Clarification questions
- Overview of proposed scenarios and assumptions and trends from the comments
- Discussion of proposed scenarios and assumptions

Discussion Logistics

- Parties to the Proceeding:
  - Please line up at the mic during the comment period.
  - We will stop midway through the discussion to take questions related to the modeling received via email: AlisoOII@cpuc.ca.gov
- Members of the Public:
  - To speak during the Public Comment period, please sign up with our Public Advisor.

Khaled Abdelaziz

- Ph.D. in Computational Fluid Dynamics from the University of Maryland.
- Master’s degree in transient analysis and surge alleviation in pipelines.
- Bachelor’s degree in Mechanical Engineering
- Two years in the Federal Government working on benefit-risk assessment.
- Taught undergraduate Fluid Mechanics for over a decade.

Hydraulic Modeling

Khaled Abdelaziz, Ph.D.

Utilities Engineer

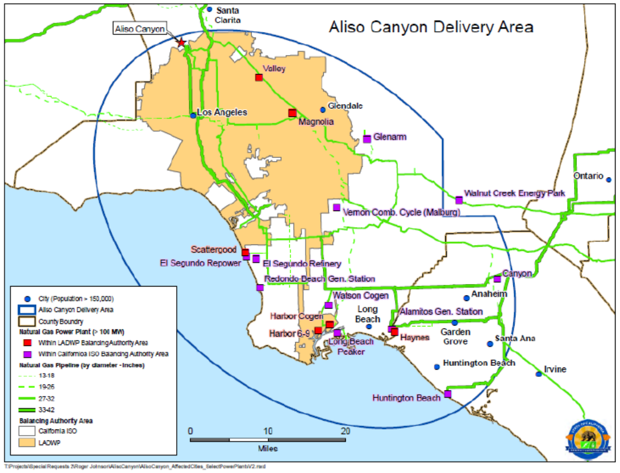
Outline

- Background & Purpose
- Overview of SoCalGas System
- Reliability Assessment
- Feasibility Assessment
- Parties Comments
- Open Discussion

Background & Purpose

Background on the Use of Aliso

- Biggest natural gas storage field in Southern California.
- When daily gas load is higher than pipeline flowing capacity, gas is withdrawn from Aliso Canyon storage field.



- The traditional role of gas storage at Aliso Canyon is to leverage seasonal variations in gas prices.
- Mitigate pressure swings. When daily gas load is highly variable, rapid increases or decreases in hourly load can cause large pressure swings. Withdrawals from or injections into Aliso mitigate the pressure swings.

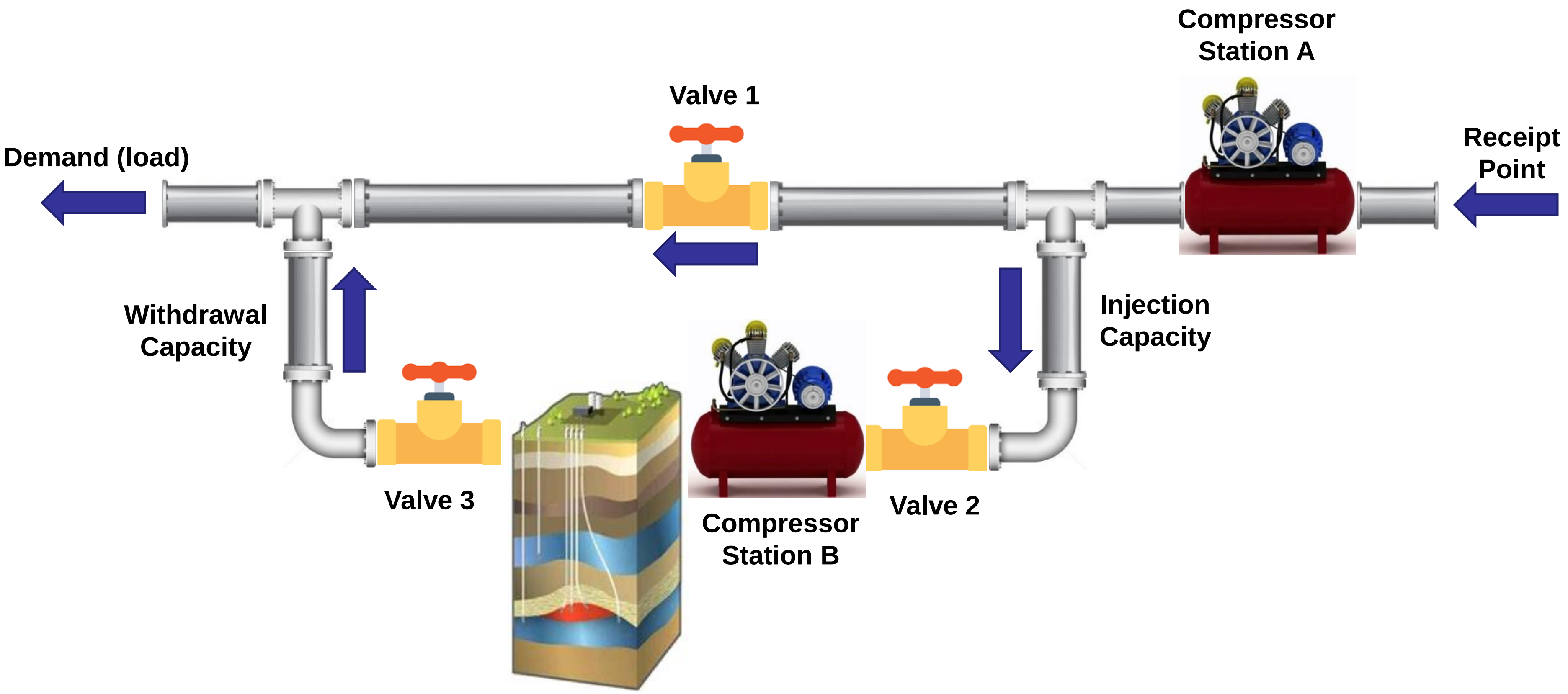
Purpose of Hydraulic Modeling

- Determine whether use of Aliso Canyon natural gas storage field (AC) can be eliminated or minimized while still maintaining reliability of gas and electric power systems.*
- If AC is needed to maintain reliability, then what is the minimum working gas capacity needed?*
- Is it possible to achieve the minimum level of inventory resulting from the reliability assessment throughout a typical year (feasibility assessment)?

