

## **EXHIBIT A**

### **SCOPE OF WORK**

#### **A. Introduction**

The California Public Utilities Commission (CPUC) is the state agency that regulates services and utilities, protects consumers, safeguards the environment, and assures Californians' access to safe and reliable utility infrastructure and services at just and reasonable rates. On October 23, 2015, SoCalGas' Aliso Canyon natural gas storage facility began to leak natural gas from its underground storage facility located near Porter Ranch, California. On February 9, 2017, pursuant to Senate Bill 380, the CPUC opened an investigation (I.) [17-02-002](#) to determine the long-term feasibility of minimizing or eliminating the use of the facility while still maintaining energy and electric reliability for the Los Angeles region and just and reasonable rates in California. The CPUC's Energy Division has since engaged in a comprehensive modeling and stakeholder feedback process to achieve this objective and is currently in Phase 2 of (I.) 17-02-002. The original schedule of the investigation planned that if the Phase 2 modeling shows that Aliso Canyon cannot be eliminated without jeopardizing reliability or rates, the CPUC would open a subsequent Phase 3 to examine what infrastructure modifications or gas demand changes could be deployed cost effectively to either further minimize or entirely replace the need for Aliso Canyon.

On November 18, 2019, California Governor Newsom issued a letter to the CPUC requesting that the CPUC "engage an independent, third-party expert to identify viable alternatives to the Aliso Canyon gas storage facility and scenarios that can inform a shorter path to closure." The Governor's letter has caused CPUC staff to accelerate Phase 3 and begin it while Phase 2 is still underway. On December 20, 2019, the CPUC initiated a new Phase 3 in (I.) 17-02-002 to engage a third-party expert consultant to develop scenarios, conduct implementation assessments, and produce a report on how the Aliso Canyon field could be entirely replaced no later than two different planning years—2027 and 2045—without negatively impacting energy reliability in the region and while still preserving just and reasonable rates in California.

The CPUC is seeking an expert Consultant to perform the tasks and deliverables identified within this scope of work.

#### **B. Statement of Work**

The CPUC requires the services of an expert consultant to undertake an examination of the following two issues:

1. How can the services presently provided by the Aliso Canyon field be met if the field were to be eliminated by the two planning years of 2027 and 2045? The planning years are meant to serve as the latest possible dates for replacement of Aliso Canyon. Under each scenario analyzed, replacement may occur before the final planning year. Scenario analysis and recommendations may also include any mix of the following, in addition to other solutions:

- a. Demand reduction and demand management programs that reduce demand incrementally beyond programs presently in place and/or assumed in the demand forecast;
  - b. Replacement of gas transmission pipelines or the construction of new gas transmission pipelines or compressor stations;
  - c. Replacement of gas-fired electric generation with resources that are carbon neutral or act to integrate renewable energy; and
  - d. Expansion of electric storage.
2. What is the feasibility of each proposed plan, technology, or mix of resources identified including the estimated time needed for construction or implementation? Elements of the feasibility assessment will include at a minimum the following:
- a. Estimated cost of each proposed plan;
  - b. Potential impacts on gas commodity costs;
  - c. Potential impacts on electric and gas reliability;
  - d. Commercial availability;
  - e. Risk assessments;
  - f. Timeframe to develop and implement necessary technology(ies); and
  - g. Regulatory constraints.

The baseline analysis will consider the following:

1. The 2030 Integrated Resource Plan (IRP) Reference System Portfolio adopted by the Commission in compliance with Senate Bill (SB) 350 (emissions, reliability, least cost) (proposed decision expected February 2020);
  - a. All present demand reduction and demand management programs as represented in the last approved Integrated Energy Policy Report (IEPR) load forecast;
2. CPUC-verified inputs and results from the SB 380-mandated studies currently being conducted in (I)17-02-002, including:
  - a. Peak day and extreme peak day gas service needs for core and non-core customers,
  - b. Rate and cost impact study results showing cost impact to core customers of minimizing or closing the storage field,
  - c. Hydraulic modeling results showing impact on gas flows and pressure within the Southern California Gas System of minimizing or closing Aliso Canyon, and
  - d. Production cost modeling results showing the impact of minimizing or closing the storage field on electric generation in Southern California, including power flows between Los Angeles Department of Water and Power and the California Independent System Operator.

