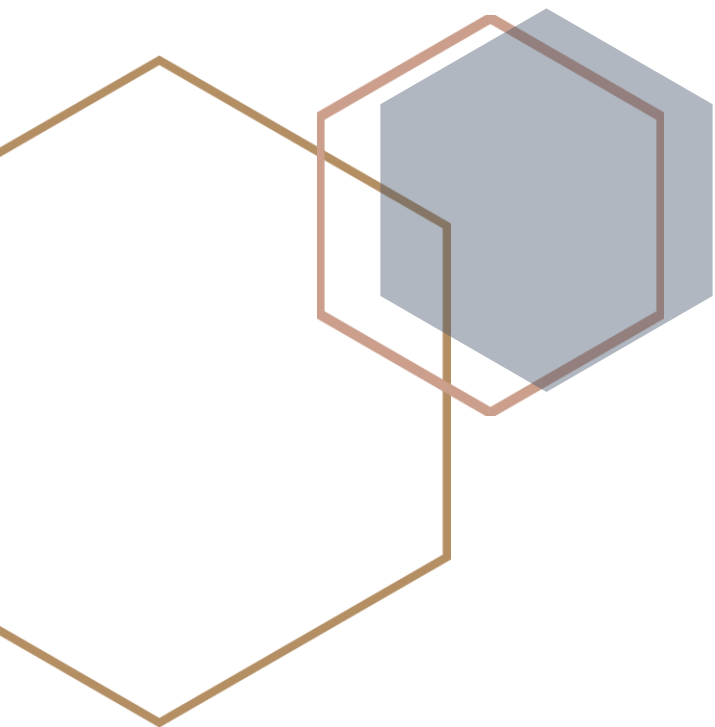




# SCENARIOS FRAMEWORK I.17-02-002

Prepared by CPUC Energy Division

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## Introduction

In this document, the California Public Utility Commission's (CPUC or Commission) Energy Division (ED) updates its June 26, 2017 framework for conducting the modeling studies needed to inform the Ordering Instituting Investigation (OII) 17-02-002. Pursuant to statutory mandate, the OII will determine the feasibility of minimizing or eliminating use of the Aliso Canyon natural gas storage facility (Aliso) while still maintaining energy and electric reliability for the region. To help make this determination, the modeling studies will explore two questions; first, whether Aliso is needed for reliability, and second, what the impact on costs would be if Aliso were to be closed or operated at a level of inventory lower than historic norms.

This final version of the Scenarios Framework builds on the comments received on the previous two draft versions, both in written form and at the August 1, 2017 and July 31, 2018 workshops. The section on hydraulic modeling also draws on Energy Division's consultation with Los Alamos National Laboratory (Los Alamos).

Parties to the proceeding will have the opportunity to make formal comments on this framework. Formal comments are due by October 9, 2018, and should be emailed to the service list of Investigation (I.) 17-02-002, filed formally, and sent to Commission staff at [AlisoCanyonOII@cpuc.ca.gov](mailto:AlisoCanyonOII@cpuc.ca.gov).

## Background

A major gas leak was discovered at the Southern California Gas Company's (SoCalGas) Aliso Canyon natural gas storage facility on October 23, 2015. On January 6, 2016, the governor ordered SoCalGas to maximize withdrawals from Aliso to reduce the pressure in the facility. The CPUC subsequently required SoCalGas to leave 15 Billion cubic feet (Bcf) of working gas in the facility that could be withdrawn to maintain reliability. On May 10, 2016, Senate Bill (SB) 380 was approved. Among other things, the bill:

1. Prohibited injection into Aliso until a safety review was completed and certified by the Division of Oil, Gas, and Geothermal Resources (DOGGR) with concurrence from the CPUC;
2. Required DOGGR to set the maximum and minimum reservoir pressure;
3. Charged the CPUC with determining the range of working gas necessary to ensure safety and reliability and just and reasonable rates in the short term; and
4. Required the CPUC to open a proceeding to determine the feasibility of minimizing or eliminating use of Aliso over the long term while still maintaining energy and electric reliability for the region.

On February 9, 2017, the CPUC opened an Order Instituting Investigation pursuant to SB 380. The proceeding is structured to take place in two phases. In Phase 1, the Commission will undertake a comprehensive effort to develop assumptions and scenarios to evaluate the impact of reducing or eliminating the use of Aliso. The intent of Phase 1 is to involve all interested parties in developing a transparent and vetted list of assumptions and scenarios to be modeled in Phase 2. Phase 1 will be resolved by the issuance of an Assigned Commissioner's Ruling providing guidance on the assumptions and scenarios that will be evaluated in Phase 2. In Phase 2, the Commission will conduct the analyses agreed to in Phase 1 and evaluate the results. These results will inform the Commission's decision on the appropriate use of the storage field.

On July 19, 2017, DOGGR certified, and the Executive Director of the Commission concurred, that the required inspections and safety improvements had been completed and injections could resume. DOGGR authorized Aliso operations at pressures between a minimum of 1,080 pounds per square inch absolute (psia) and a maximum of 2,926 pounds psia.<sup>1</sup> These pressures translate into an allowable inventory of working gas that ranges from 0 Bcf to approximately 68.6 Bcf.<sup>2</sup> Any decision about Aliso inventory ultimately reached in I.17-02-002 must fall within the DOGGR-approved range.

### Modeling Overview

Energy Division plans to undertake three studies to inform this investigation: hydraulic modeling, production cost modeling, and economic modeling. The studies are intended to estimate how reducing or eliminating use of Aliso would impact gas and electric reliability, electric costs and reliability, and natural gas commodity costs.

Energy Division will conduct the production cost modeling and economic modeling in-house and has hired Los Alamos to provide technical assistance and oversee the hydraulic modeling study to be performed by SoCalGas. Los Alamos has overseen hydraulic modeling performed by SoCalGas for previous versions of the Aliso Canyon Technical Assessments.<sup>3</sup> Los Alamos has assisted Energy Division in updating the

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<sup>1</sup>The findings can be found here:

[http://www.conservation.ca.gov/dog/Documents/Aliso/Enclosure1\\_2017.7.19\\_Updated%20Comprehensive%20Safety%20Review%20Findings.pdf](http://www.conservation.ca.gov/dog/Documents/Aliso/Enclosure1_2017.7.19_Updated%20Comprehensive%20Safety%20Review%20Findings.pdf)

<sup>2</sup> This figure is based on an April 19, 2018, email from DOGGR to the CPUC.

<sup>3</sup> The Technical Assessments were created by the Aliso Canyon Technical Assessment Group, which consists of the CPUC, the California Energy Commission, the California Independent

hydraulic modeling section of this Framework. Los Alamos will continue to work with Energy Division to provide expertise on the final scenarios to be modeled and assumptions about the gas system. Los Alamos will also review the technical interpretation of hydraulic modeling scenarios to be performed by SoCalGas and prepare recommended modifications to SoCalGas modeling.

## Hydraulic Modeling: Introduction

In principle, analysis of the coupled electric grid-natural gas system in Southern California requires a fully integrated, intra-day model of the two systems. This type of integrated modeling is not commercially available and is not feasible to develop in the time available to complete this investigation. Instead, Energy Division staff proposes constructing a scenario framework to evaluate key reliability and feasibility requirements of the individual natural gas and electric power systems and to define how the output of each infrastructure model is used to develop boundary conditions or inputs for the other model.

Historically, Aliso has played a key role relative to system reliability and gas prices.

- 1) Gas system reliability:
  - a) When daily or hourly gas demand is higher than the pipeline flowing capacity, gas is withdrawn from storage at Aliso to serve the demand that exceeds the flowing supplies. This functionality is possible because Aliso is close to the major gas load centers.
  - b) When daily gas demand is highly variable, for example when electric generation is re-dispatched in the California Independent System Operator (CAISO) hour-ahead or real time market, rapid increases or decreases in the hourly gas load can cause large pipeline pressure swings. Withdrawals from or injections into Aliso can be used to mitigate these pressure swings and keep the pressure within operating bounds. This is a critical requirement for maintaining safety and avoiding excessively low pressures from limiting gas flows.
- 2) Price Arbitrage:

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System Operator, and the Los Angeles Department of Water and Power and began in response to the Aliso gas leak. All previous versions of the Technical Assessments can be found at: <http://cpuc.ca.gov/alisoassessments/>.

- a) The traditional role of gas storage at Aliso Canyon is to leverage seasonal variations in gas prices to store significant quantities of gas near the load centers while gas prices are low and to release that gas to customers during periods of high prices.

For the gas reliability role above (1), hydraulics and best practices seem to govern the system operation and reliability more than economics, i.e. if demand exceeds supply, acquiring cheaper or more expensive gas does not obviate the reliability need for withdrawals from underground storage. The same can be said about pressure swings and fluctuations. However, it is possible that a nearby underground storage facility such as PDR or Honor Rancho or other solutions may be able to substitute for the reliability role that Aliso historically provides.

For Aliso's traditional gas price arbitrage role, since there is no coupling or optimization between the hydraulic simulation and gas prices, the ongoing practice (in both modeling of the system as well as operating the system) is to manually decide on mitigation or operational actions. Experienced operators already know which operational actions should be taken to avoid under- or over-pressurization. Within this context, and for the purposes of this investigation, it appears that economics do not affect much of the hydraulic simulation *near* the demand nodes if the total transmission capacity of each zone is held close to its zonal firm access as provided in schedule G-BTS.<sup>4</sup>

Within this investigation, the hydraulic modeling will, for the most part, be independent of the econometric analysis and vice versa. An exception could be made if the need for drastic changes is revealed, such as maximizing the gas flow through uncommon receipt points or gas sources. For such cases, the resulting gas-electric system characteristics may be further analyzed for impacts on the cost of energy services.

### Hydraulic Modeling: Assessment Framework

The hydraulic modeling of the gas system is composed of two assessments – a Reliability Assessment and a Feasibility Assessment. The fundamental difference between the two assessments is that the Reliability Assessment aims to analyze the gas system under peak gas demand conditions on a given day (as previously defined by the reliability

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<sup>4</sup> The schedule can be found here: <https://www.socalgas.com/regulatory/tariffs/tm2/pdf/G-BTS.pdf>

standard), while the feasibility assessment aims to analyze the gas system under typical demand conditions throughout a whole year in order to affirm that meeting peak demand is “feasible” throughout a typical year. The Feasibility Assessment will determine whether the results of the Reliability Assessment are feasible in a typical year, particularly in terms of the required minimum withdrawal capacities from underground storage facilities. The figure below is a simple illustration of the framework.



*Figure 1: Hydraulic Modeling Steps*

CPUC staff proposes that the analysis takes a graded approach. In a graded approach, a full monthly analysis will be completed for 2020 to provide near term gas storage targets. In later years, i.e. 2025 (five years) and 2030 (10 years), the Assessment will be run for the peak winter and peak summer months only. This is primarily because of the higher uncertainty in the forecasts for the years 2025 and 2030. A description of both assessments follows.

## Hydraulic Modeling: The Reliability Assessment

### Reliability Assessment: Introduction

The reliability assessment focuses on determining the monthly minimum level of gas in underground storage (i.e. a monthly storage schedule) needed to maintain the reliability of both energy systems (electricity and gas) and to maintain just and reasonable energy rates.

In this assessment, preference within the model is given to operations of non-Aliso storage facilities as a means to determine the minimum need for gas storage inventory at Aliso Canyon. If the minimum level of inventory is found to be zero for all months, then it will be possible to conclude that closing Aliso would not affect energy system reliability. In the following sections, the reliability standard is introduced followed by a description of the modeling inputs and assumptions and the desired outputs.



## Reliability Assessment: The Reliability Standard

The Reliability Assessment determines whether the CPUC's reliability standards can be met.<sup>5</sup> Overall, the natural gas system must maintain the ability to deliver the required gas to the delivery nodes at a minimum set pressure without interruption, unless specified otherwise by the reliability standard (e.g. noncore gas curtailments).

The 1-in-10-year and 1-in-35-year standards (also termed peak and extreme peak days respectively) represent extreme demand scenarios to which the gas system is planned. Each of these standards define two important conditions for the SoCalGas natural gas system:

- The required performance of the natural gas delivery system; and
- The operational actions that are allowable to achieve this performance.<sup>6</sup>

The full implementation of all operational actions is likely to stress other systems connected to the SoCalGas system, which is not a desirable outcome. However, the concept of designing to, or analysis of, a reliability standard assumes that this cascading stress on the connected system is acceptable. With this understanding, the Reliability Assessment of the SoCalGas system will use full implementation of all allowable operational actions to achieve the required system performance.

The assessment of the reliability standards is done using simulation of the infrastructure system under the conditions of the 1-in-10 peak day design standard. This should not be confused with analysis of a historical operating day. In the real world, the system operators do not have the foresight into upcoming conditions available in the simulation. The assessment of the reliability standard should not be interpreted as an "operational playbook" that informs the system operators of each action they should take. In actual operations, even in a scenario similar to that defined in the reliability standard, the system operators may take additional actions, not take actions that were taken in the analysis, or implement actions in a different order.

These differences between real-world operations and the simulation of the reliability standard may be important to the actual performance of the SoCalGas system and to the

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<sup>5</sup> See D.02-11-073 and D.06-09-039 for the establishment of reliability standards

<sup>6</sup> All operational actions allowable will abide by CPUC approved rules:  
<https://www.socalgas.com/regulatory/tariffs/tariffs-rules.shtml>

cascading stress applied to connected systems. The Reliability Assessment only shows whether it is *possible* to achieve the minimum gas system performance standard without implementing operational actions beyond that which is allowable by the standard.

Among the operational actions that are allowed within the reliability standards are gas curtailments, which are described next.

The natural gas system is held to two related reliability standards that differ in the severity of the gas loading and the flexibility in curtailments. For the peak (1-in-10) and extreme peak (1-in-35) day conditions, the maximum allowable gas load curtailment is defined for each constituent as follows.