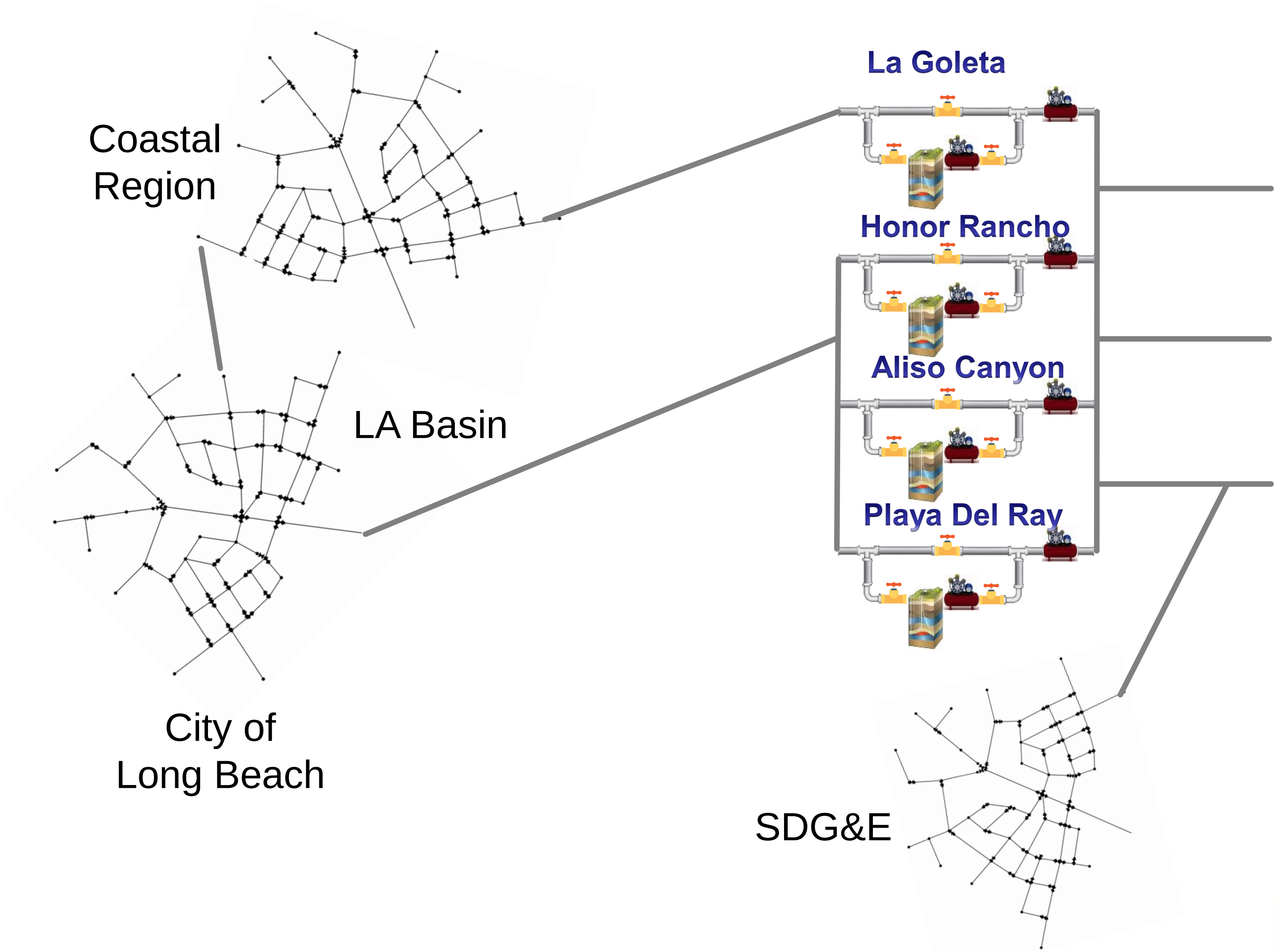
* Public Utilities Code 715

Overview of SoCalGas System

Overview: Building Block



Overview: SoCalGas Pipe Network



Overview: Receipt Points

Upstream Capacity to Southern California

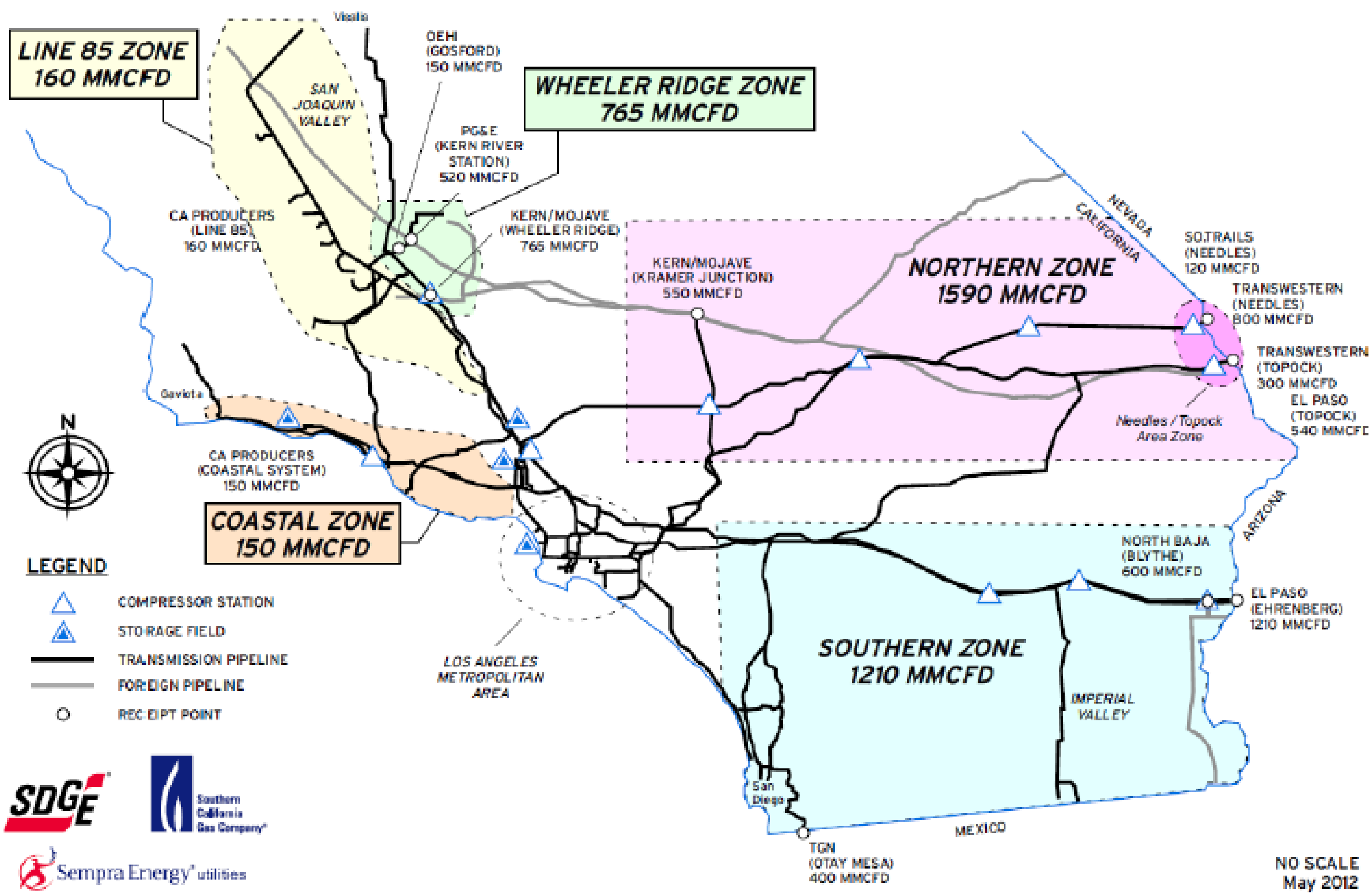
Pipeline	Upstream Capacity (MMcf/d) — CGR 2018	Upstream Capacity (MMcf/d) — CGR 2016
El Paso at Blythe	1,210	1,210
El Paso at Topock	540	540
Transwestern at Needles	1,150	1,150
PG&E at Kern River	650 (1)	650 (1)
Southern Trails at Needles	120	120
Kern/Mojave at Wheeler Ridge	885	885
Kern at Kramer Junction	750	750
Occidental at Wheeler Ridge	150	150
California Production	210	310
TGN at Otay Mesa	400	400
North Baja at Blythe	600	600

CGR 2018 CGR 2016

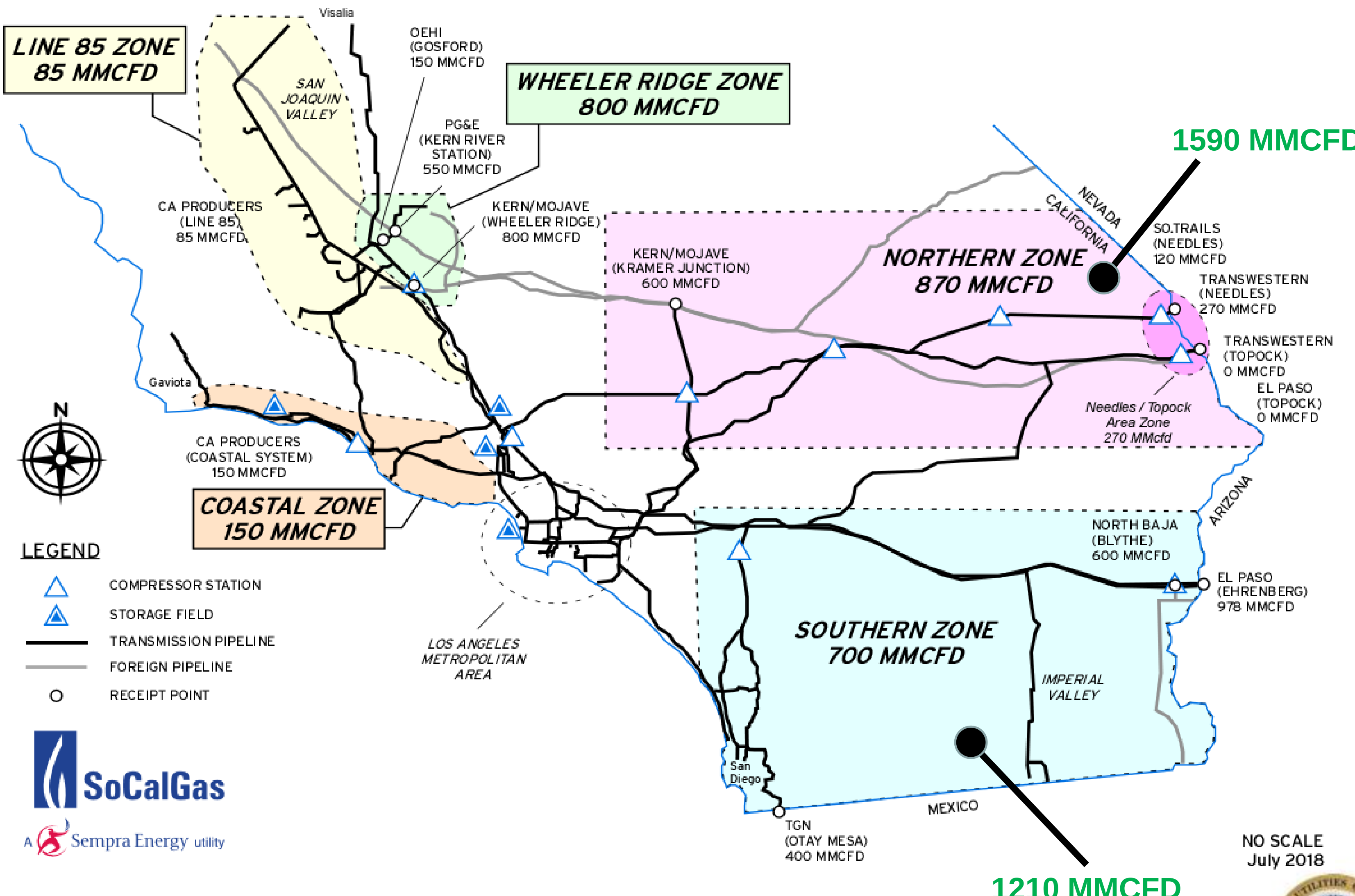
(1) Estimate of physical capacity.