3. Findings and conclusions from reports examining the natural gas transition:
  - a. 2018 California Council for Science and Technology report, Long-Term Viability of Underground Natural Gas Storage in California, <https://ccst.us/reports/natural-gas-storage/>
  - b. CEC/E3 PATHWAYS studies and updates, e.g. June 2018 Deep Decarbonization in a High Renewables Future: Updated Results from the California PATHWAYS Model, <https://www.ethree.com/wp-content/uploads/2018/06/Deep-Decarbonization-in-a-High-Renewables-Future-CEC-500-2018-012-1.pdf>
  - c. September 2019 Gridworks, California's Gas System In Transition <https://gridworks.org/wp-content/uploads/2019/09/CA-Gas-System-in-Transition.pdf>
  - d. October 2019 (Draft) California Energy Commission, Natural Gas Distribution in California's Low-Carbon Future, <https://ww2.energy.ca.gov/2019publications/CEC-500-2019-055/index.html>
  - e. June 2018 Western Electricity Coordinating Council, Western Interconnection Gas – Electric Interface Study. <https://www.wecc.org/Administrative/WECC%20Gas-Electric%20Study%20Public%20Report.pdf>

Scenario planning will use at least the following:

1. The replacement of Aliso Canyon by the two planning years 2027 and 2045. Scenario analysis may result in recommendations that plan for Aliso Canyon to be entirely replaced before 2027 and 2045.
2. Sensitivities developed for the IEPR load forecast that include aggressive projections for all customer/behind-the-meter programs.
3. Sensitivities that include new programs not yet incorporated in the IEPR load forecast, such as the CPUC's fuel substitution rule within energy efficiency (for more information on fuel substitution in energy efficiency, see <https://www.cpuc.ca.gov/General.aspx?id=6442463306>).
4. Fourth Climate Assessment projections for temperature, sea level rise, and other climate-related variables relevant to Southern California (<http://climateassessment.ca.gov/>).
5. A geospatial depiction of gas transmission pipelines that would be needed to transport natural gas using assumptions about reduced core and non-core customer demand and additional incremental electric generation resources. Gas transmission pipeline data can be gathered from CPUC staff as well as the California Energy Commission's (CEC) California Natural Gas Pipeline and Station database (<https://cecgis-caenergy.opendata.arcgis.com/app/cad8dec8bb4045d0a841573ce3ac81f5>).

The Contractor will have the benefit of leveraging the initial modeling results conducted in Phase 2 by the Commission's Energy Division about the impacts to residential customers and electric generation customers if Aliso Canyon were to be reduced or eliminated.

The Contractor will also be able to use the assumptions incorporated into the Phase 2 modeling effort about declining gas usage and the achievement of a lower-greenhouse gas (GHG)-emission portfolio as set out in the CPUC's Integrated Resources Plan, which represents the electric resources and transmission needed to help the state reduce economy-wide GHG emissions to 40 percent below 1990 levels by 2030.

Finally, the Contractor will be able to draw on the assumptions of future energy savings and load modification from the CPUC's energy efficiency, demand response, building decarbonization, building electrification through fuel switching, rooftop solar, electric vehicles, and other demand reduction and modification programs. These assumptions, out to the year 2030, can be found in the IRP (<https://www.cpuc.ca.gov/General.aspx?id=6442462824>).

### C. Contractor Tasks and Deliverables

#### Task 1: Project Management

**Deliverable 1:** Upon contract execution, attend an in-person kick-off meeting with CPUC staff in San Francisco, CA and provide a Gantt chart detailing the project schedule with milestones and deliverables.

**Deliverable 2:** Starting two weeks after contract execution, provide every other week status updates to the CPUC project manager with an updated Gantt chart detailing progress along the project schedule and addressing any concerns or issues that may come up.

#### Task 2: Develop assumptions, scenarios, and a modeling/analysis plan

Upon contract execution, the Contractor shall begin review of the baseline analysis and scenario planning data and reports listed in section B Statement of Work above and develop detailed assumptions and scenarios and a detailed modeling/analysis plan to be adopted by CPUC.

**Deliverable 1:** Within two months of contract execution, submit a draft report to the CPUC that identifies and explains preliminary assumptions, scenarios, and the modeling/analysis plan. Additionally, provide anticipated data needs to the CPUC to allow data preparation to begin.

**Deliverable 2:** Within two weeks of draft report submission, participate in a public workshop in the Los Angeles, CA area focused on gathering feedback on the proposed assumptions and scenarios and modeling/analysis plan.

**Deliverable 3:** Within three weeks of the public workshop, use the comments and feedback to submit a final written report on the assumptions and scenarios and the modeling/analysis plan to the CPUC for adoption.