- *Core gas load*  
No curtailments are allowed for either the 1-in-10 or 1-in-35 standard.
- *Noncore, electric gas load*  
For the 1-in-10 standard, no curtailments are allowed. This implies that the electric production cost model is unconstrained by gas availability. For the 1-in-35 standard, electric gas load is fully curtailed to zero. This implies that the electric PCM should not allow any consumption of natural gas for electric generation under this scenario
- *Noncore, non-electric gas load*  
For the 1-in-10 standard, no curtailments are allowed. For the 1-in-35 standard, full curtailment to zero, while maintaining certain carve outs as specified in Rule 23.

### Reliability Assessment: Steady and Transient Simulations

In order to perform the reliability assessment on the natural gas network system, multiple hydraulic simulations must be run in the modeling software, Synergi. For each hydraulic simulation, first a steady-state simulation must be run and a steady-state solution must be established, i.e. a solution where fluid and flow properties are not varying with time (because demand is assumed constant). Once a successful steady-state solution is established, then a transient simulation can be run, where the flow properties are allowed to vary with time (to meet variable gas demand). In other words, the steady-state solution provides the initial condition from which the transient simulation can start, while the transient simulation investigates the performance (pressure and flow) of the natural gas pipeline network under varying gas demand.

Whether it is a steady-state simulation or a transient simulation, the natural gas pipeline network parameters will be setup in Synergi. This includes pipeline properties (e.g. lengths, diameters, locations, friction parameters, etc.), fluid properties (natural gas density, temperature, compressibility, etc.), compressor stations (locations and performance characteristics), and flow control valves and pressure regulators (locations and characteristics). Most of these properties do not vary from one simulation to the next. However, the most important properties that can vary are valve and compressor settings based on the flow configuration (e.g. which receipt points are scheduled to receive gas or whether a certain storage facility is set to inject or withdraw). All this data is stored in a “case file” by the modeling software and will be reported to the CPUC and Los Alamos where it will be reviewed and investigated.

When the pipeline network is fully described, the next step is to prescribe what is to happen at the boundaries of the pipeline network (termed “boundary conditions”). This is the flow at the delivery nodes (demand), the pressure (or flows) at the various receipt points (scheduled receipts), and the valve configuration along the pipelines and at the storage facilities (withdrawing or injecting). It is these boundary conditions that dictate the required inputs needed to execute a hydraulic simulation. These boundary conditions will vary based on which reliability standard is being modeled. Boundary conditions translate to a few “operational” or “real-life” inputs such as gas demand profiles and gas curtailments, which will be discussed in the next section. Once a transient state and boundary conditions are established, the next step is to set up variables.

### Reliability Assessment: Simulations Inputs

To perform the Reliability Assessment, several inputs are required by the hydraulic simulations, which vary based upon which of the two reliability standards is being modeled. These inputs include the natural gas demand profiles, gas curtailment standards, non-Aliso gas storage facility maximum withdrawal capabilities, achievable flowing gas supplies at the pipeline receipt points, and pipeline or storage outages that may affect the hourly send-out of the gas system. These inputs and assumptions are described below.

#### 1. Hourly gas load profiles

For the natural gas system, hourly load (demand) profiles must be defined for each type of load for both reliability standards.

- *Core gas load*

Since historical hourly data is not available for peak (1-in-10) or extreme peak (1-in-35) core gas demand conditions for a suitable number of historical years, an approximation must be made and a “synthetic” profile must be derived. CPUC staff will derive peak demand profile *shapes* from smart meter data obtained for at least a whole calendar year. Load profile shapes will then be scaled up based on the forecasted peak and extreme peak of the simulated future years, which will be obtained from the most recent California Gas Report, subject to verification by the CPUC.

To generate the shape of gas demand (*not* the peak level) CPUC staff will collect smart meter data for a whole year for each zip code served by the utility company. Then, for each month of the year, the day that corresponds to the highest total daily core gas demand will be selected as a representative shape for the extreme peak demand (i.e. 1-in-35). In addition, the third highest daily demand will be selected as a representative shape for the peak demand (i.e. 1-in-10 or 90 percentile level).<sup>7</sup> Those shapes will then be scaled upwards to match the forecasted peak levels from the California Gas Report for the appropriate future study years.

Upon analysis of the profiles, the CPUC may keep all 24 profile shapes (one per month for each of the extreme peak and peak days per zip code). If shapes are strongly similar for a whole season or across many months, profile shapes may be merged or dropped, but no less than four profile shapes will be retained and loaded into the hydraulic model representing both peak and extreme peak shapes for the summer and winter seasons. The most important shape metric is the maximum ramp rate (mathematically termed maximum slope or gradient), which translates to sudden increases in gas demand, and will therefore affect the performance of the pipeline network.

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<sup>7</sup> Staff acknowledges that recent years have not been as extreme in temperature, but this approach is needed to derive the profile shape. The 90<sup>th</sup> percentile represents the chance of a 1-in-10 peak demand.

- *Noncore, electric gas load*

Hourly noncore, electric load will be computed from a production cost model (PCM). Depending on the reliability standard being modeled, the PCM will model one of two cases. For the peak (1-in-10) day, hourly load profiles will be computed based on the economically optimal production of electricity with no gas supply constraints and meeting minimum NERC reliability standards (Unconstrained Gas scenario). For the extreme peak (1-in-35) day, the PCM will perform an out-of-merit production cost model that reduces gas consumption to the minimum to meet NERC reliability standards (Constrained Gas scenario). Details about the PCM are discussed in the PCM section.

- *Noncore, non-electric gas load*

For both reliability standards (1-in-10 and 1-in-35), the gas demand for noncore, non-electric customers will be obtained directly from SoCalGas.

## 2. Gas Storage Facilities

The natural gas pipeline and storage system is modeled for the peak and extreme peak days, and the required hourly withdrawals from underground storage facilities are determined accordingly. Withdrawals from non-Aliso facilities are utilized first. If non-Aliso facilities cannot support the total load, then withdrawals from Aliso are used to serve the remaining gas load that is not allowed to be curtailed in the scenario. Details about the modeling approach of each storage facility is described below.

- *Playa Del Rey (PDR)*

The PDR storage field has relatively small storage capacity, but it is key to gas control operations and the reliability of gas supply in the Los Angeles Basin during a day of peak gas send-out. These storage field operations are reflected in both the 2017 summer system capacity study and in actual gas control operations. PDR has a relatively short refill time (approximately a few days). Therefore, PDR can be considered at

maximum storage capacity and can supply the corresponding maximum withdrawal rates on any peak day.<sup>8</sup>

- *La Goleta*

The La Goleta storage field has access to limited pipeline transportation capacity. On a peak day, pipeline constraints limit the ability of this storage field to support peak gas loads to the south in the Los Angeles Basin. This field is used in more of a “baseload” manner to support the overall recovery of system-wide “linepack”.<sup>9</sup> Any peaking storage withdrawal from this field is used primarily to support peak gas loads in the coastal Santa Barbara and Ventura county region of the SoCalGas pipeline system. This use is reflected in both the 2017 summer system capacity study and in actual gas control operations. Because of the pipeline restrictions near La Goleta, assuming that La Goleta is at maximum storage capacity and maximum withdrawal rates on any peak day, gas flows will be limited by pipeline transportation constraints.

- *Honor Rancho*

Compared to La Goleta, the Honor Rancho storage field has better access to pipeline transportation capacity into the Los Angeles Basin. In the absence of Aliso Canyon, it is key to supporting peak gas loads in the Los Angeles Basin. However, the full withdrawal capacity of Honor Rancho may not be achievable because it competes with gas receipts from Wheeler Ridge for pipeline transportation capacity. If both Honor Rancho storage withdrawal and Wheeler Ridge receipts are maximized, pipeline pressure would exceed the maximum allowable operating pressure, which would violate safety and compliance requirements. Under the stressed conditions of the Reliability Assessment, it is reasonable to assume that the combination of Wheeler Ridge receipts and Honor Rancho withdrawals will always be pipeline transportation limited and the available aggregate supply from these sources is determined by this limit.

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<sup>8</sup> If alternative scenarios are considered that span more than one day, the availability of maximum withdrawal rates at PDR come into question, and this assumption should be revisited.

<sup>9</sup> Linepack refers to storing gas in the pipeline as opposed to within a storage facility.

- *Aliso Canyon*

The Reliability Assessment is computing the required withdrawals from Aliso. Therefore, no assumptions about this field are required. Since the modeler has to manually specify the configuration of valves or whether the storage facility is set to inject or withdraw, the first step will be to assume “closed” valves or “zero” injections and withdrawals. If the simulation fails with Aliso set to zero, then the required Aliso withdrawal rate will be computed.

### 3. **Flowing Gas Supplies**

Under the stressed conditions of the Reliability Assessment, it is anticipated that the flowing supplies at the receipt points will be maximized to minimize the withdrawals from storage, including Aliso. Hydraulic modeling can identify the maximum gas supply that could be scheduled into the SoCalGas pipeline system. Gas scheduling occurs in advance of gas burn; therefore, gas system operators may need to make real-time adjustments. However, in real-time operations, and due to restrictions on pipelines, outages, or limitations on injection capacities, the total transmission zone firm access (Schedule G-BTS) may not be achievable.

A preliminary analysis of the historical data of the zonal transmission capacity from January 2014 to August 2018 reveals the following trends:

- In 2014, the Southern Zone had an average transmission capacity of about 60% of its nominal (pipeline rated) capacity. The average capacity of the Southern Zone increased to about 65% in the 2016-2018 period. During the 2016-2018 period, there was a 9% chance that the zonal transmission capacity would be at or above 85%.
- In 2014, the Northern Zone had an average transmission capacity of roughly 75% of its nominal capacity. The average capacity has been declining, reaching about 50% in the 2017-2018 period. This appears to be due to sustained pipelines outages and restrictions in the Northern Zone. However, for the period from January 2014 to July 2015, there was a 20% chance that the zonal transmission capacity would be at or above 85%. During this same period, the zonal transmission capacity was above 95% for 3% of the days.
- For the 2014-2018 period, the Wheeler Ridge zone had a chance of 76% of operating at or above 85% of its nominal capacity and a 40% chance of operating at full nominal capacity.

Since the reliability standards investigate 1-in-10 and 1-in-35 demand conditions (which correspond to approximately a 10% and a 3% chance), and based on the numbers summarized above, it appears reasonable to use the following assumptions about the zonal capacity for the hydraulic modeling:

- Southern Zone 85% of its capacity during peak and extreme peak days.
- Northern Zone: 85% of its capacity during peak and extreme peak days.
- Wheeler Ridge Zone: 100% of its capacity during peak and extreme peak days.

The capacities percentage above may be revised by the CPUC upon further analysis of the data especially when taking into consideration that the balancing rules changed at the end of 2015.

#### 4. Outages

Both pipeline and storage outages can significantly impact the ability of the natural gas system to serve load on peak days. The months with the most severe operating conditions are well known, and planned outages can usually be scheduled to occur outside of these months. However, unplanned outages are frequent enough that they must be accounted for in the gas system modeling for the Reliability Assessment. A key factor is the number of concurrent unplanned outages on a peak day, the location of these outages, and the severity of the outages. For the Reliability Assessment, we propose that the 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.

The determination of the plausible unplanned pipeline and storage outage events should be carried out using historical records. A related analysis was carried out by SoCalGas and reviewed by the CPUC, the California Energy Commission (CEC), the California Independent System Operator (CAISO), and the Los Angeles Department of Water and Power (LADWP) in the April 2016 Aliso Canyon Risk Assessment Technical Report.<sup>10</sup> Table 3 of the report summarizes

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<sup>10</sup> Aliso Canyon Risk Assessment Technical Report, April 2016 version:

[http://www.energy.ca.gov/2016\\_energypolicy/documents/2016-04-08\\_joint\\_agency\\_workshop/Aliso\\_Canyon\\_Risk\\_Assessment\\_Technical\\_Report.pdf](http://www.energy.ca.gov/2016_energypolicy/documents/2016-04-08_joint_agency_workshop/Aliso_Canyon_Risk_Assessment_Technical_Report.pdf)



the calculations carried out to determine the range of estimated days the SoCalGas and SDG&E system will be under significant stress.

Under the stressed conditions of the Reliability Assessment, the impact of different unplanned outages can be estimated and ranked using the engineering judgement developed in Section 2.5 of the Independent Review of the Southern California Gas Hydraulic Modeling performed for the Summer 2017 Assessment. The discussion from that review is incorporated below.

The logic of the Reliability Assessment suggests that unplanned outages should first be applied at non-Aliso components:

- If the Reliability Assessment concludes that withdrawals from Aliso Canyon are not required, then the analysis is complete.
- If the Reliability Assessment concludes that withdrawals from Aliso Canyon are required, then the impact of the largest plausible unplanned outage at Aliso Canyon must be assessed. Based on the required Aliso withdrawal rate:
  - If the largest plausible Aliso Canyon unplanned outage is smaller than the impact on gas delivery from the largest plausible non-Aliso outage, then the non-Aliso outage dominates. The analysis is complete.
  - If the largest plausible Aliso Canyon unplanned outage is larger than the impact on gas delivery from the largest plausible non-Aliso outage, the Aliso outage dominates. The Aliso outage is imposed, and the non-Aliso outage removed when assessing the Aliso Canyon minimum required storage inventory to support the minimum required injections from Aliso Canyon.

Another aspect of the outages is related to the transmission zone capacity discussed above, where CPUC staff suggests using 85% of the zonal nominal capacity based on historical data. It is possible that this percentage is tied to historical pipeline outages (rather than injection rate limitations or low gas demand). More outages would translate to historically lower utilization of the zonal capacity. CPUC staff will investigate the impact of different types of outages on the zonal capacity. Staff may revise may revise the zonal utilization based on findings.