*California Gas Reports. https://www.socalgas.com/regulatory/cgr.shtml

Overview: <u>Nominal</u> Zone Capacities



Overview: Present Zone Capacities



As of July 12th, 2018
These are not permanent zone capacities

Overview: Firm Capacity and Restrictions

(CGR 2016)

SoCalGas/SDG&E Current Firm Receipt Capacity

Transmission Zone	Total Transmission Zone Firm Access (MMcf/d)	Specific Point of Access [1] (Limitations)[2] (MMcf/d)
Southern	1,210	EPN Ehrenberg (1,010)
		TGN Otay Mesa (400)
		NBP Blythe (600)
Northern	1,590	EPN Topock (540)
		TW Topock (300)
		TW North Needles (800)
		QST North Needles (120)
		KR Kramer Junction (550)
Wheeler Ridge	765	KR/MP Wheeler Ridge (765)
		PG&E Kern River Station (520)
		OEHI Gosford (150)
Line 85	160	California Supply
Coastal	150	California Supply
Other	N/A	California Supply
Total	3,875	

July 9th, 2018

700	MMcf/d
870	MMcf/d
800	MMcf/d
85	MMcf/d
150	MMcf/d
2605	MMcf/d

Overview: Storage Fields

La Goleta (LG)

- Limited access to pipelines
- Limited support of peak day loads in LA Basin
- Used more as “base load” support

Playa Del Rey (PDR)

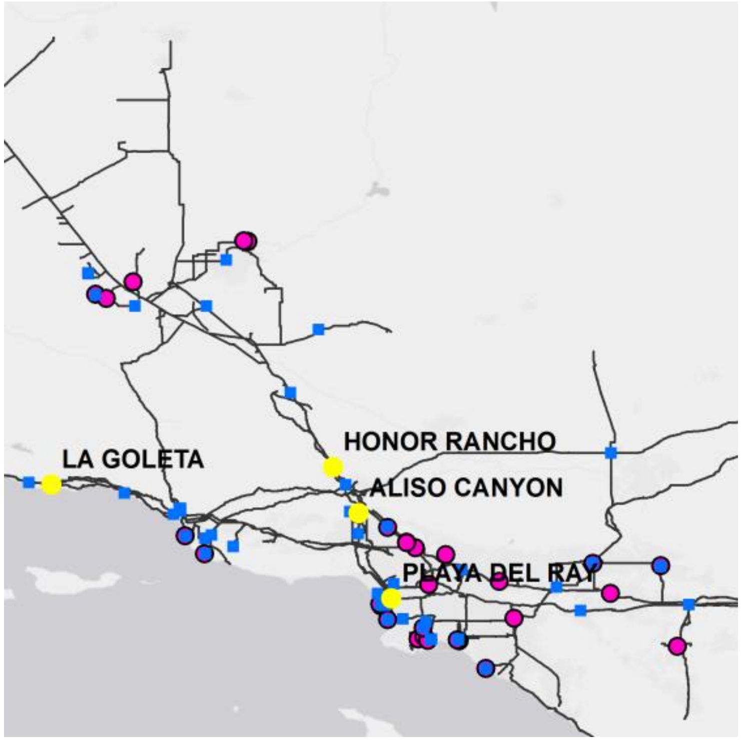
- Smallest storage capacity
- Close to LA Basin
- Short refill time (a few days)
- Useful on any peak day

Honor Rancho (HR)

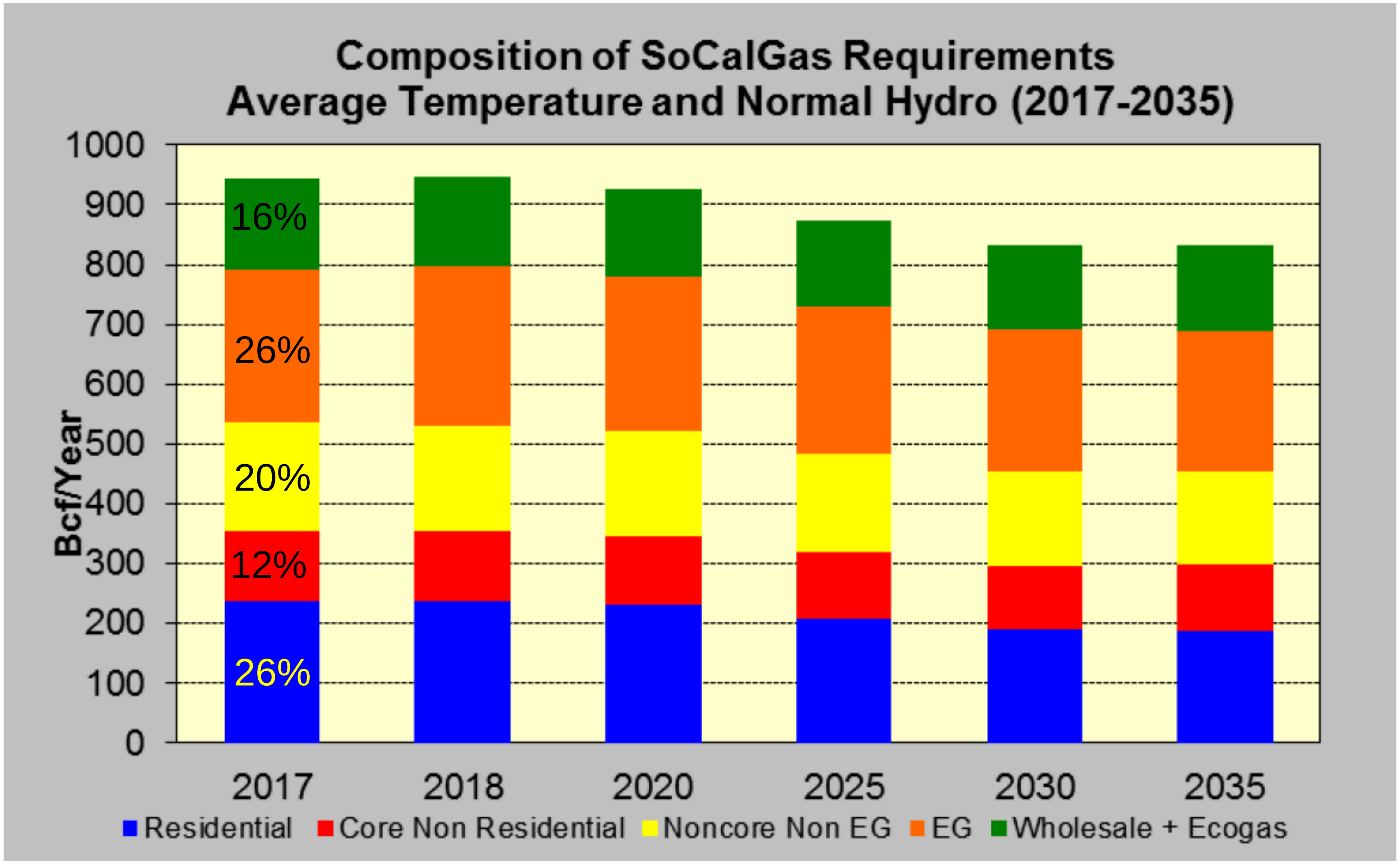
- Better access to pipelines serving LA Basin
- However, withdrawals may compete with Wheeler Ridge receipts
- Capacity limited by pipeline transmission

Aliso Canyon (AC)

- Better access to pipelines serving LA Basin
- Biggest storage capacity
- Capacity limited by pipeline transmission



Overview: Gas Demand (Load)



(California Gas Report 2018)

- Recorded year 2017 (2.55 Bcf/d). (66% of nominal zonal capacity)
- Forecasts for 2018-2035.
- Wholesale includes sales to the City of Long Beach, City of Vernon, SDG&E, Southwest Gas Corporation and Ecogas in Mexico.

Overview: Winter Cold Day (1-10)

(California Gas Report 2018)

Winter Cold Day Demand Condition
(MMcf/Day)

Year	SoCalGas Core (1)	SDG&E Core (2)	Other Core (3)	Noncore NonEG (4)	Electric Generation (5)	Total Demand
2018	2,838	384	100	658	985	4,965
2019	2,822	382	101	654	989	4,949
2020	2,802	381	102	654	1,048	4,987
2021	2,781	379	102	651	1,036	4,950
2022	2,753	375	103	647	1,030	4,908
2023	2,708	373	104	639	979	4,804
2024	2,672	372	104	632	990	4,771

128% of nominal zonal capacity

Notes:
(1) 1-in-10 peak temperature cold day SoCalGas core sales and transportation.
(2) 1-in-10 peak temperature cold day SDG&E core sales and transportation.
(3) 1-in-10 peak temperature cold day core demand of Southwest Gas Corporation, City of Long Beach and City of Vernon.
(4) Noncore-Non-EG includes noncore Non-EG end-use customers of SoCalGas, SDG&E, Southwest Gas Corporation, City of Long Beach, City of Vernon, and all end-use customers of Ecogas.
(5) UEG/EWG Base Hydro + all other Cogeneration customers

Overview: Core Extreme Peak Day (1-35)

(California Gas Report 2018)

Core Extreme Peak Day Demand (MMcf/Day)

Non-core curtailed

Year	SoCalGas Core Demand [1/]	SDG&E Core Demand [2/]	Other Core Demand [3/]	Total Demand	Core 1-10
2018	3,003	407	117	3,527	3,322
2019	2,987	406	118	3,511	3,305
2020	2,966	405	119	3,490	3,285
2021	2,945	403	120	3,468	3,262
2022	2,916	398	120	3,435	3,231
2023	2,870	396	121	3,388	3,185
2024	2,833	395	122	3,350	3,148

Difference =~ 0.2 Bcf

Notes:
(1) 1-in-35 peak temperature cold day SoCalGas core sales and transportation.
(2) 1-in-35 peak temperature cold day SDG&E core sales and transportation.
(3) 1-in-35 peak temperature cold day core demand of Southwest Gas Corporation, City of Long Beach and City of Vernon.

Reliability Assessment

Reliability Assessment: Goals

- Simulation of the gas system under conditions of the reliability standard:
  - 1-in-10 year (peak).
  - 1-in-35 year (extreme peak).
- Determine the minimum monthly inventory targets for underground storage at each facility to support the required system performance (demand) under the stressed conditions of the reliability standard.
- NOT a historical operating day.

Reliability Assessment: Assumptions

- Will use all allowable operational actions to achieve required system performance:
  - Flowing supplies at receipt points are maximized to minimize withdrawals from storage, including Aliso.
  - Hydraulic modeling identifies maximum gas supply that could be scheduled into the system (MAOP and Compressor constrained).
  - Best practices for pipeline operations (e.g. valve positions).
  - Curtailment of gas loads allowed under the specific standard.
- If scheduled flowing supplies are not achievable, the differences between scheduled and actual deliveries must be taken into account.
  - Assessment study shows typical imbalance of 10% between actual gas receipts and total scheduled gas.
  - An imbalance to be 5% difference for the reliability assessment.
  - Imbalance is driven by high OFO penalties, gas shippers are more conservative in scheduling gas.

Reliability Assessment: Pipeline Outages

- Planned outages can be scheduled to occur outside of the months with the most severe operating conditions.
- Unplanned outages are frequent enough that they must be accounted for in the modeling.
- Key factor: location of outage and number of concurrent outages on a peak day. Use historical records.
- Propose subjecting system to a single plausible unplanned outage that results in max loss of aggregate gas send out.