### Task 3: Create Final Report

Immediately upon CPUC adoption of the final assumptions and scenarios and the modeling/analysis plan, the contractor will begin the modeling and analysis work to create a final report detailing all scenarios and plans proposed and answering the questions of both main issues described in section B Statement of Work above. The final report shall include a risk assessment for each potential solution or recommendation. At a minimum, the risk assessment must include the degree to which the technology(ies) and solutions may have an impact on reducing the need for Aliso Canyon, as well as a potential risk of failure for each recommendation.

**Deliverable 1:** By approximately August 15, 2021, submit a draft report in Microsoft Word and .PDF format to the CPUC for review and comment. The CPUC will provide comment within three weeks.

**Deliverable 2:** Within two weeks of receiving CPUC comments, participate in a public workshop in the Los Angeles, CA area to present the draft report with findings and conclusions.

**Deliverable 3:** Taking into consideration the feedback from CPUC and the public workshop, submit a final report and executive summary to the CPUC by approximately December 1st, 2021, detailing all scenarios and plans proposed and answering the questions of both main issues in a Microsoft Word and .PDF format.

## **D. Proposal and Resumes**

The Contractor shall accomplish the tasks and deliverables outlined the section C according to the proposal submitted by the contractor which is made a part of this agreement as attachment A-1 FTI Consulting Inc. Proposal and Resumes.

## **E. Location**

Work shall be performed primarily at the Contractor's office, although in-person meetings with CPUC staff located at offices in San Francisco, Sacramento, or Los Angeles, CA may be scheduled as necessary. This may include up to four in-person meetings.

## F. Time

The contract will be for an eighteen-month term following contract execution with two six-month options to amend and extend the agreement for a total of one additional year.

Estimated contract execution date is June 30th, 2020.

## G. Responsibilities

### 1. Contractor Responsibilities

- a. Assign a project manager to act as the point of contact for this contract who will oversee Contractor's team and ensure execution of deliverables according to the schedule.
- b. Provide CPUC staff with all requested data used in the contractor's analysis. This may include modeling software files and spreadsheets.

### 2. CPUC Responsibilities

- a. Provide access to business and technical documents as necessary for the contractor to complete the tasks identified in this contract.
- b. Serve as a liaison between the contractor, SoCalGas, and other state agencies.
- c. Organize logistics and locations for public workshops.
- d. Make publicly available all underlying data, methods, and analysis used by the Contractor to perform the scope of work, to the extent possible, while maintaining confidentiality of any proprietary modeling software, market-sensitive information, or other privileged information.
- e. Provide prompt feedback to the Contractor on the draft plans and report.
- f. Solely approve all deliverables according to the following acceptance criteria:
  - i. There must be a signed acceptance document by the CPUC Contract Manager for each deliverable before invoices can be processed for payment.
  - ii. Deliverables must be in the format specified in the Statement of Work.
  - iii. If a deliverable is not accepted, the CPUC Contract Manager shall provide the rationale in writing within 10 business days of receipt of the deliverable.

## H. Conflict of Interest

### 1. Definitions

For purposes of this Agreement, "conflict of interest" means:

- a) a conflict of interest as defined in this RFP or any resulting Agreement;

- b) Any activity or interest prohibited by any applicable Federal or State law, including the Political Reform Act, relating to conflicts of interest and any regulation under them;
- c) Any financial interest or relationship that may impair the ability of the individual or firm to deliver fair unbiased work for the State;
  - i. A relationship may include any business position such as a director, partner, officer, trustee, employee, or any position of management with any of the Covered Entities or any parent, subsidiary, or affiliate thereof.

“Team Member” includes a) any firm (either as a prime or sub-contractor) whether incorporated or not, including a sole proprietorship (“Firm Team Member”); and b) any individual, whether an employee, independent contractor or other (“Individual Team Member”) if the Firm Team Member or Individual Team Member is performing or supervising work under this RFP or any resulting Agreement that is expected to involve the exercise of judgment.

“Covered Entities” means: all CPUC-regulated entities or parties to CPUC Proceeding #I.17-02-002.