The CPUC proposes a general approach similar to that in the April 2016 Technical Assessment<sup>11</sup> with the following general guidelines:

- The highest impact unplanned outage should be determined using historical data rather than coming up with hypothetical unplanned outages.
- The selected plausible unplanned outage should not have a frequency of less than 10% when evaluating the 1-in-10 reliability standard.
- The selected plausible unplanned outage should not have a frequency of less than 3% when evaluating the 1-in-35 reliability standard.

### Reliability Assessment: Simulations Outputs

The hydraulic simulation outputs the required hourly withdrawals from non-Aliso and, if needed, Aliso gas storage facilities. The Reliability Assessment gives priority to withdrawals at non-Aliso facilities in order to minimize or eliminate usage of the Aliso facility. A hydraulic simulation is considered successful if:

- The pressure at all demand nodes is held above the minimum required pressure at these demand points for the duration of the simulation.
- All facilities must operate within established capacities (i.e. demand must be met).
- The maximum pressure does not exceed the Maximum Allowable Operating Pressure (MAOP) at any point or time.<sup>12</sup>
- “Linepack” is restored, i.e. the amount of gas present in the pipeline at the end of the simulation is the equal to the amount as at the beginning of the simulation
- Storage fields can maintain the required withdrawal (or injection) capacity (mass flow rate).

After a successful simulation, facility-specific curves of maximum withdrawal rate versus gas storage are used to convert the required gas storage withdraw rates at each facility to a minimum gas storage volume requirement to maintain reliability during the

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<sup>11</sup> Aliso Canyon Risk Assessment Technical Report, April 2016 version:

[http://www.energy.ca.gov/2016\\_energypolicy/documents/2016-04-](http://www.energy.ca.gov/2016_energypolicy/documents/2016-04-08_joint_agency_workshop/Aliso_Canyon_Risk_Assessment_Technical_Report.pdf)

[08\\_joint\\_agency\\_workshop/Aliso\\_Canyon\\_Risk\\_Assessment\\_Technical\\_Report.pdf](http://www.energy.ca.gov/2016_energypolicy/documents/2016-04-08_joint_agency_workshop/Aliso_Canyon_Risk_Assessment_Technical_Report.pdf)

<sup>12</sup> MAOP is defined and set by 49 CFR 192.

scenario. At each facility except for PDR,<sup>13</sup> this required hourly withdrawal rate is converted into a required gas storage volume using the maximum withdrawal rate curves generated through a calibration process carried out by SoCalGas during operation of these facilities.<sup>14</sup>

In certain months of the year when the monthly peak day does not highly stress the gas system, the required withdrawals at Aliso may be zero, and the required withdrawal rates at La Goleta and Honor Rancho may fall below the assumed available minimum withdrawal capacity for each storage facility, discussed above. This does not violate the assumptions of the Reliability Assessment. It provides the relevant data on the required withdrawals while minimizing the need for the Aliso facility for reliability.

For each month, either the 1-in-10-year analysis or the 1-in-35-year analysis will result in a higher withdrawal (compared to typical or average demand) from the underground gas storage fields. The higher of the two is used to determine the minimum gas storage requirement or a “gas schedule.” By the end of the Reliability Assessment, the analysis will arrive at a “Minimum Gas Storage Schedule” for each month studied (all months in 2020, peak summer and winter months of 2025 and 2030), at each gas storage facility.

## Hydraulic Modeling: The Feasibility Assessment

### Feasibility Assessment: Introduction

Once the Reliability Assessment is complete, one must investigate whether the minimum storage schedule is feasible to achieve. Therefore, the next step in the analysis is a Feasibility Assessment. In the Feasibility Assessment, the gas system is simulated under typical demand conditions to determine the available capacity for injection at the SoCalGas storage facilities. The distribution among the different storage fields requires more hydraulic analysis since it depends on the location of those storage fields and the gas system properties.

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<sup>13</sup> The storage volume at PDR is small enough that, with appropriate forecasting and gas operations, PDR will be at maximum capacity when needed for a highly stressed day.

<sup>14</sup> These maximum withdrawal rate curves should be updated periodically. Any significant change in these curves should trigger a review of the Reliability Assessment.

### Feasibility Assessment: The Feasibility Standard

A Feasibility Assessment will be carried out to determine if the monthly minimum storage volume targets determined by the Reliability Assessment can be maintained throughout the year. The Reliability Assessment was carried out under highly stressed conditions to determine if the system could maintain adequate gas delivery performance during these infrequent scenarios. In contrast, the Feasibility Assessment is carried out under “typical” or “nominal” system conditions for each month to assess the nominal available gas storage injection capacity and any associated withdrawals that may be required in nominal monthly operation. These monthly nominal injection or withdrawal capacities are then used to determine if the monthly storage volumes are feasible to achieve.

A key assumption of the analysis framed here is that 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.

### Feasibility Assessment: Simulations Inputs

The gas system is simulated under typical demand conditions to determine the available capacity for injections at the SoCalGas storage facilities and if the Minimum Gas Storage Schedule from the Reliability Assessment can be met. As with the Reliability Assessment, the hydraulic simulations for the Feasibility Assessment require several inputs, namely gas demand profiles, gas curtailments, assumptions about storage facilities, assumptions about capacity utilization, and assumptions about the gas network outages. A description of each input follows.

#### 1. Hourly gas load profiles

For the natural gas system, hourly load profiles are defined for the nominal operating conditions, i.e., the nominal operating day for each month of the simulated year(s). The total load profile is determined from its three constituents:

- *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 from smart meter data.
- *Noncore, electric gas load*  
The daily gas consumption profiles from a year-long electric production cost model are produced from hourly output data from each month of the

year to define the expected or average daily noncore, electric gas load. The electric PCM will be performed without constraints (“unconstrained gas scenario”) on gas availability so that the electric generation is committed and dispatched to achieve economically optimal operations while maintaining NERC reliability standards.

- *Noncore, non-electric gas load*  
Expected or average daily core gas load profile for each month of the analysis year directly from SoCalGas.

## 2. Gas curtailments

Since the Feasibility Assessment simulates the gas system throughout a typical year, no curtailments are assumed.

## 3. Gas storage facilities

The natural gas pipeline and storage system is modeled for the nominal day in each month. Any available excess gas system capacity is used to support injections into underground storage. Gas storage withdrawals are used to eliminate deficits in gas system flow relative to load or to provide system balancing. The injection and withdrawals capacities are used to calculate whether the required storage inventories can be achieved over a full month. If the available injection capacity (minus required withdrawals) is sufficient to meet the required gas storage monthly minimums determined in the Reliability Assessment, the Minimum Gas Storage Schedule is deemed feasible. Each of these facilities is unique and operated in a specific manner for the greatest benefit to the gas system<sup>1</sup> as described below.

- *Playa Del Rey (PDR)*  
The PDR storage field has relatively small storage capacity, but it may still be key to gas balancing within the Los Angeles Basin for nominal operations during certain months of the analysis year. PDR’s small storage capacity means that it cannot be continually drawn down. In the nominal monthly day of the Feasibility Assessment, PDR must start and end the day with the same quantity of stored gas, 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.

- *Non-PDR Gas Storage*

La Goleta, Honor Rancho and Aliso Canyon can all support consistent net withdrawals or net injections over the monthly period in the Feasibility Assessment. In the Feasibility Assessment, for each month of the analysis year:

- If there is excess gas system capacity to support net injections, the net injections in the hydraulic model are distributed across the non-PDR facilities to: 1) ensure all facilities are at least above their required monthly minimums from the Reliability Assessment and 2) to maximize the total gas stored in aggregate fleet of storage facilities.
- If gas storage net withdrawals are needed, the net withdrawals in the hydraulic model are distributed across the non-PDR facilities to: 1) ensure that all gas loads are met without imposing curtailments and 2) to ensure that all facilities are at least above their required monthly minimums from the Reliability Assessment.

#### 4. **Flowing Gas Supplies**

As in the Reliability Assessment, the total transmission zone capacity will be assumed at 85% for the Northern and Southern Zone and 100% for the Wheeler Ridge Zone. These values may change depending on the analysis of outage history.

#### 5. **Outages**

In contrast to the Reliability Assessment, the Feasibility Assessment must consider both planned and unplanned pipeline and storage outages. Both types of outages occur under nominal operating conditions and impact the average ability to inject natural gas into storage or reduce the average flowing supply, which may increase the demand for storage withdrawals. For the Feasibility Assessment, we propose that each gas pipeline system model (one model per month of the year) be subject to reductions in flowing supply and reductions in storage operations that are consistent with expectations from the historical record of these outages during that month.

Such an analysis is presented in Table 3 of the 2016 version of the Aliso Canyon Risk Assessment Technical Report, which will be updated for this hydraulic

analysis.<sup>15</sup> If insufficient data exist to determine the expected planned and unplanned outages monthly, the expected outages may be determined on a yearly basis and the same outages applied in each of the 12 monthly gas system models.

In contrast to the Reliability Assessment, there is no apparent need to consider the highest impact pipeline or storage outage since the Feasibility Assessment assumes a typical year with typical demand and, consequently, a typical outage situation. However, it is important to consider the “typical” outages before and after the October 2015 leak. CPUC staff will analyze the impact of outages on capacity utilization before and after October 2015. CPUC staff will then choose a representative period of “typical” outages for the year 2020 and possibly the years 2025 and 2030.

#### Feasibility Assessment: Simulation Outputs

The gas storage net injections and net withdrawals from the hydraulic modeling are for a nominal day for each month of the analysis year. These injections/withdrawals are integrated over each day of the month to compute the gas storage volume at the start of the next month. If the simulated storage volumes at each facility are above the Minimum Gas Storage Schedule determined from the Reliability Assessment, the gas system is deemed feasible.

#### Hydraulic Modeling: Drawing Conclusions from Both Assessments

The graded approach to the hydraulic modeling will result in 32 scenarios for the Reliability Assessment and at least 12 scenarios for the Feasibility Assessment as determined by various inputs and assumptions. Thirty-six of these scenarios result from performing the Reliability and Feasibility Assessments for the near term (12 months, for typical, peak and extreme peak conditions for year 2020). Another eight scenarios result from performing the Reliability Assessment for two seasons for the out years (2025 & 2030) for peak and extreme peak conditions. The table below summarizes these scenarios.

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<sup>15</sup> Aliso Canyon Risk Assessment Technical Report, April 2016 version, pg. 36:  
[http://www.energy.ca.gov/2016\\_energypolicy/documents/2016-04-08\\_joint\\_agency\\_workshop/Aliso\\_Canyon\\_Risk\\_Assessment\\_Technical\\_Report.pdf](http://www.energy.ca.gov/2016_energypolicy/documents/2016-04-08_joint_agency_workshop/Aliso_Canyon_Risk_Assessment_Technical_Report.pdf)

Table 1: Hydraulic Modeling Scenarios

Scenario #	Year Studied	Operating Condition	Outages	Curtailments
Reliability		Peak (1-in-10) Extreme Peak (1-in-35)	U: Unplanned P: Planned	
1-12	Monthly 2020	Peak	U	None
13-24	Monthly 2020	Extreme Peak	U	Some
25	Summer 2025	Peak	U	None
26	Summer 2025	Extreme Peak	U	Some
27	Winter 2025	Peak	U	None
28	Winter 2025	Extreme Peak	U	Some
29	Summer 2030	Peak	U	None
30	Summer 2030	Extreme Peak	U	Some
31	Winter 2030	Peak	U	None
32	Winter 2030	Extreme Peak	U	Some
Feasibility				
33-44	Monthly, 2020	Typical	U+P	None

If for any of the studied months, the Reliability Assessment shows that a minimum storage inventory is required at Aliso Canyon, then Aliso Canyon must remain open in the corresponding year. The analysis of the two peak months in the out years provides an answer to the key question of this analysis, i.e., whether Aliso Canyon can be shut down in those years.

### Hydraulic Modeling: Potential Future Analysis

The Reliability Assessment determines the minimum monthly inventory targets for underground storage at each facility to support the required SoCalGas system performance under the stressed conditions of the reliability standard. On the other hand, the Feasibility Assessment determines whether the monthly minimum storage volume targets determined by the Reliability Assessment can be maintained throughout a typical year.

The Reliability Assessment may return a result that does not meet the required natural gas delivery performance, even when implementing the full set of allowable operational actions. In this case, the Reliability Assessment will provide insight into any unmet criteria or bottlenecks preventing the gas system from operating reliably with or without Aliso Canyon storage field.

In a future analysis, a sensitivity analysis may be performed to estimate what additional actions or alternative operational actions may be taken beyond the set of operational



actions defined by the reliability standard to reduce the minimum storage requirement at Aliso Canyon to zero.

## Production Cost Modeling: Introduction

The availability of natural gas storage, particularly in the western Los Angeles Basin, has several important interactions with the overall gas pipeline system in regulating pressure, storing or releasing natural gas, and providing gas supply at locations distant from receipt points. Aliso Canyon also produces effects on the electricity system by providing readily available supply near the power plants that will burn the natural gas.

By performing Production Cost Modeling (PCM), CPUC staff seeks to quantify what effects will be produced by the closure or curtailment of Aliso Canyon Gas Storage Field, particularly on the electric system. PCM analysis will provide another perspective alongside the hydraulic modeling to evaluate the closure or curtailment of Aliso Canyon.

CPUC staff will perform PCM modeling to determine two main data sets that input into other models and one dataset that will illustrate results of PCM analysis. First, staff will produce hourly gas demand from electric generators representing two scenarios. The first one is the “Unconstrained Gas” scenario, which represents conditions where electric generators are able to start up, generate, and ramp according to the technical parameters of the individual power plants, without constraints caused by pipeline or gas supply curtailment. The second scenario, the “Minimum Local Generation” scenario, represents conditions where pipeline and gas storage constraints have forced curtailment of electric generation. In this scenario, electric generators would be curtailed excepting only the minimum amount of generation deemed necessary by the Power Flow Analysis discussed below.