Reliability Assessment: Pipeline Outages

- Step 1: Unplanned outages applied at non-Aliso components.
- Step 2: Use hydraulic model to evaluate need for Aliso withdrawals.
  - If Aliso withdrawals are not required →analysis is complete
  - If Aliso withdrawals are required →additional analysis needed
- Step 3 (if needed): Evaluate impact of Aliso outages.
  - Determine largest plausible Aliso outage
  - If largest Aliso outage < largest non-Aliso outage → analysis complete
  - If largest Aliso outage > largest non-Aliso outage → must reanalyze impact of Aliso outage
    - Run hydraulic model to re-evaluate needed Aliso withdrawals

Reliability Assessment: Storage Fields

Playa Del Rey (PDR)

- Best practice is to assume maximum inventory on any peak day.

La Goleta (LG)

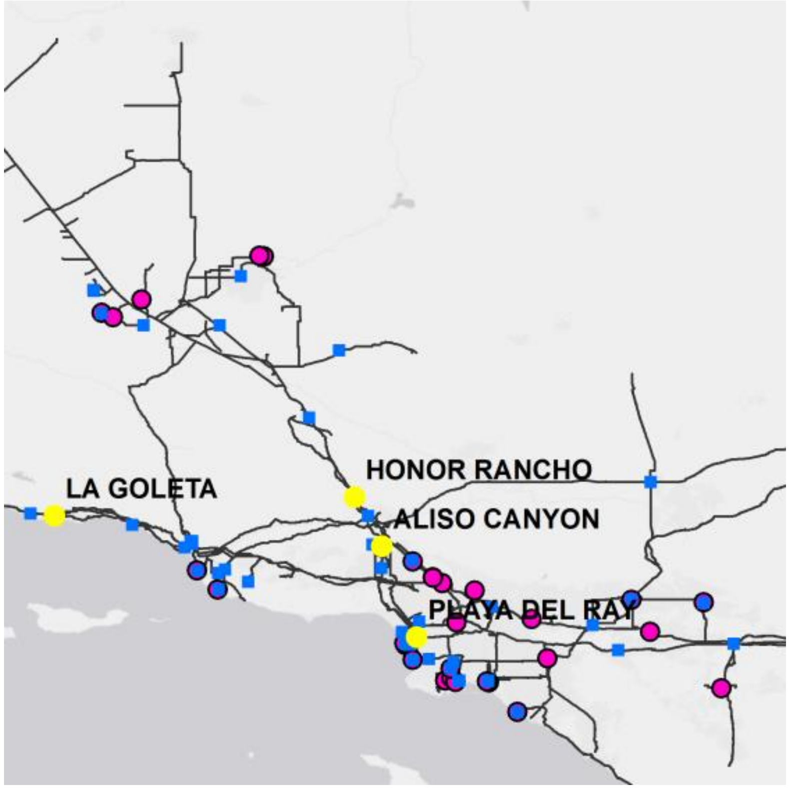
- Effectively at maximum inventory on any peak day.
- Limited by pipeline transmission capacity.

Honor Rancho (HR)

- Better access to pipelines serving LA Basin.
- Withdrawals compete with Wheeler Ridge receipts.
- Withdrawals limited by pipeline transmission capacity.

Aliso Canyon (AC)

- <u>The Reliability Assessment is computing the required withdrawals from Aliso.</u>
- <u>No assumptions about the gas storage inventory is required.</u>
- <u>Must incorporate pipeline transmission constraints.</u>



Reliability Assessment: Gas Demand

- **Base Gas Load Profiles**
  - *Core gas load*
    - 1-in-10: Most recent California Gas Report or directly from SoCalGas.
    - 1-in-35: Most recent California Gas Report or directly from SoCalGas.
  - *Non-core, non-electric gas load*
    - 1-in-10: Most recent California Gas Report or directly from SoCalGas.
    - 1-in-35: Most recent California Gas Report or directly from SoCalGas.
  - *Non-core, electric gas load*
    - 1-in-10: Economic optimal production cost model with no gas supply constraints and meeting minimum NERC reliability standards.
    - 1-in-35: Out-of-merit production cost model that reduces gas consumption to the minimum to meet NERC reliability standards.

Reliability Assessment: Gas Demand

- **Gas Curtailments**
  - *Core gas load*
    - 1-in-10: None.
    - 1-in-35: None.
  - *Non-core, non-electric gas load*
    - 1-in-10: None.
    - 1-in-35: Full curtailment to zero, while maintaining certain carve outs are specified in Rule 23.
  - *Non-core, electric gas load*
    - 1-in-10: None: This implies that the electric production cost model is unconstrained by gas availability.
    - 1-in-35: Full curtailment to zero. This implies that the electric production cost model should not allow any consumption of natural gas for electric generation under this scenario.

Reliability Assessment: Output

- Monthly Minimum Storage (Bcf)
  - Required hourly (or sub-hourly) withdrawal rate is converted into required gas storage volume using SoCalGas facility specific curves.
  - Required hourly withdrawals to meet 1-in-10 and 1-in-35 year analysis for every month studies.

	LG		HR		PDR		AC	
	1-10	1-35	1-10	1-35	1-10	1-35	1-10	1-35
Mar, 2020	15	10	10	9	10	9		
April, 2020	12	11	5	2	5	2		
.	10	5	5	2	5	2		
Feb, 2020	6	8	10	8	10	8		
2024	8	4	5	3	5	3		
2030	17	12	6	4	6	4		

Reliability Assessment: Summary

1. Collect base gas load profiles for core, non-core-non electric, and non-core-electric (downstream boundary condition).

2. Define allowable gas curtailments (downstream boundary condition).

3. Find (solve for) the initial steady state of the pipeline system (initial condition at t=0) that maximizes the flow rate at the receipt points (upstream boundary condition) without Aliso Canyon.

4. Run the hydraulic model for peak day and determine hourly withdrawals needed from storage (non-Aliso first, then Aliso if needed).

5. Use curves of maximum withdrawal rate versus gas storage to convert required gas storage withdraw rates to a minimum gas storage volume requirement.

6. Complete this analysis for each month of the year to determine a minimum gas storage inventory schedule for the entire year under study at each gas storage facility.

Feasibility Assessment

Feasibility Assessment: Goals

- Determine if the minimum inventory targets from the reliability assessment are feasible to achieve throughout an average (typical) year.

	LG		HR		PDR		AC	
	1-10	1-35	1-10	1-35	1-10	1-35	1-10	1-35
Mar, 2020	15	10	10	9	10	9		
April, 2020	12	11	5	2	5	2		
.	10	5	5	2	5	2		
Feb, 2020	6	8	10	8	10	8		
2024	8	4	5	3	5	3		
2030	17	12	6	4	6	4		

Feasible?

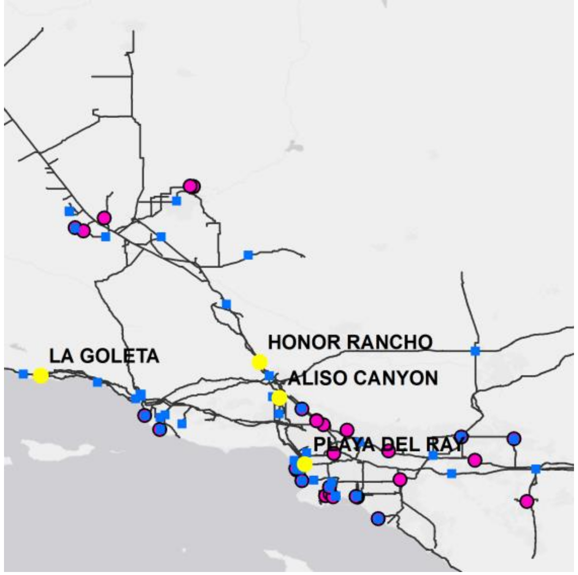
Minimum monthly inventory required

Feasibility Assessment: Assumptions

- The stressed conditions imposed in the Reliability Assessment are infrequent, or that they are (on average) balanced out by abnormally mild system conditions, and do not significantly impact the total storage volumes over a several-month time frame.
- Carried out under "typical" or "nominal" demand conditions defined on a monthly basis to assess the nominal available gas storage injection and withdrawal rates.
- Flowing Gas Supplies at the Receipt Points: Similar to the Reliability Assessment, the flowing supply available at the receipt points is assumed to be 5% lower than the maximum available scheduling capacity.

Feasibility Assessment: Storage Fields

- **Playa Del Rey (PDR)**
  - The PDR storage field has relatively small storage capacity.
  - This means that it cannot be continually drawn down.
  - In the nominal monthly day of the Feasibility Assessment, <u>PDR must start and end the day with the same quantity of stored gas</u>, i.e., injections and withdrawals must be balanced on a daily basis for a nominal day.
  - This “nominal day balance” condition is used for PDR in the Feasibility Assessment instead of a monthly minimum gas storage target.



Feasibility Assessment: Storage Fields

- **Non-PDR (LG, HR, and AC)**
  - Storages are an order of magnitude bigger than PDR.
  - Storages support consistent net withdrawals or net injections over the monthly period of the Feasibility Assessment. In the Feasibility Assessment, for each month of the analysis year:
  - If net injections are available:
    - Distribute across the non-PDR facilities.
    - Ensure all facilities are at least above their required monthly minimums.
    - Maximize the total gas stored in aggregate fleet of storage facilities.
  - If net withdrawals are needed:
    - Distribute across the non-PDR facilities.
    - Ensure all facilities are at least above their required monthly minimums.
    - Ensure all gas loads are met without imposing curtailments.
  - Must consider variation in withdrawal and injection capacity for a whole month calculation.

Feasibility Assessment: Gas Demand

- **Base Gas Load Profiles**
  - *Core gas load*—Expected or average daily core gas load profile for each month of the analysis year from the most recent California Gas Report or directly from SoCalGas.
  - *Non-core, non-electric gas load*— Expected or average daily core gas load profile for each month of the analysis year from the most recent California Gas Report or directly from SoCalGas.
  - *Non-core, electric gas load*—The daily gas consumption profiles from a year-long electric production cost model are averaged within each month of the year to define the expected or average daily non-core, electric gas load. No Constraints.
- **Gas Curtailments**
  - *Core gas load*: None.
  - *Non-core, non-electric gas load:* None.
  - *Non-core, electric gas load*: None.