## 2. Terms and Conditions

- a) During the duration of the resulting Agreement a Team Member shall not have, or engage in, any activity that would constitute a Conflict of Interest.
- b) It is the responsibility of Contractor Delegate’s Program Manager to manage any changes or newly identified potential Conflicts of Interest that arise during the course of the project and notify the CPUC’s contract manager promptly of any potential Conflict of Interest. The CPUC may, at its option, direct termination of any individual or firm or this Agreement, if such a Conflict of Interest is found.
- c) Each Team Member shall comply with any and all applicable conflict of interest laws and the conflict of interest terms of this RFP or any resulting Agreement. Upon request, each Team Member shall provide additional information as directed by the CPUC's Project Manager in order to comply with state conflict of interest requirements or to allow the CPUC to evaluate potential conflicts of interest.
- d) The Commission may score the proposers based on the presence or absence of potential conflicts.
- e) Contractor’s Contract Manager shall ensure that all Individual Team Members whether identified or not, follow the provisions of this RFP or resulting Agreement.

3. Required Disclosures

This section discusses disclosures that must be made by the proposer and any Firm Team Members.

A number of conditions may render the proposer or Firm Team Member unable to give impartial, technically sound, objective assistance and advice that might result in a biased work product. In addition, the Commission wishes to avoid having confidential information related to this work being used to provide an unfair competitive advantage to a regulated entity or its competitors. The following disclosures are required in order to properly evaluate and judge the Proposer and each Firm Team Member and to avoid termination and/or controversy at a later stage.

- a) Current contracts/employment with, or active proposal(s) before, any of the Covered Entities or any parent, subsidiary, or affiliate thereof. Provide the total amount of payments, duration and nature of service. In addition, indicate if any Individual Team Member is working on or is expected to work on any of these contracts.
- b) Prior contracts during the last three years with any of the Covered Entities or any parent, subsidiary, or affiliate thereof. Provide the total amount of payments, duration and nature of service. In addition, indicate if any Individual Team Member worked on those contracts.
- c) Any current subcontracts with any of the Covered Entities or any parent, subsidiary, or affiliate thereof. Provide the total amount of payments, duration and nature of service. In addition, indicate if any Individual Team Member is working on these contracts or is expected to work on any of these contracts.
- d) Any investment in, or joint venture, partnership or similar arrangement with, any of the Covered Entities or any parent, subsidiary, or affiliate thereof. For investments list only current investments; for a joint venture, partnership or similar arrangement list those existing within the past three years. List the entity's name, the nature, scope and duration of the business arrangement and the total monetary value.
- e) A proposer or Firm Team Member who is employed by a party, other than a state agency, in Investigation 17-02-002 or the successor proceeding(s) to that proceeding, or the successor proceeding(s) to those proceedings for the purpose of preparing information or otherwise advising the party regarding issues raised in those proceedings, must disclose its contracts with that party relating to those proceedings. Provide the total amount of payments, duration and nature of service.



- f) For each Individual Team Member any work he or she has done for the CPUC during the past three years. Identify the CPUC contract involved, briefly describe the work performed, the total number of hours of work performed on the contract, and the period of time over which the individual performed that work. Note that additional information about Individual Team Members who have previously worked for the CPUC may be required in order to evaluate the proposal in response to the RFP for conflicts of interest.

Failure to disclose the above-mentioned could be grounds for disqualification.

**I. Contact Information**

The Contract Managers for the term of this agreement will be:

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|---|---|
| State Agency:<br>California Public Utilities Commission     | Contractor:<br>FTI Consulting Inc.  |
| Name: Christina Ly  | Name: Matthew Decourcey   |
| Phone: (213) 266-4726                                       | Phone: (617) 897-1526   |
| Email: <a href="mailto:cly@cpuc.ca.gov">cly@cpuc.ca.gov</a> | Email: <a href="mailto:matthew.decourcey@fticonsulting.com">matthew.decourcey@fticonsulting.com</a> |

## 7. Scope of work

We propose a scope of work that consists of eight separate tasks, each of which are described below. With the exception of the first task, which is strictly administrative, each of the tasks can be divided into two separate workstreams, one each corresponding to the two main questions posed in Section I.B of the RFP:

*First*, what are the investments in infrastructure that California can make that would facilitate more rapid closure of the Aliso Canyon facility? And,

*Second*, which of the options available are the most beneficial for California ratepayers?

Among most prominent of the tools we will use to develop analyses to answer these questions is a proprietary suite of gas and electric modeling tools, which is described in detail in Section 8. Summarized at a high level, the modeling suite consists of three primary applications:

- A **Power Market Model**, which is a customized version of PLEXOS, a chronological-dispatch model we license from Energy Exemplar, which we will use to simulate the dispatch and operation of the California electric market;<sup>2</sup>
- Our **Gas Delivery Model**, which is built using Gregg Engineering's NextGen modeling platform, that we will use to analyze the physical flow of gas into and within the California market to analyze deliverability constraints and reliability issues; and
- A **Gas Market Model**, for which we will utilize GPCM, the industry-standard tool for the simulation and analysis of gas markets, along with a proprietary database, allowing us to estimate the gas price impacts of the various infrastructure changes we postulate.