Hourly gas use derived from electric generator dispatch will be aggregated by month, with hourly shapes selected to represent the 1-in-10 Peak Design day and the 1-in-35 Extreme Peak design day. This data will be used for the Hydraulic Model.

To answer the questions raised in the OII, PCM analysis will specifically produce results quantifying the reliability effects (in terms of “Loss of Loss Expectation” or LOLE) and cost effects in terms of increase in total production cost resulting from removal of gas supply at Aliso.

## Production Cost Modeling Proposal

CPUC staff proposes to perform Production Cost Modeling (PCM) analysis in coordination with the hydraulic modeling reliability assessment. This PCM analysis will provide necessary inputs to the Reliability Assessment in the hydraulic modeling as well as test the effects on electric system reliability and production costs that are the result of gas limitations found by the Reliability Assessment. If needed, studies can be performed iteratively to fully determine how to minimize reliance on Aliso Canyon gas storage availability and to achieve the objectives of the study.

CPUC staff has developed a standard process for completing PCM analysis to support the Resource Adequacy (RA) and Integrated Resource planning (IRP) proceedings. The approach and development of the associated dataset is described in the “Unified Inputs and Assumptions for RA and IRP PCM Modeling” (Unified I/A) and is available on the CPUC website.<sup>16</sup> In general, the Unified I/A document contains a description of the specific modeling software currently used by CPUC staff (Strategic Energy Risk Valuation Model or SERVM) and the key datasets and data sources for use in the SERVM model. The Unified I/A also describes the modeling process of performing stochastic reliability studies in a determined order based on LOLE and Effective Load Carrying Capability (ELCC) metrics.<sup>17</sup>

In addition to general guidelines related to PCM modeling, CPUC staff proposes some assumptions unique to the PCM modeling in this OII. In addition to the economic buffering effects of nearby gas storage on core and noncore gas prices, Aliso Canyon also provides either extra stored gas when demand is higher than the flowing supply or the ability to react to gas pressures swings at various nearby delivery points with greater speed and flexibility than would otherwise be the case. Both these effects are important to the electric system, and to capture the effects of the removal or minimized usage of the Aliso Canyon storage field, assumptions need to be made about how to reflect the absence of nearby stored gas on the operations of power plants within a PCM framework.

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<sup>16</sup> Document is linked to the CPUC website here:

<http://www.cpuc.ca.gov/General.aspx?id=6442451972>

<sup>17</sup> The Unified I/A will be updated with SB100, signed into law on September 10, 2018

The Aliso storage field primarily interacts with electricity generating plants in the Western Los Angeles Basin, both in the CAISO balancing authority and the LADWP balancing authority area. Curtailment or closure of the Aliso storage field will affect the plants' ramping ability, ability to start up on short notice, and other operating parameters, which in turn may affect electric system costs and reliability. In addition, under the 1-in-35 (extreme peak) design standard adopted in SoCalGas Tariff Rule 23, complete curtailment of a larger group of electric generators may be required to protect core customer gas supply.<sup>18</sup>

Finally, several data inputs and outputs from the PCM analysis will feed into the hydraulic modeling analysis. In particular, the expected hourly dispatch of electric generators at various points of the SoCalGas gas transmission system over the hours of a day will affect the ability to serve core gas demand elsewhere, impacting the flow and pressure on network elements that the hydraulic model will need to simulate.

### Proposed Sequence of Studies

Given these PCM effects, Energy Division proposes to evaluate the impacts of Aliso storage field closure or curtailment via a series of modeling processes. Figure 2 illustrates the sequence of studies planned. CPUC staff proposes to follow a bottom-up process.

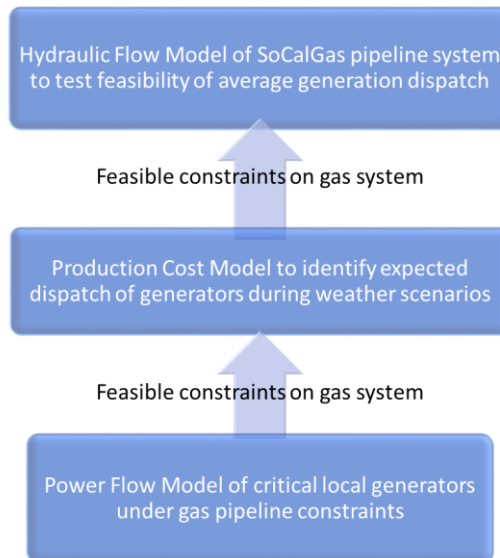


Figure 2: Bottom Up Sequence

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<sup>18</sup> SoCalGas Tariff Rule 23 is linked here: <https://www.socalgas.com/regulatory/tariffs/tariffs-rules.shtml>

First, CPUC staff will incorporate the Power Flow modeling performed by LADWP and CAISO as a basis for determining the minimum local generation that must be online in order to meet NERC requirements. The Power Flow modeling is a foundation in the bottom-up approach, which is followed by the PCM analysis. Finally, inputs are generated from those models and input into the Hydraulic Model. The Power Flow model results from the CAISO and LADWP will determine generation needed for minimum transmission reliability in the LA Basin (Minimum Local Generation) under a scenario of no gas constraints (unconstrained system), then those values feed into a PCM analysis to determine the likely dispatch patterns of the overall electricity system, keeping the Minimum Local Generation in operation (also under the assumption of unconstrained system).

Hourly profiles of electricity generation will be collected and assembled into input data for the Hydraulic Modeling, which will test the feasibility and reliability of those unconstrained system hourly profiles.

### PCM Analysis Plan

PCM modeling will be conducted with the SERVIM model, developed by Astrapé Consulting. SERVIM simulates least-cost dispatch for a user-defined set of generating resources and loads. It calculates numerous reliability and cost metrics for a given study year, considering expected weather, overall economic growth, and performance of the generating resources. More detail regarding source and calculation of the modeling inputs, as well as their use in the SERVIM model, are specified in the Unified I/A.

Energy Division will use the SERVIM model and the assumptions developed in the Unified I/A to simulate electric generation dispatch for the Unconstrained Gas scenario. Hourly shapes for the Hydraulic Modeling will be created for this scenario.

For the Extreme Peak Minimum Local generation scenario, the Hydraulic Modeling will determine a feasible level of gas demand for electricity generation on an hourly or total daily basis to be infeasible, staff will modify the standard operating inputs in SERVIM to implement a third “Constrained Gas” case representative of the outcome of Hydraulic Modeling.

PCM Modeling will be performed according to the process laid out below.

- CPUC staff will perform the PCM study under the “Unconstrained Gas” scenario to determine reliability and cost of the existing system without any changes made in the three study years of 2020, 2025, and 2030. This study is similar to the work performed for the IRP proceeding as described in the Unified I/A document.

- CPUC staff will develop forecasted hourly generation profiles based on the hourly results of the “Unconstrained Gas” scenario in the PCM study for the set of generating plants in the SoCalGas system, grouping generators by delivery point to provide input to the hydraulic model of the Reliability Assessment.
- CPUC staff will oversee and evaluate the Hydraulic Modeling. The results of that modeling will inform constraints to place on power plants related to Aliso Canyon curtailment.
- CPUC staff will receive and implement any curtailment information from the Reliability Assessment for the 1-in-35 (extreme peak) design day and identify any changes to operating parameters for individual power plants or groups of power plants then evaluate those changes in a PCM model.
- CPUC staff will report results to stakeholders and determine if the effects of Aliso curtailment or removal are significant enough to warrant evaluation of any planned action regarding the Aliso gas storage field.

### Creation of Daily Gas Usage Profiles

Staff will create daily operating profiles for power plants in Southern California that represent the 1-in-10 Peak and 1-in-35 Extreme Peak operating conditions. Staff will then run SERVM to model hourly electric generation gas demand without gas constraints, export hourly dispatch and fuel use data, and select from the large dataset of possible dispatch profiles. Staff will select two 24-hour profiles for each month to represent the 1-in-10 (peak) and 1-in-35 (extreme peak) gas use design days will be run. These hourly profiles will be used in the hydraulic model Feasibility Assessment and Reliability Assessment. Staff will follow the process laid out below to generate hourly gas use profiles for each study year:

1. Simulate hourly dispatch over all hours (8,760 hours total) of the study year, preserving Minimum Local Generation.
2. Export hourly electricity generation profiles by individual power plant. Collect daily gas use for all plants in Southern California Edison (SCE), LADWP, and San Diego Gas & Electric (SDG&E) areas and assemble daily electric generation shapes totaled across the three areas ranking them in order of descending total gas use and grouping them by month.
3. From a dataset that includes 365 days for 175 cases (63,875 days total), select one day per month (out of approximately 5,250 daily shapes per month) that represents the 1-in-10 (90<sup>th</sup> percentile) level, and another day that represents the 1-in-35 (97.1<sup>th</sup> percentile) dispatch profile based on total gas use in that month.

No scaling up to peak is required, as these shapes represent the study year in question already.

4. For purposes of the Feasibility Assessment CPUC staff will develop representative hourly electric generation that represents the 50% percentile dispatch patterns, based on total gas use for that month. In total three sets of hourly generation profiles will be developed per month and per future study year (total 36 hourly generation shapes).
5. If shapes are strongly similar for a whole season or across many months, profile shapes may be merged or dropped, but no less than four profile shapes will be created to represent a peak and an extreme peak condition for the summer and winter seasons.
6. Daily gas use shapes for the selected day for each electricity generator will be aggregated by gas delivery point (usually each power plant has its own gas delivery point) and combined with the corresponding monthly shapes aggregated to zip code selected to represent core gas for the corresponding month and study year and loaded into the hydraulic model.

### Proposed Changes to Plant Operating Parameters to Implement Gas Constraints

CPUC Staff has gathered the necessary operating data to implement a PCM model in the SERVM model representing a condition without curtailment or shortage of fuel availability. To implement curtailment of Aliso Canyon in SERVM, staff would need to implement the effects in terms of how power plants will dispatch.

In the event of Aliso closure, power plants in Southern California will need to be scheduled well in advance, to allow for delivery from a distant gas delivery hub and to prevent imbalances that were previously mitigated with storage. CPUC staff proposes to simulate this effect in SERVM by restricting the ramp rate and increasing the startup up time and extending the startup profile of plants in the Western LA Basin.

CPUC staff will also seek to simulate the effect of a Rule 23 curtailment on a 1-in-35 (extreme peak) design day by limiting total gas volume to all the power plants in the SoCalGas system and simulating the effect of a total volumetric constraint over a group of power plants. The total volumetric constraint will be set at the level resulting from the hydraulic model Reliability Assessment 1-in-35 (extreme peak) design day modeling.

### Production Cost Modeling: Drawing Conclusions

PCM modeling will be completed to answer the fundamental question, “Does the closure or curtailment of the Aliso Canyon Gas Storage Field cause any significant

reliability effects (change LOLE by 5%) or affect production costs (change total production cost by 5%)?” This can be determined by modeling the Unconstrained Gas scenario for the 1-in-10 peak design day, tabulating the reliability and cost results for the CAISO aggregate system and the LADWP system, then running the Constrained Gas scenario after the Hydraulic Model is run, and comparing the LOLE and total production costs results between the two scenarios.

## Economic Modeling

### Outline of Three Proposed Economic Models

The purpose of the economic modeling conducted here is to estimate the impacts of reduction in Aliso gas storage on core and noncore natural gas ratepayers. CPUC staff proposes to perform an economic study consisting of three statistical and/or econometric models. These models will use historical and future gas price and gas billing data to analyze, estimate, and predict the relationships of the gas system to rate impacts for core gas customers. Staff will also study possible effects on electricity prices resulting from gas curtailment. This includes analyzing the causes and impacts of natural gas price volatility, the impact of reduction in natural gas storage capability on core customer ratepayer bills, and the impact of tighter gas supply in the SoCalGas system on energy costs for power generation in the CAISO territory.

The Economic Modeling section in the earlier Draft Framework and Scenarios Report proposed four models. Since then, comments from stakeholders and more analysis have brought CPUC staff to now proposes eliminate the analysis of factors that motivate natural gas storage decisions in the SoCalGas system, while still retaining the three remaining analyses.

The three proposed analyses are listed here and described briefly below.

- Part 1 (Volatility Analysis) will estimate and predict the impacts of natural gas price volatility on core natural gas customers.
- Part 2 (The Impact of Natural Gas Storage on Ratepayers’ Bills) will quantify and compare the impacts of gas storage availability on ratepayer costs for core customers in similarly situated geographic areas.
- Part 3 (The Impact of Tighter Gas Supply in SoCalGas System on Power Generation in the CAISO Territory) will assess the effect of storage availability on CAISO wholesale power generation by analyzing the impacts of gas

availability on power plant efficiency and the congestion cost related to generation.

### Part 1: Volatility Analysis

In addition to improving reliability, storage can be used to reduce the economic impact of fluctuations in natural gas prices. Gas can be purchased and stored in the off-season, when prices are generally lower, for use in the summer and winter, when demand and prices tend to be higher. Storage also helps moderate costs during temporary price spikes, which typically occur during extreme weather events. Finally, natural gas storage provides a means to mitigate imbalances and penalties related to imbalances during operational flow orders (OFOs), as any imbalances in gas deliveries can either be supplemented with gas withdrawn from storage (if deliveries are too low) or injected into storage (if deliveries are too high).