Feasibility Assessment: Outages

- Each gas pipeline system model (one model per month of the year) should be subject to reductions in flowing supplies and reductions in storage operations that are consistent with expectations from historical records of that specific month.
- If no sufficient data exists to determine the expected planned and unplanned outages on a monthly basis, the expected outages may be determined on a yearly basis and the same outages applied in each of the twelve monthly gas system models.

Feasibility Assessment: Summary

1. Collect hourly load profiles under nominal operating conditions for core, non-core-non-electric and non-core-electric.
2. Run model for the nominal day in each month. Any excess gas is used to support injections to storage. Withdrawals are used to close up deficits.
3. If injections less withdrawals are sufficient to meet minimum storage from reliability assessment, it is deemed feasible
4. Injections and withdrawals are integrated over each day of the month to compute gas storage volume at the start of the next month.
5. If simulated storage volumes are above the minimum gas storage scheduled determined from the Reliability Assessment, the gas system is deemed feasible.

Reliability & Feasibility Assessment Comparison

	Reliability	Feasibility
Demand	Peaks (1-10 & 1-35)	Typical
Outages	Unplanned	Unplanned and Planned
Curtailment	Depends (None & some)	None
Scenarios	32 (12 months + 4 seasons) X 2	12-16
Storage	Withdrawal	Injection & Withdrawal
Output	Minimum storage inventory	Yes/No

Comments

Comments

IN	Issam Najm
CAISO	California Independent System Operator
CEERT	Center for Energy Efficiency and Renewable Technologies
EDF	Environmental Defense Fund
SC	Sierra Club
CLA	County of Los Angeles
SCPOU	Southern California Publicly Owned Utilities
URM	Utility Reform Network
MEMH	Magnum Energy Midstream Holdings, LLC
SCG	Southern California Gas
SCE	Southern California Edison

Comments

Disambiguation: Number of scenarios

The number of scenarios (or transient simulations) is 32 for the reliability assessment and potentially 12-16 for the feasibility assessment.

	Reliability	Feasibility
Demand	Peaks (1-10 & 1-35)	Typical
Outages	Unplanned	Unplanned and Planned
Curtailment	Depends (None & some)	None
Scenarios	32 (12 months + 4 seasons) X 2	12-16
Storage	Withdrawal	Injection & Withdrawal
Output	Minimum storage inventory	Yes/No

Comments

Disambiguation: Alternative operational actions

EDF: Elaborate on “alternative operational actions” that would reduce the Aliso requirement to zero; test the operational actions in the scenarios.

SCG: Elaborate on “alternative operational actions” that would reduce the Aliso requirement to zero; test the operational actions in the scenarios.

MEMH: Reliability Assessment: Staff suggested additional actions may be taken beyond the set of operational actions defined; Identify at least one action that may be modeled.

MEMH: Reliability Assessment: Magnum should be used as a basis for an “additional actions” scenarios in the framework

CPUC: Within the definition of the reliability standard, there are no “alternative operation actions.” The only actions that can be taken, beyond operation of the natural gas system according to best practices, is the curtailment of gas loads as specified in the framework. (discuss stage 4 OFO).

Comments

Use year 2020 instead of 2019 for near term

CAISO: Recommends 2020 rather than 2019 study year, because the studies are expected to be completed in the 2019 timeframe.

SCG: Modeling in near term should be done for 2020.

CPUC: Agrees.

SCPOU: If actual data for 2019 are available, use actuals.

CPUC: The whole purpose of running simulations is to predict the future need of Aliso. Why run present or past demand?

Comments

Suggestions to consider generic system modifications

CEERT: Phase 1 does not answer the key question – "What physical changes to the system will allow the phaseout/shutdown of Aliso Canyon and how much will that cost?"

EDF: Feasibility Assessment: Suggestion for an additional 76 scenarios for a total of 108 to examine different policy and demand-side possibilities.

SC: Last year, Sierra Club's comments focused on the need for modelling to identify how solutions that reduce the need for natural gas, avoidance of new gas plants, and deployment of non-fossil generating resources enable Aliso's closure. This update fails to recognize demand reduction as a tool.

CPUC: Beyond the scope of Phase 1.

Comments

Comments from IN

IN: Hydraulic model should also look at what the system should look like without Aliso.

CPUC: The hydraulic analysis is partially doing that by withdrawing from non-Aliso storage field first. Modelers have to manually input whether natural gas is being injected or withdrawn.

IN: Use an iterative process that identifies constraints. Arrive at what constraints need to be removed to allow eliminating Aliso Canyon.

CPUC: Beyond the scope of Phase 1. Constraints are known (Maximum allowable operating pressure of the pipeline, performance of compressor stations, gas demand, etc.). These are mostly boundary conditions (input data) and are subject to verification before running the simulations. System might actually need “adding” components rather than “removing” constraints, which is beyond the scope of phase I. Discuss.

Comments

Do not use SCG to conduct the hydraulic modeling

IN: Do not use SoCalGas to conduct the hydraulic modeling.

CLA: Pleased LANL is assisting with hydraulic modeling but maintains that SoCalGas should not participate in model.

CPUC: was unable to find a contractor willing and capable of conducting the analysis. However, SCG analysis will be thoroughly reviewed and is overseen by:

CPUC (staff has expertise in water hammer, pipeline design, developing Fluid Mechanics solvers, and running commercial packages for pipelines).

LANL (staff has multi-disciplinary expertise in Fluid Mechanics and optimization)

Comments

Define a “successful” simulation (SCG)

A simulation that results in the following:

- Pressure at all demand nodes is held above the minimum required pressure at these demand points at all times.
- Maximum pressure at any point at any time does not exceed the MAOP at any time.
- Linepack is restored, i.e. the volume of gas present in the pipeline at the end of the simulation is the same as at the beginning of the simulation.
- Able to maintain the required withdrawal (or injection) capacity.

Comments

Historical analysis of flow supply

SCG: Feasibility Assessment: on page 18: expand on assumption of flowing supply available assumed to be 5% lower relative to maximum available scheduling capacity.

SCG: It is unreasonably high to assume a 95% receipt point utilization. Historical averages are closer to 80-85% utilization.

SCPOU: Energy Division states SoCalGas experiences "90% utilization of scheduled receipts," appearing as a maximum operating capacity. Recommends examination of SoCalGas operating data to determine percentage of maximum operating capacity.

MEMH: Reliability Assessment: 95% receipt point utilization rate is not realistic, staying within historical range, such as 80%, is more realistic.

MEMH: Feasibility Assessment: 95% receipt point utilization rate is not realistic, suggests 70% for Feasibility Assessments.

EDF: Feasibility Assessment: Assumptions for storage facilities, flowing gas supplies at receipt points are faulty; unplanned outages are double counted in Reliability Assessment.

Comments

Historical analysis of flow supply

CPUC: Los Alamos National Lab to provide recent historical data analysis. Resolve ambiguity and discuss.

SCG: Receipt Point Utilization (Factor) = ratio of average actual delivery at receipt point to firm capacity (contracted) (ranges from 0 to 1 or 0% to 100%). SCG suggests 80%.

CPUC: 5% within maximum available scheduling capacity. This is delivered vs. scheduled.

Comments

Outages

SCG: Reliability Assessment: Pipelines and infrastructure age while technology to identify maintenance issues advances; combination means likely more outages in future. Commission should perform sensitivity analysis to determine impact of potential multiple outage scenarios.

CPUC: For the Reliability Assessment, we propose that gas pipeline system be subject to a single plausible unplanned outage (pipeline or storage) that results in the maximum loss of aggregate gas send out.

LANL: Current framework calls for one unplanned pipeline and one unplanned storage outage. Los Alamos to review historical data from 2016 to reassess.

Discussion

Discussion Points

- Natural gas demand for future years must include effect of climate change and effect of state policies.
- Power flow modeling should be used to inform both the hydraulic and production cost modeling.
- Reference to the 17 natural gas-fired power plants does not recognize that several of the plants will be retired.
- Clarify all assumptions, inputs and outputs.
- Consider intra-day gas market rules, such as imbalance market.
- "Preference" to operations of non-Aliso facilities is unclear and does not reflect current electric dispatch as determined by CAISO.
- Clarify planned and unplanned pipeline outages.
- Consider changes to gas demand over time.

Discussion Points

1. Is modeling each month necessary? Or is summer peak and winter peak sufficient?
2. What should be used for the preceding month inventory?
   - I. Inventory from reliability.
   - II. Inventory from feasibility.
   - III. Smaller of the two.
   - IV. Bigger of the two.
3. Is modeling of long term needed (2024 & 2030)?
4. Which historical time period should be used to determine typical outages?
   - I. Before October, 2015.
   - II. After October, 2015.
   - III. Some weighted average of I & II.

Donald Brooks

- Program and Project Supervisor in Energy Division
- M.S. in Environmental Policy from Bard Center for Environmental Policy.
- 13 years of experience at the CPUC, in Resource Adequacy and production cost modeling.