Below, for each of the two workstreams, we briefly summarize our view of the question to be answered and explain in detail the tasks that comprise approach to developing an answer. Preliminary timelines are also provided for the completion of each task.

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<sup>2</sup> To the extent required, the Project Team will also use the ENELYTIX, another platform in widespread use for applications of this type, to examine the implications of the results developed using PLEXOS, including analyses of nodal prices, transmission constraints, and hourly dispatch patterns for selected generators. Key model features are described in Section 8. FTI has extensive experience with both models to conduct studies for clients.

**Table 2. Proposed Tasks**

|                     |          |  |
|---------------------|----------|--|
|                     | <b>1</b> | <b>Kickoff Meeting</b><br>Discussions of project management, timelines, and communications protocols                                   |
| <b>Workstream 1</b> | <b>2</b> | <b>Baseline Scenarios</b><br>Development and execution of models under business-as-usual conditions                                    |
|                     | <b>3</b> | <b>Alternative Scenario Specifications</b><br>Specifying packages of investments California could make to address reliability issues   |
|                     | <b>4</b> | <b>Distribution of the Modeling Plan</b><br>Seek feedback and approval for modeling assumptions and methods from CPUC and stakeholders |
|                     | <b>5</b> | <b>Modeling and Evaluation of Alternatives</b><br>Execute models with approved inputs and analyze results                              |
| <b>Workstream 2</b> | <b>6</b> | <b>Electric Reliability Analysis</b><br>Confirm the stability of the gas-electric interface  |
|                     | <b>7</b> | <b>Regulatory Constraints Analysis</b><br>Determine whether regulatory paradigms appropriately support new investment                  |
|                     | <b>8</b> | <b>Reporting</b><br>Finalization of publication of our results and recommendations   |

Task 1. Kickoff Meeting and Project Management.

Within two weeks of our engagement, the Project Team will lead a Kickoff Meeting with the Energy Division at the CPUC’s offices in San Francisco, CA. We expect the meeting will be attended in person by Matthew DeCoursey and Drew Cayton from FTI and Tim Sexton from GSC; other Project Team members may also participate in person or electronically. We will also make electronic access available to the CPUC to distribute to other Energy Division staff or additional stakeholders who cannot participate in person. At the Kickoff Meeting, we will provide a detailed Gantt chart detailing the project schedule with milestones and deliverables, as indicated in the RFP.

Additionally, the Kickoff Meeting will be the forum to discuss revisions to this Scope of Work, if necessary, to specify protocols for the secure sharing of information, exchange detailed contact information for team members, and to identify the manner in which the Project Team will update Energy Division staff. As per the RFP, we will provide updates to the project schedule in the form of revised Gantt charts delivered to Energy Division staff; additionally, we propose that we schedule bi-weekly conference calls on the same schedule pursuant. The calls can be used to update Energy Division staff and, based on the CPUC’s preference, other stakeholders who the Energy Division may determine would be worthwhile to have in attendance.

Finally, prior to the Kickoff Meeting, the Project Team will forward to the Energy Division a Data Request (“DR”), the only such formal request we currently envision during the course of the assignment. We plan to rely heavily on results of the studies required by Senate Bill 380, including the Phase 2 results currently in process (collectively the “SB 380 Study Data”); data from the 2030 Integrated Resource Plan (“IRP”); and data from the additional sources listed in the RFP; particularly with regard to peak day demand for core and non-core gas customers and the expected configuration

of the pipeline network in California, as well as the capacities of the pipelines that serve the state.<sup>3,4</sup> As a guiding principle, it is our preference to use publicly-available information validated by stakeholders as the basis for the modeling we will conduct for this assignment, and these datasets provide the best source of that information. Our data request will include a spreadsheet for population with clear references to specific analytical inputs and outputs identified in the Phase 2 results, the IRP, and related documents. Providing the DR in advance will facilitate the discussion of any questions or concerns regarding its content at the kickoff meeting.

*Timeline and Deliverables:* We will issue the DR within one week of our retention. The Kickoff Meeting will be held at a mutually convenient time within two weeks. Aside from the DR, the only deliverable currently associated with Task 1 is the Gantt chart discussed above. Other deliverables such as contact lists, revisions to the schedule or approach described herein, etc., may be requested by the Energy Division at the Kickoff Meeting.