Loss of storage impacts core and noncore customers differently. SoCalGas purchases both gas and storage rights for core customers while noncore customers buy their own gas and have historically had the option to pay for storage rights.<sup>19</sup> Since gas is a pass-through cost for core customers, meaning the price paid by the utility is passed on to residential and small business consumers, loss of storage could increase core 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 were put in place. If Aliso is permanently closed, their ability to purchase storage would likely be severely reduced compared to historic norms, leaving them more exposed to market volatility and penalties related to changes in their dispatch or gas use that they discover after their daily gas is scheduled.

Since SoCalGas core and noncore customers are price takers, it is assumed that the value of SoCalGas storage will be reflected in the SoCalGas Citygate price. Therefore, CPUC staff will perform a volatility analysis on prices of gas purchased at the SoCalGas Citygate hub and compare that result to the volatility of gas prices in other relevant markets. CPUC staff will evaluate volatilities of natural gas prices at hubs including SoCalGas Citygate, SoCalGas border, PG&E Citygate, Henry Hub, El Paso San Juan Basin, and El Paso Permian Basin by using data from Natural Gas Intelligence (NGI).

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<sup>19</sup> For more information: <https://www.platts.com/commodity/natural-gas>



Volatility is typically quantified as the standard deviation of price returns.<sup>20</sup> The return on price is commonly determined in continuous time and expressed using a natural logarithm function of the natural gas price. Once the volatility is computed, if more variation is observed in the SoCalGas Citygate price compared to other markets, CPUC staff will perform a time series model with explanatory variables to study the relationship between the daily price return of the SoCalGas Citygate natural gas pricing hub and explanatory variables.

The standard definition of the price return in one period  $r(t, t-1)$  is calculated as:

$$r(t, t-1) = \ln(p(t)/p(t-1))$$

Where  $p(t)$  is the price of natural gas at time  $t$  and  $\ln$  is the natural logarithm function. If more variation is observed in the SoCalGas Citygate compared to other markets after computing the volatility using the standard deviation of the price returns.

The potential list of variables will include the daily natural gas storage inventories in SoCalGas storage facilities, the reduced capacity of the pipeline system due to pipeline outages, beginning-of-the-day inventory level, day-of-week variables, heating degree days (HDD), cooling degree days (CDD), and variables indicating season and month, the incidence of an operational flow order, the dispatched quantity in the Day Ahead Electricity Market minus the dispatched quantity in the Real Time Electricity Market, and other variables as listed below.

In addition, CPUC staff will evaluate whether the Generalized AutoRegressive Conditional Heteroscedasticity (GARCH) model will be appropriate to this analysis, assuming the data satisfy the model assumptions.<sup>21</sup> These models are especially useful when the goal of the study is to analyze and forecast volatility. These models are commonly used in modeling financial time series that exhibit time-varying volatility.

The initial Time series model will take the structure below:

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<sup>20</sup> For the definition of volatility, see: <https://ssrn.com/abstract=2194214>

<sup>21</sup> For more information on GARCH: <https://pubs.aeaweb.org/doi/pdfplus/10.1257/jep.15.4.157>

$$R_t = C + \sum_{i=1}^p \varphi_i R_{t-i} + \sum_{k=1}^r \beta_k X_t + \varepsilon_t$$

- $C$  is the constant term (the intercept).
- $R_t$  is the price returns at time  $t$  (dependent variable).
- $\sum_{i=1}^p \varphi_i R_{t-i}$ :  $R_{t-i}$  is the lag of price return (the price return from the previous period or periods) and  $\varphi$  is the coefficient or coefficients to be estimated.
- $\sum_{k=1}^r \beta_k X_t$ :  $\beta$  is the coefficient or coefficients of interest to be estimated.  $X_t$  is a set of the potential explanatory variables to be tested and included in the model.

This set includes:

- Beginning-of-the-day stock level.
- Day-of-week dummies.
- Heating degree days (HDD) and cooling degree days (CDD)
- Season and month dummy variables
- Dummy variable set to 1 in the event of an Operational Flow Order. This variable will consist of two dummy variables, one for incidence of low OFOs and the other for incidence of high OFOs.
- Basis differential.
- The customer imbalance in the SoCalGas system.
- Dummy variable set to 1 if there is a Curtailment Watch.
- An interaction variable  $X_4$  which represents the effect of the dependent variable at different levels of BTS available pipeline capacity. This variable is meant to represent the interaction of storage inventory and BTS available pipeline capacity. This variable is constructed as follows:
  - A variable ( $X_1$ ) which represents total daily storage inventory across SoCalGas territory.
  - A variable ( $X_2$ ) which represents firm pipeline capacity usage level. This variable would equal the ratio of daily total scheduled gas to daily total daily available operating capacity. This variable is a proxy for the pipeline outages.
  - A dummy variable ( $X_3$ ) to indicate whether variable  $X_2$  is equal to or greater than 80% or less than 80%.
- The dispatched quantity in Electricity Day Ahead Market- The dispatched quantity in Electricity Real Time Market.
- $\varepsilon_t$  is the stochastic disturbance.

The table below shows the variables and data source: 2015-2018

Table 2: Part 1 Data Sources

<b>Variable</b>	<b>Data Source</b>
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, Henry Hub, El Paso San Juan Basin and El Paso Permian Basin	NGI
Daily available operating capacity and Scheduled Gas in SoCalGas system	DR and Envoy
The customer imbalance in the SoCalGas system	Envoy
Curtailement Watch	DR
The dispatched quantity in the Electricity Day Ahead Market: The dispatched quantity in the Electricity Real Time Market	CAISO settlement data

## Part 2: The Impact of Natural Gas Storage on Ratepayers' Bills

To quantify the effect of storage availability on ratepayers, Energy Division proposes an econometrics technique called "Difference in Differences" (DID)<sup>22</sup>. In the DID model, outcomes are observed for two groups during two time periods. One of the groups (treatment group) is exposed to treatment in the second period but not in the first period. The other group (control group) is not exposed during either period. The DID approach can be applied to repeated cross sections of a group or panel data over a certain time period. The key assumption in DID is the parallel trend assumption, which states that the average change in the treatment group represents the counterfactual change in the treatment group if there were no treatment.

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<sup>22</sup> For more information on Difference in Differences: [http://www.nber.org/WNE/Slides7-31-07/slides\\_10\\_diffindiffs.pdf](http://www.nber.org/WNE/Slides7-31-07/slides_10_diffindiffs.pdf)

CPUC staff will use monthly bill data for SoCalGas (treatment group) and PG&E (control group) customers by household with similar zip codes representing similar areas (similar in weather, household size, income, etc.) before and after the Aliso Canyon leak required curtailment of the Aliso Canyon storage facility. CPUC staff will study customer prices for customers in SoCalGas and PG&E service areas in the same zip code including communities in Arvin, Bakersfield, Fellows, Fresno, Del Ray, Fowler, Paso Robles, Selma, Taft, Tehachapi, and Templeton.

Outcomes before and after the Aliso Canyon leak will be compared between the study group and the comparison group without the exposure (group A, i.e. PG&E customers) and the study group with the exposure (group B, i.e. SoCalGas customers). This will allow CPUC staff to estimate the effect of curtailment of the Aliso Canyon natural gas storage facility on the monthly natural gas bills of ratepayers in areas close to each other but differing by their exposure to curtailment of natural gas storage.

If the difference in ratepayer cost before and after the Aliso Canyon leak for SoCalGas customers is equal to the difference in ratepayer cost before and after the Aliso Canyon leak for PG&E customers, then the DID estimate is zero and not statistically significant, which means that there is no relationship between low levels of Aliso Canyon storage and the investigated outcome. On the contrary, if there is a relationship between the storage and investigated outcomes, then the DID estimate will be statistically significant. Also, the model will include control variables such as the pipeline outages to distinguish between the effect of storage and the pipeline outages.

Two differences in outcomes are important: 1) the difference in average per unit gas prices in customer monthly bills before vs. after the Aliso Canyon leak for the SoCalGas customers is  $(B2 - B1)$  and 2) the difference in ratepayer cost after vs. before the Aliso Canyon leak for the PG&E customers is  $(A2 - A1)$ . The change in outcomes that are related to the Aliso Canyon incident can then be estimated from the DID analysis as follows:  $(B2 - B1) - (A2 - A1)$ . If there is no relationship between the storage and subsequent outcomes, then the DID estimate is equal to zero and not statistically significant. If there is a relationship between the storage and subsequent outcomes, then the DID estimate will be statistically significant.

These estimates will be derived from a regression model:

$$Y_{st} = \beta_0 + \beta_1 T_s + \beta_2 PT_t + \beta_3 (T_s \times PT_t) + \sum_{k=4}^r \beta_k X + \varepsilon_{st}$$

- $Y_{st}$  the observed outcome in group  $s$  and period  $t$ . In this case, it is the individual ratepayer's monthly bill cost.
- $T_s$  is a dummy variable set to 1 if the observation is from the "treatment" group in either time period.
- $PT_t$  is a dummy variable set to 1 if the observation is from the post treatment period in either group.
- $\varepsilon_{st}$  is an error term,  $\beta_0$  is the intercept,  $\beta_1$  is the coefficient of the  $T_s$  and  $\beta_2$  is the coefficient of  $PT_t$ .
- $\beta_3$  is coefficient of the treatment effect, which is the coefficient of interest. The estimate of  $\beta_3$  is identical to the double difference:  $(B_2 - B_1) - (A_2 - A_1)$ .
- $\sum_{k=4}^r \beta_k X$ :  $\beta_k$ s are the coefficients to be estimated.  $X$  is a set of the potential explanatory variables to be tested and included in the model. This set of explanatory variables could include variables for low-income households, storage inventory levels, and pipeline capacity, but data need to be evaluated first.
  - Beginning-of-the-day stock level.
  - Low income households' variable.
  - Heating degree days (HDD) and cooling degree days (CDD) or seasons or months.
  - Operational flow order. OFOs variable will consist of two sets: low and high OFOs.
  - A variable ( $X_1$ ) which represents firm pipeline capacity usage level. This variable would equal the ratio of daily total scheduled gas to daily available operating capacity.
  - A dummy ( $X_2$ ) to indicate whether variable  $X_1$  is equal to or greater than 80% or less than 80%.
  - Basis differential: SoCal Border daily spot price – Henry Hub spot price.

The graph below illustrates the basic setting of the DID. The hypothesis is that the control group and the treatment group would follow the same cost trajectory with respect to time before and after the curtailment of the Aliso Canyon storage field due to leak.

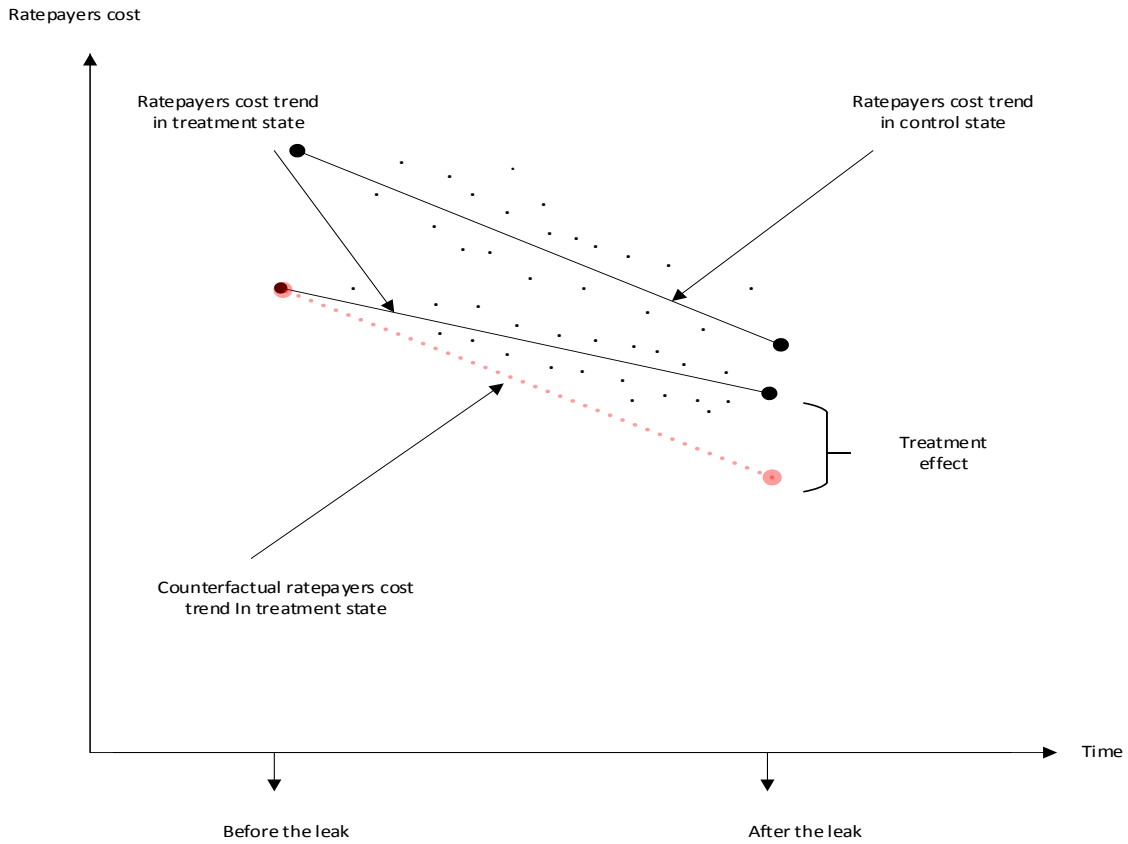


Figure 3: Causal effects in the differences-in-differences model

In addition to the DID analysis above, CPUC staff will perform statistical analysis of the underlying billing data to compare bill impacts individually for SoCalGas CARE households and non-CARE households during the summer and winter before and after the Aliso Canyon incident. This statistical analysis will be performed on historical bill data and will include the mean and standard deviation of baseline price, average price, marginal price, gas consumption, and total bill.