Production Cost Modeling

Donald Brooks

Program and Project Supervisor

Purpose of Production Cost Modeling

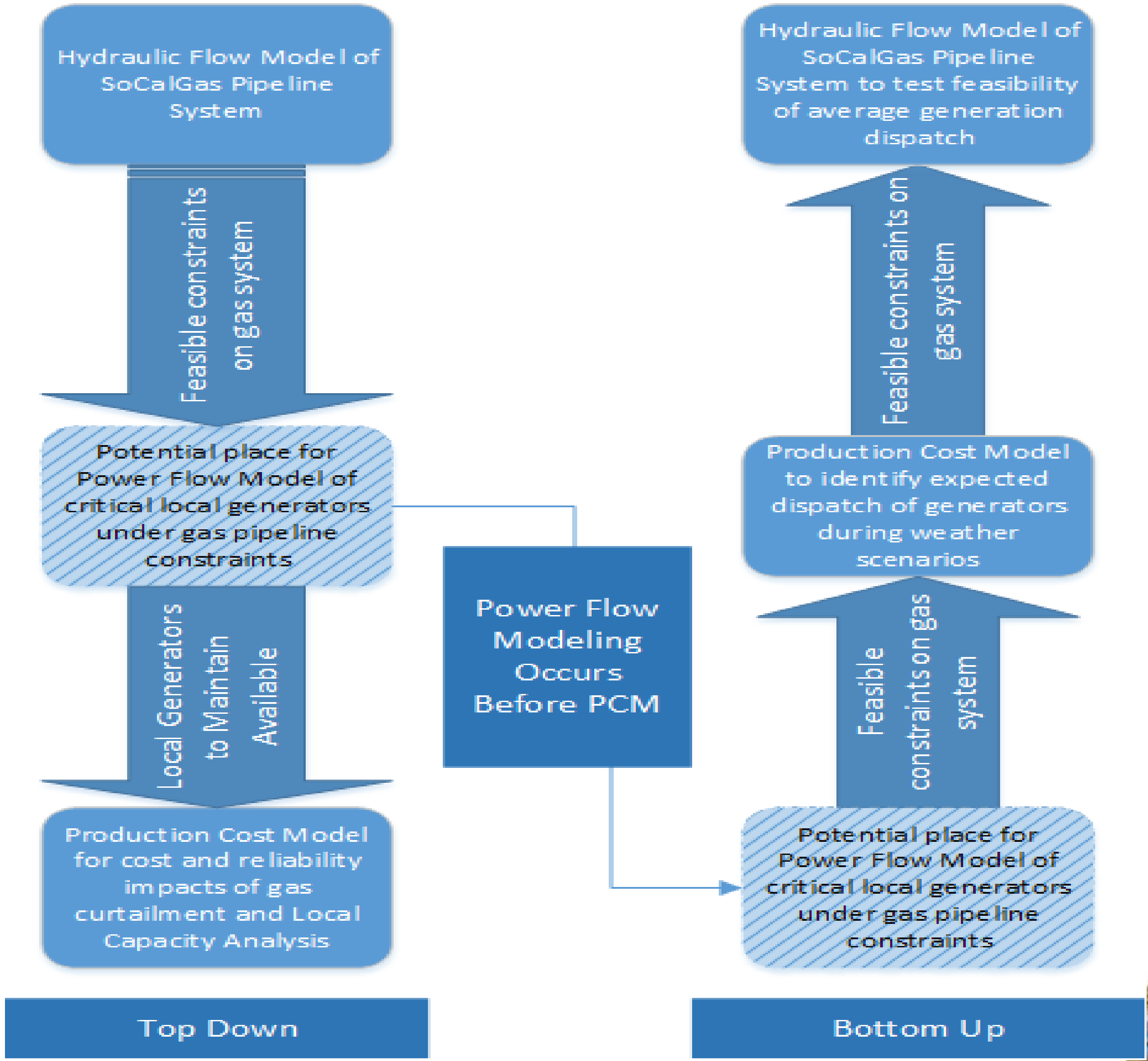
- Production Cost Modeling (PCM) is used to evaluate the reliability impacts (in terms of Loss of Load Expectation or LOLE) of a given profile of electric generation and customer demand.
  - Does the curtailment or closure of Aliso Canyon produce significant and undesirable increases in LOLE compared to the pre-existing gas storage and supply situation?
- PCM is also used to evaluate the cost impacts (in terms of total dollars of production cost from fuel, variable O&M and GHG costs) of a given profile of electric generation and customer demand.
  - Does the curtailment or closure of Aliso Canyon produce significant and undesirable increases in production costs compared to the pre-existing gas storage and supply situation?

High Level Modeling Method

- Energy Division is proposing to use a Production Cost Modeling (PCM) approach to study effects on the electric system of the curtailment or closure of the Aliso Canyon gas storage field.
- PCM is a probabilistic reliability planning approach (e.g. security-constrained planning) – primary goal is to reduce risk of insufficient generation to an acceptable level and secondly to minimize cost of serving load
- Uncertainty considered – weather, economic load forecast, unit performance
- Simulate hourly economic unit commitment and dispatch
  - With reserve targets to reflect provision of subhourly balancing and ancillary services
  - With assumed generation fleet and load forecast in target study year
  - Across probability-weighted range of uncertainties
- Pipe and bubble representation of transmission system
  - 8 CA regions, 16 rest-of-WECC regions

Process Flow of Studies

Interaction of PCM and Hydraulic Flow Studies with Potential CAISO Power Flow Studies – Not fleshed out in Scenarios Paper



Strategic Energy Risk Valuation Model (SERVM)

- A system-level reliability planning and PCM model designed to analyze the capabilities of an electric system during a variety of conditions under thousands of different scenarios. The current dataset includes:
  - 35 historical weather year distribution (1980-2014)
  - 35 x 5 = 175 probability-weighted ***cases***
  - Each ***case*** represents one realization of a year (8760 hours) of grid operations
  - The dataset is used for probabilistic loss-of-load studies, effective load-carrying capability (ELCC) studies, and forecasting production costs and market prices in the Integrated Resource Planning (IRP) and Resource Adequacy (RA) proceedings

Input Data Development

- Energy Division staff intends to build off IRP modeling dataset.
- Unified RA and IRP Inputs and Assumptions document describes data development, sources, and modeling methods in detail (download here*)
  - Generator unit data
  - Load forecast
  - Fuel and carbon prices
  - Load, wind, solar, and hydro shapes
  - Transmission topology and constraints
  - System operating constraints
- Some changes made to IRP dataset for Aliso Canyon modeling purposes

* A draft document was posted in February 2018. An updated version describing the revised assumptions in the studies reported here will be posted soon.

Generator Unit Data

- CAISO Masterfile
  - Generator capacity, location, and operating costs and attributes
  - Unit-specific heat rates, ramp rates, startup profiles, minimum up/down times
- WECC 2028 Anchor Data Set
  - Used to populate non-CAISO generation data
  - New units under construction or units retired by study years (2020, 2024, 2030)
- RPS contracts database
  - Planned projects not yet in CAISO Masterfile
- RESOLVE model output portfolio consistent with IRP modeling
  - Incremental resource portfolio based on IRP Reference System Plan 42 MMT scenario calibrated with the 2017 IEPR forecast
- Generator Availability Data System (GADS) database
  - Planned and forced outage data

Annual Load Forecast

- 2017 IEPR California Energy Demand Forecast for CA loads
  - Use “Single Forecast Set” mid demand, mid-mid AAEE, mid-mid AAPV
  - Annual consumption energy and peak demand used to scale and stretch weather-normalized synthetic hourly consumption load shapes
  - Annual installed capacity of “baseline BTM PV” plus AAPV used to create hourly BTM solar PV shapes
  - Annual load modifiers include growth from increased EV charging, AAEE savings, and load shifting from TOU rates
  - Non-PV self-generation is left embedded in the consumption load
- WECC 2028 Anchor Data Set for non-CA load forecast

Hourly Profiles

	How developed	Sources
Load	Based on relationship between historical hourly load and weather	CAISO EMS, FERC Form 714, EIA Form 861, National Climate Data Center hourly weather
Wind	Based on relationship between historical hourly production and wind speed	NREL Western Wind Resources Dataset, NOAA hourly wind speed
Solar	Calculated production from historical irradiance and assumed technology configuration	NREL PVWatts tool, NREL National Solar Radiation Database; Tracking vs. Fixed assignment based on historical late-afternoon generation (existing units) or 75%/25% assumption (new units)
Hydro	Based on historical production	Form EIA-923: Power Plant Operations Report, CEC historical hourly monitoring
Load-modifiers	Used as-is	2017 IEPR hourly shapes for EV charging, TOU rates, AAEE savings

Specific Aliso Modeling Details

- Modifications to Aliso affected power plants
  - Complete curtailment for 1 in 35 design day based on Rule 23
  - Modifications to the operating parameters of power plants served by the SoCalGas system, that Aliso Canyon curtailment or closure - less flexible (day ahead scheduled) gas delivery means less ability to ramp or start up quickly. This translates to slower ramp rates and longer start up times
  - Effect mitigated in part as generators may be served by non-Aliso gas storage.
  - We will test a constraint that limits total gas delivery to all power plants
- Hourly demand and generation production profiles
  - 12 monthly 24 hour profiles that represent a normal operating day in 2020
  - 12 monthly 24 hour profiles that represent a stressed operating day in 2020
  - 24 hour profile for a normal operating day and stressed condition operating day in 2024 and 2030 for winter season
  - 24 hour profile for a normal operating day and stressed condition operating day in 2024 and 2030 for summer season

Production Cost Modeling Outputs

- PCM outputs include
  - LOLE of CAISO system with Aliso Canyon closed or minimally available
  - Production costs of the overall CAISO energy system with Aliso Canyon closed or minimally available
- Outputs of SERVM PCM modeling will become inputs into other parts of the modeling effort
- For the near term study year (2020) staff will create a 24 hour forecast of gas demand drawn from 24 hours of electric generation meant to represent a normal day, a stressed day, and an extreme stress day for each month, resulting in a total of 36 hourly profiles.
- For the further out years (2024 and 2030) staff will create hourly profiles representing a normal day, a stressed operating day, and hourly profile an extreme stress operating for the winter season and hourly profile also for the summer season. This results in 12 more profiles.
- Staff is open suggestion how to create single design day profiles from a set of real profiles created during PCM modeling – average of hours in a month, max or min load per month, etc.