Also, CPUC staff will analyze monthly data from SoCalGas rate schedules. CPUC staff will look at historical trends in the gas charges and non gas charges by customer class as a share of total retail gas rate. The shares will be calculated with the equations below: Historical share = Gas charge/Total charge and Historical share = NonGas charge/Total charge.

The table below shows the data source:

*Table 3: Part 2 Data Sources*

<b>Variable</b>	<b>Data Source</b>
Bill data	DR from SoCalGas and PG&E
Storage inventory level	DR from SoCalGas
Low income households	DR from SoCalGas and PG&E
Pipeline available capacity	DR from SoCalGas
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 SoCalGas border, Henry Hub	NGI
Daily pipeline outages in SoCalGas system	DR and Envoy
Daily Operating Capacity	Envoy

### Part 3: The Impact of Tighter Gas Supply in SoCalGas System on Power Generation in the CAISO Territory

The Aliso Canyon facility provides gas supplies to natural gas-fired power plants that play a central role in meeting regional electrical demand and helps them meet peak electrical demands during the summer months. Constrained gas supply from Aliso Canyon could lead to a decrease in the availability of natural gas in Southern California, which would lead to dispatch of power plants outside of Southern California. The increased dispatch and flow of electricity into Southern California may raise electricity prices either through dispatching less fuel-efficient plants or by creating congestion on the electricity transmission system that creates congestion costs. Arguably, these dynamics could mean higher energy costs in the CAISO markets because of the congestion on the transmission network.

Congestion occurs when available, least-cost energy cannot be delivered to some loads because transmission facilities do not have sufficient capacity to deliver the energy. When the least-cost, available energy cannot be delivered to load in a transmission-constrained area, higher cost electricity generation in the constrained area must be dispatched to meet that load. The result is the price of energy in the constrained area

will be higher than in the unconstrained area because of the combination of transmission limitations and the costs of local generation.

CPUC staff proposes two criteria to assess the impact of tighter gas supply on the power generation in the CAISO's territory: the implied market heat rate and the congestion rent assessment, which are discussed briefly below.

### Implied Market Heat Rate

Heat rate refers to the power plant efficiency in converting fuel to electricity. Heat rate is expressed as the number of million British thermal units (MMBtu) required to produce a megawatt hour (MWh) of electricity. Lower heat rates are associated with more efficient power generating plants. Implied market heat rate can be obtained by dividing electric price by the natural gas price.<sup>23</sup> Implied market heat rate is the break-even natural gas market heat rate assumed because only a natural gas generator with an operating heat rate below the implied heat rate value can make money by burning natural gas to generate electricity. Natural gas plants with a higher operating heat rate cannot make money at the prevailing electricity and natural gas prices. CPUC staff will calculate the implied market heat rate for Northern and Southern California parts of CAISO using North of Path 15 (NP15) and South of Path 15 (SP15) day-ahead market electricity prices (MWh), generation data based on the transmission access charge area, the PG&E Citygate gas price, and the SoCalGas Citygate gas price. In addition, CPUC staff will conduct implied market heat rate analysis for the highest priced hours and the lowest price hours per year available for both Northern and Southern California.

The implied market heat rate is calculated as shown below. The day-ahead electric price and generation data will be collected from the CAISO's Open Access Same-time Information System (OASIS) site. Staff will use data from 2015 to early 2018.

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<sup>23</sup> Definition of Implied Heat rate according to the U.S. Energy Information Administration, <https://www.eia.gov/tools/glossary/index.php?id=I>:

A calculation of the day-ahead electric price divided by the day-ahead natural gas price. Implied heat rate is also known as the 'break-even natural gas market heat rate,' because only a natural gas generator with an operating heat rate (measure of unit efficiency) below the implied heat rate value can make money by burning natural gas to generate power. Natural gas plants with a higher operating heat rate cannot make money at the prevailing electricity and natural gas prices.



*For Northern California:*

$$\text{Implied Market Heat Ratet} = \frac{DALMPt}{DNGPt}$$

*Implied Market Heat Ratet* is the daily implied market heat rate in Northern California. *DNGPt* is the daily gas price for PG&E Citygate.

*DALMPt* is the daily day-ahead weighted average price =  $\frac{\sum_h^H LMP_h * GEN_h}{\sum_h^H GEN_h}$

*LMP<sub>h</sub>* is the hourly locational marginal price for NP15.

*GEN<sub>h</sub>* is the hourly generation for the Northern transmission access charge (TAC) area. It is represented as TAC\_NORTH in OASIS.

$\sum_h^H GEN_h$  is the total generation for all 24 hours in each day for the TAC\_NORTH area.

*For Southern California:*

$$\text{Implied Market Heat Ratet} = \frac{DALMPt}{DNGPt}$$

*Implied Heat Ratet* is the daily implied heat rate in Southern California.

*DNGPt* is the daily gas price for SoCalGas Citygate.

*DALMPt* is the daily day-ahead weighted average price =  $\frac{\sum_h^H LMP_h * GEN_h}{\sum_h^H GEN_h}$

*LMP<sub>h</sub>* is the hourly locational marginal price for SP15.

*GEN<sub>h</sub>* is the hourly generation for the Southern transmission access charge (TAC) area. It is represented as TAC\_ECNTNTR and TAC\_SOUTH in OASIS.

$\sum_h^H GEN_h$  is the total generation for all 24 hours in each day for the TAC\_ECNTNTR and TAC\_SOUTH area combined.

In addition, CPUC staff will provide implied market heat rate analysis by load level for both Northern and Southern California.

### Congestion Rent Assessment

CPUC staff will assess the congestion cost related to generation. CPUC staff will calculate monthly congestion rent revenue from generation using the marginal congestion component (MCC) of the locational marginal price (LMP) for the day-ahead electric market and the day-ahead market scheduled generation from 2015 through early 2018. The congestion rent will be calculated for Northern and Southern California separately with data obtained from the OASIS.

CPUC staff will provide the monthly frequency of congested hours in Northern and Southern California as well as the monthly average electricity price in Northern and Southern California. Furthermore, CPUC staff will provide correlation analysis between the daily natural gas price difference between SoCalGas Citygate price and PG&E Citygate Price, the daily available operating capacity as a proxy for pipeline outages, and the daily congestion rent revenue component of energy prices in Southern California and Northern California.

CPUC staff will also provide the monthly frequency of congested hours in Northern and Southern California, the monthly average electricity price in Northern and Southern California, and an analysis of the spread between on- and off-peak electricity prices in the CAISO area to shed light on the possibility for these conditions to recur in forecasted years.

CPUC staff also proposes to take as input the electricity prices and power plant dispatch profiles that result from the PCM analysis performed by CPUC staff in order to estimate implied market heat rate and possible congestion rents in forecasted future years (2020, 2025, and 2030).

The Congestion Rent Revenue is calculated as shown below:

$$CRRG = \sum_d^D \sum_h^H MCCh * GENh$$

CRRG is the congestion rent revenue from generation for a given month in a given year.

MCCh is the MCC for a given hour.

GENh is the scheduled generation for a given hour.

D is the number of days in a given month in a given year and d represent a given day.

In addition to CRRG, CPUC staff will provide the monthly frequency of congested hours in Northern and Southern California, the monthly average electricity price in Northern and Southern California, and an analysis of the spread between on- and off-peak electricity prices in the CAISO area.

CPUC staff also proposes to take as input the electricity prices and power plant dispatch profiles that result from the PCM analysis performed by CPUC staff in order to estimate

implied market heat rate and possible congestion rents in forecasted future years (2020, 20205, and 2030).

Table 4: Part 3 Data Sources

Variable	Data Source
Daily and monthly gas prices for: SoCalGas Citygate, PG&E Citygate, SoCalGas border	NGI
The dispatched quantity in Electricity Day Ahead Market- The dispatched quantity in Electricity Real Time Market	CAISO settlement data
Electricity Price and Generation	OASIS and SERVIM

### Proposed Data sources

To complete all three analyses outlined above, CPUC staff will collect data from various sources. Most of the data will be requested from SoCalGas and PG&E, while other data will be collected from Natural Gas Intelligence (NGI), ENVOY<sup>24</sup>, and OASIS.

CPUC staff will use several datasets such as daily storage inventory level by storage field in SoCalGas system, daily cooling and heating degree days, daily and monthly gas prices for several delivery points including SoCalGas Citygate, PG&E Citygate, SoCalGas border and Henry Hub, daily available operating capacity as a proxy for pipeline outages, daily operational flow order, future natural gas price and daily residential natural gas bill data.

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<sup>24</sup> ENVOY is SoCalGas’ Internet-based gas transportation management system  
<https://envoy.sempra.com>

## Appendix A

### Summary of I.17-02-002: Scenarios Framework Comments

The following is a summary of comments received in June 2018, prior to the July 31, 2018 Aliso Canyon Scenarios Framework Workshop held in Simi Valley, CA. Staff has considered all feedback and suggestions from the written comments, workshop, and follow-up stakeholder meetings in this final version of the framework document. Due to several repeated comments, staff has only responded to repeated comments as necessary.

<p>Name/Organization: Issam Najm, Ph.D.</p> <p>Category: Private citizen</p>	<p>Comments:</p> <ul style="list-style-type: none"> <li>• Hydraulic model should also look at what the system should look like without Aliso</li> <li>• Use an iterative process that identifies constraints</li> <li>• Arrive at what constraints need to be removed to allow eliminating Aliso Canyon</li> <li>• Do not use SoCalGas to conduct the hydraulic modeling</li> <li>• A period of 13 days is grossly insufficient to review and comment on this document – provide more time</li> </ul> <p>CPUC Responses:</p> <ul style="list-style-type: none"> <li>• Yes, the hydraulic modeling begins with Aliso Canyon set to zero injection/withdrawal. In the model, that translates to the Aliso storage field is “turned off” and only turned on as needed after modeling.</li> <li>• As mentioned during the July 31 Workshop, system constraints will be shared barring confidential information.</li> <li>• CPUC staff and Los Alamos National Laboratory will oversee the hydraulic modeling done by SoCalGas.</li> </ul>
<p>Name/Organization: CAISO</p> <p>Category: Balancing Authority</p>	<p>Comments:</p> <ul style="list-style-type: none"> <li>• Agrees with the general framework, but believes that CAISO power flow modeling should be used to inform both the hydraulic and production cost modeling</li> <li>• Recommends incorporating multiple transmission and/or</li> </ul>

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storage field outages in the hydraulic model

- Recommends reviewing electric reliability from both a “top-down” and “bottom-up” perspective. In the “top-down” approach, CPUC provides CAISO information on gas available for Electric Generation. In the “bottom-up” approach, minimum EG requirements from CAISO is an input to CPUC’s production cost and hydraulic modeling.
- Recommends considering western region impacts identified in WECC Gas-Electric Interface Study (referenced in comments)
- CPUC should conduct more granular analysis in hydraulic and production cost modeling. Recommends 30-minute steps rather than hourly
- Recommends 2020 rather than 2019 study year, because the studies are expected to be completed in the 2019 timeframe
- Concerned 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 Responses:

- Staff will model with an outage scenario (one pipeline outage), not multiple outages as CAISO recommends. Power Flow modeling is often done with a N-2 outage scenario, but hydraulic modeling is often done in a N-0 scenario, so a compromise is to study with N-1.
- Staff’s recommended approach is to undertake the “bottom up” sequence, where the Power Flow modeling (from both CAISO and LADWP, if LADWP data is made available) would happen first, then the constraints found there are implemented both in the PCM and Hydraulic Flow model.
- Staff will use CAISO data because CAISO data is publicly available and CAISO represents the majority electricity market in California.
- Peak hourly data will be used.
- Staff agrees, 2020 will be the first study year.

	<ul style="list-style-type: none"> <li>• Staff agrees, we are not expecting all the variables to be linear; we will make the necessary transformations to fit a good model.</li> </ul>
<p>Name/Organization: Center for Energy Efficiency and Renewable Technologies (CEERT)</p> <p>Category: Environmental organization</p>	<p>Comments:</p> <ul style="list-style-type: none"> <li>• Attachment A of the Updated Proposed Phase 1 Scenarios and the referenced “Unified I/A” document are insufficient to document the processes and data sources in the modeling effort</li> <li>• There are significant inconsistencies and ambiguities in the characteristics of the gas fleet to be modeled in Phase 1. CEERT believes the Unified I/A appears to be missing or mischaracterizing roughly 2500 MW of gas resources roughly in the Aliso Delivery Zone.</li> <li>• The Production Cost Modeling and Economic Modeling will ignore fixed cost changes beyond the purview of SERVVM and RESOLVE.</li> <li>• Staff should use the IEPR peak and total gas use forecasts, not the California Gas Report for peak gas use forecasts</li> <li>• Recommends the 42 MMT Core Case as more representative of the CAISO system in 2029</li> <li>• 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?”</li> <li>• The Production Cost Modeling and Economic Modeling must be scrapped and reconstituted from scratch. This should be the principal subject of the July 31 Workshop with publication of a proposed revised plan in the meantime.</li> </ul> <p>CPUC Responses:</p> <ul style="list-style-type: none"> <li>• Staff are using the 42 MMT Core Case from the IRP modeling in this proceeding and will also simulate all power plants in keeping with the Unified I/A, removing any distinction or reference to the 17 Aliso Canyon Plants.</li> </ul>

	<p>Staff is modeling all generators in WECC.</p> <ul style="list-style-type: none"> <li>• Staff is recommending use of the most updated California Gas Report for the gas forecasts</li> <li>• Staff are updating their assumptions in keeping with more recent "MasterFile" information and staff will also update to the 2028 Anchor Data Set to replace the 2026 Common Case.</li> <li>• Changes to enable closure of Aliso Canyon including gas efficiency, reduction in gas demand, and other ways to mitigate use of Aliso Canyon are in scope of Phase 2, not Phase 1.</li> <li>• Staff made considerable revisions to the Scenarios Framework documentation to better describe the models currently in the document.</li> </ul>
<p>Name/Organization: Environmental Defense Fund (EDF)</p> <p>Category: Environmental organization</p>	<p>Comments:</p> <ul style="list-style-type: none"> <li>• Concerned that the updated scenarios fails to capture the purpose of Senate Bill 380</li> <li>• Last year, EDF commented that the scenarios did not do enough to address changes in gas demand that would make Aliso Canyon closure feasible.</li> <li>• Updated Scenarios Framework assumes 17 power plants in LA Basin; however, a number of these plants are scheduled to shut down</li> <li>• Be explicit about assumptions as to which plants will continue through 2029</li> <li>• No indication the Updated Scenarios Framework will consider decreased swings in gas prices and that variability in prices is not consistent over time.</li> <li>• No indication that EDF's previous comments were considered in the hydraulic assessment</li> <li>• CPUC should ensure the modeling assumptions are transparent and available for public review</li> <li>• The Reliability Assessment: <ul style="list-style-type: none"> <li>○ Although an integrated model between the gas and electric side is not available, models of the intra-day gas system are available and should be</li> </ul> </li> </ul>

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used.