PCM Modeling – Themes in Informal Comments

1. Energy Division did not respond to earlier party comments from last year
    1. That was on oversight – we are responding here and in revised Aliso Scenarios report. ED staff appreciates parties repeating earlier comments for us to address
2. Review electric reliability from both a “top-down” and “bottom-up” perspective. In the “top-down” approach, CPUC provides CAISO information on gas available for EG. In the “bottom-up” approach, opposite.
    1. Please refer to diagram on slide 67 – there is a place for power flow modeling to either result from or lead into PCM and Hydraulic Modeling
3. Consider using SERVM to estimate EG gas demands by simulating a smaller interval (such as a hourly, day, or a week)
    1. We plan to create appropriate inputs for the hydraulic modeling – how to crosswalk outputs and inputs is open question – open to suggestions

PCM Modeling – Themes in Informal Comments

1. Consider western region impacts identified in WECC Gas-Electric Interface Study

2. Ignores fixed cost changes beyond the purview of SERVM and RESOLVE

3. Unclear if the PCM will include the ability of non-Aliso storage assets to meet gas load

    1. ED will set up SERVM to allow that – modifications to electric generators will not reflect zero gas storage, just less and slightly more distant

4. Does not identify the demand, import capacity, outages, and wildfire risks in assumptions

Focus questions

- Are the inputs described above appropriate for use in the model as described?
- Is the proposed time horizon appropriate?
- Are LOLE and total production costs good measures of reliability and cost respectively?
- Are increased startup times and startup profiles and decreased ramp rates the best way to simulate the effect on flexibility in dispatch from electric generation resulting from the more distant gas delivery when Aliso Canyon is unavailable?
- What is the best methodology to translate hourly electric generation over a year into the 1 in 10 and 1 in 35 design standard gas demand levels needed for hydraulic modeling? Is probability weighted hourly average for weekdays in the month the appropriate method?
- Are there any other questions that should be considered?

Mounir Fellahi

- Master's degree in Agriculture and Resource Economics, UC Davis
- Master's degree in Transportation Policy and Planning, with focus on energy economics, UC Davis
- Bachelor's degree in Economics, UC Berkeley
- 3 years of graduate research assistant in economics
- 1 year of experience with Ascend Analytics

Economic Modeling

Mounir Fellahi

Public Utilities Regulatory Analyst

Overview

- Purpose of Economic Modeling
- Four Analyses
- Data Sources
- Economic Modeling Outputs
- Informal Comments
- Discussion Points

Purpose of Economic Modeling

- The economic model is intended to study the likely **economic impact** an **elimination or minimization** in Aliso Canyon storage would have on the gas system in Southern California.
- A primary goal is to estimate the impacts of reduction in Aliso gas storage on **core natural gas ratepayers** and **noncore customers**.
- Analyze, estimate, and predict the relationships of the **gas system to rate impacts** for **core** and **non-core gas customers**.
- The proposed economic study consists of four statistical and/or econometrics models.

Approach – Four Analyses

- Volatility Analysis.
- Factors that Motivate Natural Gas Storage Decisions in SoCalGas.
- The Impact of Natural Gas Storage on Ratepayers’ Gas Bills.
- The Impact of Tighter Gas Supply in SoCalGas System on Power Generation in the CAISO Territory.

Approach – Part 1: Volatility Analysis

- Objective and Approach:
  - Storage is used to **reduce** the economic impact of **fluctuations in natural gas prices** and thus reduces the volatility.
  - **Loss** of storage could **increase** core and noncore customers' **exposure** to market volatility. **Noncore** customers have been **unable** to **purchase** new **storage rights** in the primary storage market since **restrictions** on the use of **Aliso Canyon** were put in place.
  - Volatility tends to **increase** the **costs** of supplying and consuming **gas**.
  - **Quantifying** the **volatility of gas price. Explaining** the **behavior** of this **volatility** as function of other **variables.**

Approach – Part 1: Volatility Analysis(cont'd)

- **Volatility analysis** on prices of gas at the **SoCal Citygate** and **SoCal border**; and compare that volatility to volatility of gas prices in other relevant markets such as:
  - **PG&E Citygate.**
  - **Henry Hub.**
  - **San Juan Basin.**
  - **Permian Basin.**
- Volatility will be quantified as the **variation** in the **natural logarithm function** of the natural gas price (the log of price in period t over the log of price in period t-1: **return *=r(t, t-1) =ln (p(t)/p(t-1)))*** *).*
- If **more variation** is observed in the **SoCal Citygate** price and **SoCal border** post **Aliso incident**, ED will preform a **time series model** to study **the factors** impacting the **volatility** of **SoCal Citygate** and **SoCal border** prices.

Approach – Part 1: Volatility Analysis(cont'd)

- Is the **variation** due to **lack of storage**, **outages**, or **both**?
- Energy Division will evaluate the appropriate time series model. For example:

  $$\textbf{variance(return)=constant} + \boldsymbol{\beta}\mathbf{1} * \textbf{(lag of variance return)} + \boldsymbol{\beta}\mathbf{2} * \textbf{(storage inventory level)} + \boldsymbol{\beta}\mathbf{3} * \textbf{(pipeline available capacity)} + \boldsymbol{\beta}\mathbf{4} * (\textbf{seasons}) + \boldsymbol{\beta}\mathbf{5} * (\textbf{other variables}) + \boldsymbol{\varepsilon t}$$

  $\boldsymbol{\beta}$ ("beta") is a coefficient that estimates the marginal effect changing a variable would have on the outcome while holding the other variables constant.

- Other variables:
  - The customer imbalance in the SoCalGas system
  - Renewable Generation
  - Based on the parties discussion at the end of the presentation

Approach – Part 2: Factors that Motivate Natural Gas Storage Decisions in SoCalGas

- Objective and Approach:
  - Analyzing the **factors** influencing **SoCalGas Acquisition '**natural gas **storage decisions**.
  - Determine the **value** of storing gas in the **off season** for **high season use**.
  - Determine the **value** of having stored gas during **price spikes**.
  - Provide more **clarity** on the **pricing** of natural gas; and provide some **insight** to the **regulator** for better **planning** in the of short term.
  - Energy Division will study the **relationship** between **daily net injection volume** in SoCalGas gas storage facilities and **other variables** such as weather, capacity, spot price, futures price and other factors suggested by the parties.

Approach – Part 2: Factors that Motivate Natural Gas Storage Decisions in SoCalGas (cont'd)

- Energy Division proposes a time series model. For example:

  $$\textbf{daily net injection} = \textbf{constant} + \boldsymbol{\beta 1} * (\textbf{lag of net injection}) + \boldsymbol{\beta 2} * (\textbf{storage inventory level}) + \boldsymbol{\beta 3} * (\textbf{pipeline available capacity}) + \boldsymbol{\beta 4} * (\textbf{heating degree days}) + \boldsymbol{\beta 5} * (\textbf{cooling degree days}) + \boldsymbol{\beta 6} * (\textbf{binary indicator for gas price spike}) + \boldsymbol{\beta 7} * (\textbf{renewable generation in Southern CA}) + \boldsymbol{\beta 8} * (\textbf{price spread}) + \boldsymbol{\beta 9} * (\textbf{other variables}) + \boldsymbol{\varepsilon t}$$

- **Potential variables:**
  - Lag of net injection (lags are previous instances)
  - Pipeline available capacity
  - Beginning-of-the-day stock level
  - Day-of-week dummies

Approach – Part 2: Factors that Motivate Natural Gas Storage Decisions in SoCalGas (cont'd)

- Heating degree days(HDD) and cooling degree days(CDD) or seasons or months
- Operational flow order
- Price spread: future price- spot price
- Basis differential : SoCalborder daily spot price – Henry Hub spot price
- Gas price spike
- Renewable generation in Southern CA
- Other variables

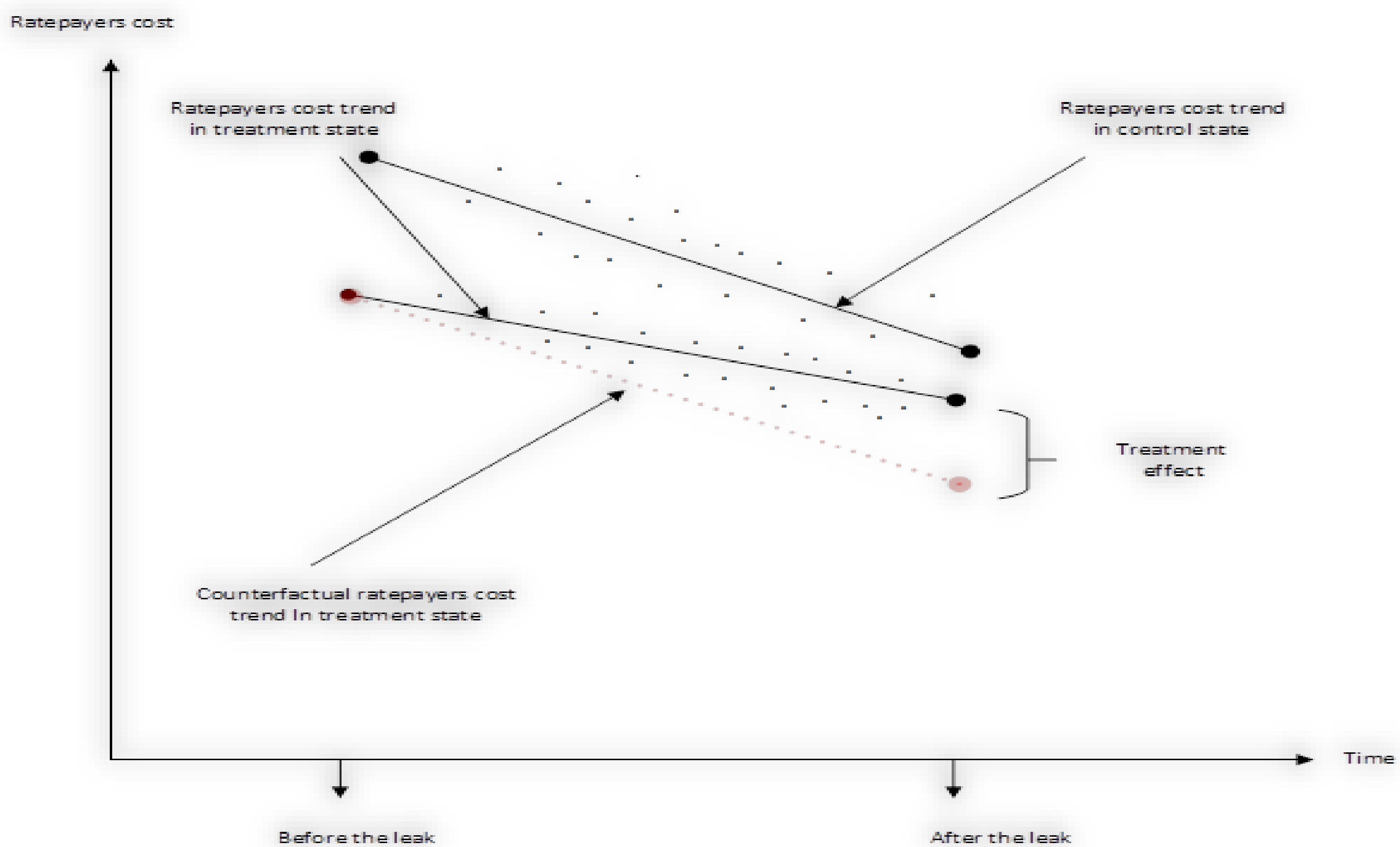
Approach – Part 3: The Impact of Natural Gas Storage on Ratepayers' Gas Bills

- Objective and Approach:
  - **Quantifying the effect of storage availability on ratepayers' gas bills.**
  - Energy Division proposes an econometrics technique called ***"*Difference in Differences**" to compare the ratepayers **monthly bill before** and **after** the Aliso Canyon **leak** using **panel data** (data collection over time and over the same individuals).
  - Energy Division staff will study **customer bills** for customers in **SoCalGas** and **PG&E** service areas with **similar zip code** including communities in Arvin, Bakersfield, Fellows, Fresno, Del Ray, Fowler, Paso Robles, Selma, Taft, Tehachapi, and Templeton.