- Assessment should consider intra-day gas market rules, such as imbalance market
- Should identify the “full set of allowable operational actions” upon which the Reliability Assessment will be based
- Makes an unrealistic assumption about the limits of storage in non-Aliso facilities
- Framework relies too heavily on SoCalGas for critical inputs; need to do more to ensure data provided is reliable and unbiased
- At a minimum, SoCalGas’s determination of “plausible unplanned pipeline outage” must be subject to review by Los Alamos.
- The Feasibility Assessment:
  - Currently written, the Feasibility Assessment is conducted after determining a minimum Aliso requirement; it should inform the ultimate determination regarding a minimum Aliso storage requirement, if any
  - Elaborate on “alternative operational actions” that would reduce the Aliso requirement to zero; test the operational actions in the scenarios
  - Suggestion for an additional 76 scenarios for a total of 108 to examine different policy and demand-side possibilities
  - Proposed inputs ignore likely changes to gas demand
  - Assumptions for storage facilities, flowing gas supplies at receipt points are faulty; unplanned outages are double counted in Reliability Assessment
- Production Cost Model:
  - Unclear if the PCM will include the ability of non-Aliso storage assets to meet gas load
  - Fails to incorporate the ability of market rules to reduce the need for storage



- Consider conservation measures and economic growth in SERVVM model
- Economic Model:
  - Provides suggestions for assumptions that when cost of gas at the CA border exceeds the cost of stored gas, utilities will first draw from storage and that if Aliso is unavailable, gas will be bought on the spot market
  - Use NYMEX Forwards adjusted for negative basis to California
  - Must consider changes to gas demand as a result of CA's renewable energy requirements
  - Comparing to PG&E assumes the utilities otherwise operate the same, except for Aliso storage
  - Should not represent the results of tighter gas supply and costs associated as a definitive assessment

CPUC Responses:

Hydraulic Modeling Responses

- The “full set of operational actions” statement is still used in “Potential Future Analysis”. “Operational Actions” is used throughout the document. This wording is still important. The word “alternative” or “additional” was the source of the confusion.
- Due to the heavy lift to conduct each hydraulic model, staff will not be able to conduct 108 model runs. Among the 108 runs suggested, a quarter of these runs asks to investigate 2% scheduling, which is not the current market rule. In the future, CPUC staff may investigate other rules.
- Gas Demand: gas demand for electric generation (noncore, electric) is a result of PCM, therefore future changes in gas demand is incorporated (details are in the Unified I/A document). Core gas demand forecast is a 0.6% annual decrease as per the 2018 California Gas

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Report. Correspondingly, the forecasted winter peak decreases from 5,013 MMcfd in 2016 to 4,882 MMcfd in 2022.

- Operational actions: As mentioned in the scenarios framework, hydraulic simulations will show that it is *possible* to achieve a given scenario. However, the actions taken during the hydraulic simulations may not be translated to an “operational playbook”. i.e. gas operations may react differently on said peak day. Operational actions are best practices in pipeline operations (opening valves, ramping up compressors or maximize receipts while maintaining pipeline safety) plus any curtailments defined by the standard.
- Regarding assumptions about storage, staff finds the comment unclear. Working gas capacity is already historically defined and the changes are approved by DOGGR. On the other hand, withdrawal and injection capacities constantly change due to outages, wells being serviced or abandoned, or new regulations introduced by DOGGR.
- Feasibility assessment, by itself, cannot conclude whether the elimination of Aliso Canyon is possible. Feasibility assessment does not “assess” peaks or extreme peaks defined by the Reliability Standard. Furthermore, if the Reliability assessment shows a minimum required inventory for Aliso Canyon, then the conclusion is that Aliso Canyon is needed, and the question becomes whether this minimum inventory is feasible throughout a typical year.

#### PCM Responses

- Staff is modeling future study years based on the IRP dataset that is described in the Unified I/A document. The Unified I/A incorporates projected changes to the electric grid including efficiency and new renewables – matching the IRP scenarios in the 42 MMT Core Case
- PCM modeling for future years already includes the impact

	<p>Economic Model Responses</p> <ul style="list-style-type: none"> <li>• Input from the July 31 Workshop has been incorporated into this revision – staff is removing model #2</li> <li>• Staff prefers to use NGI gas pricing</li> <li>• Yes, comparing to PG&amp;E assumes that the utilities otherwise operate the same, except for Aliso storage. Staff intends to study that condition</li> <li>• Staff agrees, we are not representing the results of tighter gas supply and costs associated as a definitive assessment</li> </ul>
<p>Name/Organization: Sierra Club</p> <p>Category: Environmental organization</p>	<p>Comments:</p> <ul style="list-style-type: none"> <li>• 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.</li> <li>• Reference to the 17 natural gas-fired power plants does not recognize that several of the plants will be retired or are not approved</li> <li>• Modelling should capture gas demand under existing requirements and include alternative inputs that assume less gas than current forecast</li> <li>• Using the most recent California Gas Report does not capture the CEC’s savings from SB 350</li> <li>• Recommends a scenario where no retired gas units planned by LADWP and City of Glendale are replaced</li> <li>• Consider net reduction of gas-fired generation in Southern California Edison’s portfolio</li> </ul> <p>CPUC Responses:</p> <ul style="list-style-type: none"> <li>• Staff is using the 42 MMT Core Case from the IRP modeling in this proceeding, and will also simulate all power plants in keeping with the Unified I/A,</li> <li>• Staff is removing any distinction or reference to the 17 Aliso Canyon Plants because staff recognizes that</li> </ul>

	<p>SoCalGas supplies gas to all generators in Southern California. Staff is modeling all generators in WECC as detailed in the Unified I/A.</p> <ul style="list-style-type: none"> <li>• Future actions to reduce use of Aliso Canyon are in Phase 2, not Phase 1</li> </ul>
<p>Name/Organization: County of Los Angeles</p> <p>Category: Local government</p>	<p>Comments:</p> <ul style="list-style-type: none"> <li>• Hydraulic Modeling: <ul style="list-style-type: none"> <li>○ Pleaded LANL is assisting with hydraulic modeling, but maintains that SoCalGas should not participate in modelling</li> <li>○ Does not understand proposal to examine 1-in-10 and 1-in-35 events on a monthly basis; the County understands these as annual basis criteria</li> <li>○ Natural gas demand for future years must include effect of climate change and effect of state policies</li> </ul> </li> <li>• Production Cost Modeling: <ul style="list-style-type: none"> <li>○ “Day-matching” should be done by selecting EG dispatch days from SERVM’s data library and the 1-in-10 gas demand conditions</li> <li>○ To get Loss-of-Load Expectation (LOLE) and Loss-of-Load Hours (LOLH), need estimates of gas-powered generator curtailments every day; therefore, need to extrapolate from those estimates the impact of reduced Aliso on gas availability for each day of the simulated year. County has significant concerns about this step</li> <li>○ May consider if EGs as fully curtailable under 1-in-35 standard results in acceptable reliability of the electric system</li> <li>○ Concerns about the accuracy of SERVM’s dispatch of individual gas generators in the absence of a model representation of the transmission system</li> <li>○ Need for analysis of electric system under CAISO’s LCR program</li> </ul> </li> <li>• Economic Modeling</li> </ul>

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- Provided a regression equation for: SoCal natural gas price, SP15 price, and bill impact of Aliso Canyon's closure. (Note: refer to County of Los Angeles comments for equations and explanations)

CPUC Responses:

Hydraulic Modeling responses

- CPUC proposes a monthly hydraulic analysis because analysis (or at least 2 months representing winter and summer peak) is important since CPUC staff needs to investigate not only peaks, but also ramping rates. Furthermore, CPUC staff would like to obtain a minimum monthly gas schedule that would help determine if storage injections are on track of what is needed throughout a typical year.

PCM responses

- CPUC staff recognize the need for a transmission analysis to set up the PCM analysis, and thus have elaborated on the role of Power Flow analysis in the PCM section, proposing a "Bottom Up" approach.
- Staff will use the results of the hydraulic modeling to inform the amount of gas available for electric generation under the 1 in 35 extreme peak day design day scenario and perform PCM analysis to see if that would present a problem.
- More thought will be given to whether to extrapolate the 1 in 35 condition for an entire year, or how to implement a peak day constraint across the entire year.
- CPUC staff recognizes the difficulty of day matching between electric generator dispatch and gas use days for the hydraulic modeling. Staff has added a lot of detail to how that will be accomplished.

Economic Analysis Responses

Part A)

- Staff prefers the proposal in the Framework, due to use of much wider range of data, for example

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customer billing data for the same households over multiple years, which is not part of County of LA/E3's proposed analysis.

- CPUC staff believes our proposal is more comprehensive because our proposed regression analysis includes important variables such as weather and pipeline outages as measured by Operating Capacity.

Part B) and C)

- A PCM such as SERVM will be better suited to derive future generation dispatch and energy prices than the regression equation proposed by County of LA/E3 in their proposal. For analysis of historical data, staff prefers our proposal due to a more straightforward use of market data.
- County of LA/E3 proposes a regression analysis to determine the effect of Aliso closure on electricity prices, but staff believes the implied market heat rate analysis is superior due to more straightforward use of market data.

Part D)

- Staff disagrees, because LA County/E3 recommended an elasticity coefficient that is estimated at the aggregate level, missing differences between income classes and seasons of the year.
- LA County/E3 assumes the impact of Aliso closure is only due to change in the gas price, which is a bit simplistic. County of LA/E3 proposes to analyze effect of Aliso on customer bills by looking at change in gas price versus change in quantity of gas demand, without disaggregating by customer class, season, testing the effects of non-gas bill components, or trending of gas versus non-gas bill components. CPUC staff's proposal is preferable since there is a more detailed analysis of effect across customer classes and between similarly

	<p>situated customers which would isolate the effect of Aliso, or of being a SoCalGas customer, versus being a similarly situated PG&amp;E customer.</p> <ul style="list-style-type: none"> <li>• In response to County of LA/E3’s proposal, CPUC staff has added an analysis of the trend in gas charges versus non-gas charges to the proposal to surface the trends in these rate components.</li> </ul>
<p>Name/Organization: Southern California Publicly Owned Utilities (SCPOU)</p> <p>Category: Local government</p>	<p>Comments:</p> <ul style="list-style-type: none"> <li>• Specify the Aliso Canyon Withdrawal Protocol that will be assumed for the hydraulic modeling</li> <li>• Discussion of flowing gas supplies should conform to terminology used in SoCalGas’s Rule No. 30 governing transportation of customer-owned gas</li> <li>• The Updated Proposal states a difference between “scheduled flowing supplies” and “actual deliveries,” but under Rule No. 30 and NAESB standards, “scheduled quantities” are the quantities that flow through a receipt point or a backbone transmission zone for a customer’s account.</li> <li>• 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</li> <li>• Feasibility Assessment will assume pipeline outage consistent with a “historical record,” but history may not be an adequate guide. Line 235-2 remains out of service nine months after rupture, an inordinate amount of time.</li> <li>• Unclear rationale about why only four scenarios total are run in 2024 and 2029</li> <li>• Clarify that the Summer 2018 715 report will be the starting point for the Production Cost Modeling</li> <li>• Explain why Economic Modeling is limited to CAISO and not LADWP and IID</li> <li>• If actual data for 2019 are available, use actuals</li> </ul>

	<p>CPUC Responses:</p> <ul style="list-style-type: none"> <li>• The Aliso Canyon Withdrawal Protocol issued on November 2017 is still the most current one.</li> <li>• Staff has updated usage of scheduled quantities and receipt point utilization</li> <li>• Staff will use CAISO data because CAISO data is publicly available and CAISO represents the majority electricity market in CA</li> <li>• CPUC staff has updated assumptions and terminology usage</li> <li>• The correct combination of outages and utilization factors is still being assessed by staff. Staff agrees that historical values of utilization factors (receipts or zone) may be biased because of outages; therefore, a representative time period must be used.</li> </ul>
<p>Name/Organization: The Utility Reform Network</p> <p>Category: Consumer advocacy organization</p>	<p>Comments:</p> <ul style="list-style-type: none"> <li>• Framework should be useful to evaluate reliability and cost issues posed by loss of some or all of Aliso Canyon facility</li> <li>• No comments on Hydraulic Modeling</li> <li>• Response to Production Cost Modeling questions 1-3: Production cost models may be good directional indicators of impact of cost, but additional effort would be required to convert cost impacts to impacts on utility revenue requirement</li> <li>• Response to Production Cost Modeling question 4: doubts this is the best means, instead suggested that a general gas delivery constraint be imposed on the units affected by loss of Aliso.</li> <li>• Response to Production Cost Modeling question 5: recommends ED consider using SERVIM to estimate EG gas demands by simulating a smaller interval (such as a day or a week) using the electric load inputs corresponding to a 1-in-10 and 1-in-35 condition</li> </ul>



	<ul style="list-style-type: none"> <li>• It is not clear how information from Economic Modeling would be used</li> <li>• The word “algorithm” on page 25 should be “logarithm”.</li> <li>• Implied heat rates in Economic Modeling should consider CAISO GHG bidding and pricing rules, or explain why not</li> <li>• Response to Economic Modeling questions 1-3: These questions are reasonable and appropriate.</li> <li>• Response to Production Cost Modeling questions 4-6: No opinion</li> </ul> <p>CPUC Responses:</p> <ul style="list-style-type: none"> <li>• On Production Cost Modeling comments: yes, the model will be used as suggested</li> <li>• TURN suggests general gas delivery constraint in lieu of unit by unit inputs. Staff is concerned that some of the impacts of Aliso curtailment (not just lack of gas, but lack of quickly delivered gas) cannot be modeled as TURN suggests, but staff is open to suggestion. Staff are intending to model <i>at least</i> what TURN suggests, but may also model other ways too.</li> <li>• On Economic Modeling: staff has removed model #2 and believe the other three are still important.</li> <li>• By using CAISO OASIS historic market clearing prices, the data already includes the three components of the price (GHG price, congestion, and the underlying energy price) subject to CAISO bidding rules</li> </ul>
<p>Name/Organization: Magnum Energy Midstream Holdings, LLC</p> <p>Category: Natural gas storage company</p>	<p>Comments:</p> <ul style="list-style-type: none"> <li>• The framework is built on overly optimistic assumptions about operational capabilities of the SoCalGas system.</li> <li>• No provision for modeling the potential reliability benefits from independent gas storage and storage-based services</li> <li>• Reliability Assessment: <ul style="list-style-type: none"> <li>○ Agrees with approach to “use full implantation of</li> </ul> </li> </ul>

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all allowable operational actions to achieve the required system performance.”