Approach – Part 3: The Impact of Natural Gas Storage on Ratepayers' Gas Bills (cont'd)

- The basic idea: (B2 − B1) − (A2 − A1)
  - B is the **treatment group** (the study group with the exposure), **B1** is the treatment group **before the exposure** and **B2** is the treatment group **after the exposure**.
  - A is the **control group** (the comparison group without the exposure), **A1** is the control group **before the exposure** and **A2** is the control group **after the exposure**.
  - (B2 − B1) is the **difference in monthly bill after** vs **before** the Aliso Canyon **leak** for the **SoCalGas customers**. And, (A2 − A1) is the **difference in monthly bill after** vs **before** the Aliso Canyon **leak** for the PG&E customers.

Approach – Part 3: The Impact of Natural Gas Storage on Ratepayers' Gas Bills (cont'd)



Causal effects in the differences-in-differences model

Approach – Part 3: The Impact of Natural Gas Storage on Ratepayers' Gas Bills (cont'd)

- The difference will be estimated from a regression model:

  $$Yst = \beta 0 + \beta 1Ts + \beta 2PTt + \beta 3(Ts \times PTt) + \sum_{k=4}^{r} \beta kX + \varepsilon st$$

  - *Yst* the observed outcome in group s and period t. In this case, it is the individual ratepayer's monthly bill cost.
  - $\beta 3$ is coefficient of the **treatment effect which is the coefficient of interest**. And, the estimate of $\beta 3$ is **identical to the double difference**: **(B2 −B1) −(A2 −A1)**.
  - *Ts* is a dummy variable set to 1 if the observation is from the "treatment" group in either time period.
  - *PTt* is a dummy variable set to 1 if the observation is from the post treatment period in either group.

Approach – Part 3: The Impact of Natural Gas Storage on Ratepayers' Gas Bills (cont'd)

- $\sum_{k=4}^{r} \beta kX$**:** X is a set of the explanatory variables and βks are the coefficients to be estimated. This set of the explanatory variables could include variable for pipeline capacity and, Operational flow order and other variables.

- εst is an error term, $\beta 0$ is the intercept, $\beta 1$ is the coefficient of the *Ts* and $\beta 2$ is the coefficient of *PTt*.

➢ In addition to DID analysis, ED will analyze **monthly data** from **SoCalGas rate schedules**. ED will look at the historical share of retail rate for gas and non-gas charge by customer classes: **Gas charge/Total charge** and **NonGas charge/Total charge**.

Approach – Part 4: The Impact of Tighter Gas Supply in SoCalGas System on Power Generation in the CAISO Territory

- Objective and Approach:
  - **Constrained** gas **supply** from Aliso Canyon, can lead to an **increase** in the natural gas price in Southern California.
  - The price could make **gas-based generation more expensive** in the **south** with **respect to** the **north** and **shift** generation from the SoCal system to Northern California.
  - These dynamics could mean higher energy costs in the California ISO markets because of the **congestion on the transmission network**.
- Assessing the **difference in dispatch** and **congestion** in the **CAISO** territory.

Approach – Part 4: The Impact of Tighter Gas Supply in SoCalGas System on Power Generation in the CAISO Territory(cont’d)

- **Implied Heat Rate**:
  - $$\textbf{Implied Heat Rate} = \frac{\textbf{The day–ahead electric price}}{\textbf{The daily natural gas price}}$$
  - It will be reported along side with **net load**.
- **Congestion Rent Assessment**:
  - **Congestion rent revenue from generation =(marginal congestion component of the LMP)*(the scheduled generation)**
  - It will be reported along side with **the electric imports from outside California.**
- Energy Division will use Northern and Southern California day-ahead market **electric price** using North of Path 15 (**NP15**) and South of Path 15 (**SP15**), **generation** data based on the transmission access charge area (**TAC**) for both the implied heat rate and congestion rent ; and **PG&E Citygate** and **SoCalGas Citygate** (and **SoCalGas border**) for natural gas prices.

Data Sources

Datasets	Data Source
Daily storage inventory level by storage field in SoCalGas system	Data request (DR)
Daily cooling and heating degree days	DR
Daily and monthly gas prices for: SoCalGas Citygate, PG&E Citygate, SoCalGas border, San Juan, Permian and Henry Hub	Platts or NGI
Curtailment volume in SoCalGas system	DR
Operational flow order	DR and Envoy
Future price	EIA and DR
Future price from the gas market fundamental model	DR
Pipeline available capacity and outages	DR and Envoy
Bill data	DR from SoCalGas and PG&E
Low income households bill data	DR from SoCalGas and PG&E
The day-ahead electric price and generation	OASIS

Items in red indicate confidential data

Economic Modeling Outputs

- Volatility plots for different markets, other plots such as the volatility and SoCal system average temperatures over time, and, the volatility and SoCal storage inventory over time.
- Regression **estimates and prediction table** for **volatility** (if necessary).
- Regression **estimates table** for the factors that Motivate Natural Gas **Storage Decisions**, and, relevant plots.
- The **Difference in Differences** model **estimates table**, and, relevant plots.
- Summary statistics table for historical bill data for **CARE** and **non-CARE** customers:
  - The mean and standard deviation of baseline price, average price, marginal price, gas consumption and total bill.
- Plots and tables for **Implied Heat Rate and Congestion Rent Assessment**.

Economic Modeling – Themes in Informal Comments

EDF: Use NYMEX Forwards adjusted for negative basis to California.

CPUC: Staff is planning to use blended price. Nymex price and price from the gas market fundamental model.

SCPOU: Explain why Economic Modeling is limited to CAISO and not LADWP and IID.

CPUC: Staff will use CAISO data because CAISO data is publically available and CAISO represents the majority electricity market in CA.

MEM: Implied Heat Rate should be assessed on an hourly basis using hourly day-ahead LMP prices from The CAISO Open Access Same-time Information System (OASIS).

CPUC: Agrees, we are considering using LMP hourly data.

Economic Modeling – Themes in Informal Comments

CAISO: Concerns about using historical CAISO OASIS pricing information to determine the potential effects in the future as well as the degree of linearity of the comparison.

CPUC: Staff are not expecting all the variables to be linear; we will make the necessary transformations to fit a good model. In terms of historical CAISO OASIS pricing information, we are open to consider any other proposed data set if you have something in mind?

TURN: Implied heat rates in Economic Modeling should consider CAISO GHG bidding and pricing rules, or explain why not.

CPUC: Staff agrees, we are considering it.

Economic Modeling – Themes in Informal Comments

SoCalGas: Economic impacts are not limited to gas and electricity; higher gas and electricity prices will reduce economic activity in Southern California.

CPUC: Beyond the scope of the questions we are trying to answer.

SoCalGas: Use a model that is capable of projecting electricity prices with and without Aliso Canyon, such as PLEXOS.

CPUC: Staff plans to use our current Production Cost Model (PCM), SERVM. It is a PCM being used by CPUC Energy Division staff in serval proceedings such as IRP and RA. SERVM will help us determine production costs and electricity costs under a range of scenarios and variables.

Economic Modeling – Themes in Informal Comments

County of Los Angeles: New regression equations for: SoCal natural gas price, SP15 price, and bill impact of Aliso Canyon's closure.

A) The SoCal natural gas price regression:
To measure the impact of Aliso Canyon's closure on the SoCal gas price.

B) The SP15 electricity price regression:
To estimate the effect of Aliso Canyon's impact on the SP15 DAM price.

C) The impact on the SP15 electricity price:
Calculated based on part(A) and (B).

D) The bill impact of Aliso Canyon's closure:
Estimate the impact of Aliso Canyon's closure on a natural gas bill based on measures from part (A) and use -0.10 own-price elasticity of retail consumption for natural gas and -0.05 for electricity.

Economic Modeling – Themes in Informal Comments

CPUC Staff observations:

Part A)

- Maybe more variables need to be included especially weather and outages.

Part B) and C):

- Probably a production cost model such as SERVM will be better suited to address both parts.

Part D):

- The elasticity is estimated at the aggregate level. Also, assumes elasticity is the same across all income classes and seasons.

- Assumes the bill impact is only due to change in the gas price.

In general:

- Maybe the storage should be reflected in the future price or contracts since SoCalGas purchases very little on daily spot market.

Economic Modeling – Discussion Points

- Are there any other inputs or assumptions, datasets that should be considered?
- Which daily gas spot price dataset is appropriate (Natural Gas Intelligence(NGI) vs Platts)?
- Should Energy Division separately analyze on peak and off peak hours in the implied heat rate analysis?

Next Steps

Liane Randolph

Commissioner

Thank you!
For Additional Information please visit the CPUC Aliso Canyon webpage:

http://cpuc.ca.gov/aliso/

and the investigation webpage:

http://www.cpuc.ca.gov/AlisoOII/