- Some proposed assumptions about the SoCalGas system are overly optimistic; could end up validating minimum storage requirements that are significantly lower than what’s needed
- 95% receipt point utilization rate is not realistic, staying within historical range, such as 80%, is more realistic
- Highly optimistic assumption that system outages never involve more than one major storage or transmission asset; Magnum urges framework to include planned and unplanned outage scenario
- Staff suggested additional actions may be taken beyond the set of operational actions defined; Identify at least one action that may be modeled
- Magnum should be used as a basis for an “additional actions” scenarios in the framework
- Feasibility Assessment:
  - Framework states that Feasibility Assessment “may” be done; Magnum suggests they should be done
  - 95% receipt point utilization rate is not realistic, suggests 70% for Feasibility Assessments
- Economic Modeling:
  - It is not clear what data will be used for NP15, SP15, and day-ahead market electricity prices
  - Implied Heat Rate should be assessed on an hourly basis using hourly day-ahead LMP prices from OASIS

CPUC Responses:

- Usage of receipt point utilization has been corrected and zonal transmission capacity utilization is introduced instead.
- Staff has updated this revision to state price data from NGI and Platts will be utilized

	<ul style="list-style-type: none"> <li>• Staff agrees with hourly day-ahead LMP prices from OASIS,</li> <li>• For historical analysis, staff will use the CAISO hourly LMP market data. For future forecasted years, the same data will come from the PCM modeling. PCM analysis will be performed by CPUC staff in order to estimate implied market heat rate and possible congestion rents in forecasted future years (2020, 20205, and 2030).</li> </ul>
<p>Name/Organization: SoCalGas</p> <p>Category: Gas Utility</p>	<p>Comments:</p> <ul style="list-style-type: none"> <li>• Because of the importance of this determination, Phase 1 should be resolved through hearings, evidence, and a Commission decision</li> <li>• Supports that “[t]he inputs into the models will be based on demand projections that incorporate all the increases in renewables, conservation, and energy efficiency currently required by California legislation.”</li> <li>• Scenarios should incorporate current DOGGR operational and safety requirements</li> <li>• Confirm that in Phase 2 parties will not be barred from contesting</li> <li>• SoCalGas’s performance as a hydraulic modeler should not be interpreted as SoCalGas’s agreement or endorsement of the Commission’s hydraulic modeling approach and assumptions</li> <li>• Clarify the order of the modeling for the scenarios</li> <li>• On page 7, it is incorrect to state “that gas withdrawn from Aliso Canyon “does not compete with the flowing supply for pipeline transportation.”</li> <li>• Clarify how Energy Division will document the modeling process and how it will determine if a scenario was “successful”; for example, linepack is fully recovered</li> <li>• Define “success”</li> <li>• Explicitly state what output is required from each simulation</li> <li>• Reliability Assessment should include contingency</li> </ul>

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storage supplies to address risks of SoCalGas system being dependent on out of state deliveries of gas; also include reduction in supplies from interstate pipelines

- Aliso Canyon is a critical component throughout the western United States; loss of storage in California can impact prices and reliability in neighboring states
- The “Polar Vortex” in 2014 caused higher-valued markets east of California and receipts into SoCalGas fell; at the time, prices were approximately \$30/MMbtu at Rockies and \$12/MMbtu at SoCal-CityGate. SoCalGas withdrawals reached 2.5 billion cubic feet
- Exhibit A attached to SoCalGas comments is the June 2018 Western Interconnection Gas – Electric Interface Study, which found that operational limitations imposed on Aliso Canyon highlight issues; system reserve margins expected to be tight through 2026; natural gas demand across Western Interconnection to increase by 30% by 2026
- Therefore, analysis of benefits of Aliso Canyon should include impacts outside of Southern California
- Modeling in near term should be done for 2020
- Running a hydraulic model is no small undertaking, with each one taking 1-3 weeks to run; Energy Division should develop a process to document modifications or additional actions to a scenario
- It is unreasonably high to assume a 95% receipt point utilization. Historical averages are closer to 80-85% utilization
- To complete hydraulic modeling, SoCalGas will need hourly demand for each specific plant
- Energy Division should provide additional scenario analysis of emergency situations, potential upstream supply disruptions, and unexpected loss of electric imports
- Reliability Assessment
  - “Preference” to operations of non-Aliso facilities is unclear and does not reflect current electric dispatch as determined by CAISO

- Clarify storage injection/withdrawal and inventory assumptions for non-Aliso fields. Confirm only maximum tubing-only-flow storage withdrawal
- For the 1-in-10 year analysis, a 1-in-10 Dry Hydro year load should be used
- No restrictions on generators within the basin should be applied to derive electric demand
- Clarify whether the minimum gas storage schedule reflects withdrawal performance declines that are associated with inventory decreases, and injection performance declines that are associated with inventory increases at each storage field.
- On page 14, clarification is needed as to what is the “maximum available scheduling capacity”
- To determine range of unplanned outage, update table in the 2016 Aliso Canyon Risk Assessment Technical Report (Table 3) from the 2013-2015 period to include the latest line outages in 2017 (Line 3000, 4000, 235-2)
- 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
- Description of how unplanned outages will be applied should be clarified. Effect of unplanned outage should be assessed on the system before determining whether withdrawals from Aliso Canyon are needed
- At the end of Reliability Assessment, “additional actions” requires further definition and explanation
- Feasibility Assessment:
  - On page 18: expand on assumption of flowing supply available assumed to be 5% lower relative to maximum available scheduling capacity

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- Build injection curves into Feasibility Assessment
  - Incorporate known planned outages
  - On page 18-19, clarify what alternative operation actions or supply sources considered
  - Production Cost Modeling:
    - Aliso inventory level should begin with 68.6 Bcf, as determined by DOGGR; scenario where storage withdrawal is maximized allows comparison against economic benefit of gas storage
    - Does not identify the demand, import capacity, outages, and wildfire risks in assumptions
    - For the 1-in-10 year analysis, a 1-in-10 Dry Hydro year load should be used
    - Project hourly dispatch of all power plants in Southern California, not only the 17 plants
    - LOLE should be expanded to a broader analysis outside of Southern California system
    - Clarify how SERVM and hydraulic modeling will be integrated and how hydraulic modeling constraints and/or curtailments will be incorporated in Production Cost Modeling
  - Economic Modeling
    - Additional costs to meet core customer's design day in lieu of Aliso Canyon are not mentioned
    - Seasonal gas cost differentials are not accounted for; SoCalGas customers purchase gas supplies in lower priced non-peak season to use in higher priced winter
    - Recommends using a gas market fundamental model to project future gas prices; examine historical NYMEX and forward bases
    - Does not account for direct and indirect impacts on electricity prices associated with lack of Aliso Canyon beyond Southern California
    - Economic impacts are not limited to gas and electricity; higher gas and electricity prices will reduce economic activity in Southern California
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- Does not capture impact that removal of Aliso Canyon would have on the average price of gas; removing Aliso reduces supply competition and increases prices
- Does not consider economic cost associated with decreased reliability (e.g., impact of curtailments and brownouts)
- Clarify how results of gas price volatility model will be incorporated into Economic model; explain relationship between volatility model and electric and gas cost outputs
- Methodology looking at historical heat rates for 2015, 2016, and 2017 may not accurately capture the impacts due to mild winters over that period; based it on a longer historical sample
- Recommends a scenario where Aliso Canyon is opened to the inventory level consistent with its maximum allowable operating pressure for each of the years modeled.
- Volatility Analysis
  - Does not capture Aliso Canyon's cost savings from seasonal price differentials
  - Clarify what methodology will be used to determine potential impact of higher volatility on consumer gas costs
- Factors that Mitigate Natural Gas Storage
  - Clarify purpose of this analysis and how it will be conducted
- Impact of Natural Gas Storage on Ratepayers
  - Analysis is too narrow to provide insights on whether the period Aliso Canyon had a temporary moratorium increased bills; customer bills, by design, are relatively stable over time
  - Analysis should incorporate controls for factors to isolate the impact of storage on customer's bills.
  - An alternative framework to examine future consumer bill impacts should be used, include

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estimating economic impacts on different classes of natural gas customers and aggregating to derive annual cost of service increase and customer bill impact based on standard rate assumptions.

- Implied Heat Rate and Congestion Rent Analysis
  - Proposed historical analysis will be impacted by weather and other factors; impact is better reflected by future wholesale market price project with and without Aliso Canyon
  - Use a model that is capable of projecting electricity prices with and without Aliso Canyon, such as PLEXOS

CPUC Responses:

- Guidelines for a successful model run have been included in this revision – provided more definition of “linepack”.
- Hourly demand from “Minimum Local Generation” scenario will be used.
- Staff bolstered description of the interaction between the PCM and hydraulic models in the Scenario Framework.

Hydraulic Modeling

- Staff will attempt to use non-Aliso storage first, then use Aliso only when needed in the hydraulic model. The goal is to take Aliso out of the model to see if there are reliability problems. This is not meant to mimic CAISO operations.
- Staff provided additional analysis of receipt point utilization, backing up staff’s forecast of utilization at various receipt points. Staff is comfortable with the assumptions, which are closer to those suggested by SoCalGas. Outages on pipelines appear to affect utilization, primarily in moving utilization from constrained points to unconstrained points, and that affect shows up in the historical record.
- Aliso Canyon inventory will begin at zero in order to fulfill SB 380

Production Cost Modeling



- Staff is using the 42 MMT Core Case from the IRP modeling in this proceeding, including specification of sources for electricity demand data, operating parameters of power plants, and import capability between regions in the model. No specific handling for wildfires is in the PCM analysis.
- Staff is simulating a range of weather years from 1980 to 2014, thus not restricted to dry hydro years. Simulating all weather years and calculating the weighted average outputs.
- The PCM analysis will provide simulated output for all power plants in WECC, consistent with the Unified I/A, removing any distinction or reference to the 17 Aliso Canyon Plants. Staff is modeling all generators in WECC.
- Staff is producing LOLE and production cost metrics for the entire CAISO area as well as other areas in California such as LADWP

#### Economic Modeling Questions

- We removed analysis #2 – Factors that impact natural gas storage decision
- Staff is modeling economic conditions from 2015 through the current month, primarily to locate the impact of Aliso curtailment. Longer historical records may be used, depending on data availability on the CAISO OASIS website. Staff will be evaluating earlier data sets to see if that data is complete.
- Staff does not believe we need to evaluate a fundamental model, as that was needed for the analysis #2 that we removed. Staff intends to use NGI data for price projections, without using a fundamental model.
- In terms of volatility, the method intends to use a linear regression model, as explained in the paper. If the data analysis shows there are non-linear effects, we may reconsider the regression, but we will analyze the data first.
- Considering impacts to economic activity in Southern California is beyond the scope of the questions we are

	<p>trying to answer.</p> <ul style="list-style-type: none"> <li>• This modeling effort will strictly adhere to the scope of SB 380.</li> <li>• Staff is intending to use SERVVM to forecast energy prices in forward years. The revised Scenarios Framework includes this explained</li> </ul>
<p>Name/Organization: Southern California Edison</p> <p>Category: Electric Utility</p>	<p>Comments:</p> <ul style="list-style-type: none"> <li>• Recommends publishing the dispatch of each generating unit in the LA Basin resulting from Production Cost Modeling; useful for the Participating Transmission Owners to assess the impacts and offer potential mitigation</li> <li>• Mass constraint for a group of generators should be preferred to allow more efficient generator dispatch and resource sharing in the Production Cost Model</li> <li>• Production Cost Modeling should include 2020 and 2021 as additional years; considering OTC compliance dates and staggered on-line dates of new LA Basin resources, it may be helpful to see potential impact on rates/reliability in those years</li> </ul> <p>CPUC Responses:</p> <ul style="list-style-type: none"> <li>• 2020 will be the first year modeled, followed by 2025 and 2030</li> </ul>