**Workstream 1: How can the services presently provided by the Aliso Canyon field be met if the field were to be eliminated by the two planning years of 2027 and 2045?**

*Summary:* To address this question, the Project Team will develop models that will allow for a detailed understanding of the operation of the gas and electric systems, and their interactions, and will, in collaboration with the Energy Division and with input from other stakeholders, develop several packages of infrastructure investments California could make that would facilitate a more rapid retirement of Aliso Canyon. Once finalized, those investment options will be analyzed in Workstream #2. .

#### **Task 2. Baseline Scenario: Simulation of Markets Without Aliso Canyon**

In Task 2, the Project Team will develop annual peak day evaluations of California’s gas and electric markets in order to determine whether Aliso Canyon can be removed from service by either of the two planning years of 2027 or 2045 under current Business-As-Usual (“BAU”) conditions. Further, in the event that the Project Team determines that Aliso Canyon cannot be removed from service in 2027 but can be removed from service in 2045 under BAU conditions, then the team will also analyze the timeframe between the years 2027 and 2045 to determine the first crossover year during which Aliso Canyon can be removed from service under BAU conditions.

For purposes of this analysis, we define the BAU conditions as the currently expected outlook for the California power and gas markets with regard to demand forecasts, the addition and retirement of generation and transportation infrastructure, renewables and DR/EE penetration, and other market determinants that will persist absent a policy intervention to address the Aliso Canyon retirement. As such, we intend to rely heavily on the SB 380 Study Data, the IRP data, and the related datasets included in the DR we will issue as part of Task 1.

Specifically, in Task 2 the Project Team will evaluate the capacities of each of the key gas pipelines of relevance to the California market. Our preferred method will be to use the Phase 2 results and other available public information. To

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<sup>3</sup> Core gas customers are those served by the LDCs while non-core customers include direct-connect industrials and gas-fired electric generators. In the event of a gas shortage, non-core customers will be curtailed first.

<sup>4</sup> It is our expectation that the data provided will include unit level peak-day gas demand for each gas-fired generator in the study area. If it does not, we can develop our own estimate using the Power Market Model; however, doing so could impact the timelines and budgets described herein.



the extent additional capacity analyses are required, the Project Team will develop and run hydraulic analyses of these pipelines using the Gas Delivery Model. A review of the pipeline topology in and around California indicates that there are at least ten pipeline systems of relevance. Table 3, below, lists systems that could be evaluated in support of the study. They include intrastate systems such as the SoCal Gas and San Diego Gas & Electric (“SDG&E”) systems as well interstate systems that transport natural gas supply from producing regions throughout the U.S. and Canada to California markets.

**Table 3. Natural Gas Pipelines Serving California**

| <b>Pipeline</b>             | <b>Parent Company/Owner</b> |
|-----------------------------|-----------------------------|
| <b>Interstate Systems</b>   |                             |
| El Paso                     | Kinder Morgan               |
| Gas Transmission NW         | TransCanada                 |
| Kern River                  | Berkshire Hathaway          |
| Mojave Pipeline             | Kinder Morgan               |
| Questar Southern Trails     | Dominion                    |
| Transwestern                | Energy Transfer             |
| North Baja                  | TransCanada                 |
| <b>Intrastate Systems</b>   |                             |
| California Gas Transmission | PG&E                        |
| SDG&E PL                    | Sempra                      |
| SoCal                       | Sempra                      |

Once the key pipelines to be analyzed are identified, the Project Team will review Phase 2 results and public data to assess capacities of each of these systems available to support California markets. To the extent available data is insufficient, the Project Team will develop hydraulic models of any pipeline system deemed necessary to support execution of the remainder of the study. For purposes of Task 2, that means evaluation of infrastructure capacity to deliver natural gas supply to California markets under BAU conditions for the years 2027 and 2045 to evaluate the shortfall, if any, during each of these planning years, that results from the cessation of operations at Aliso Canyon. The Project Team will also determine the first year in which existing infrastructure, absent Aliso Canyon would be sufficient to support demand requirements under BAU conditions (the “Aliso BAU Removal Date”).<sup>5</sup> We will seek guidance from Energy Division staff as to whether the Aliso BAU Removal Date should be based on the peak day or extreme peak day, a decision that will not need to be made until after the results of Task 2 are available for review.

The primary output from Task 2 is the identification of gas-fired generators which will not be able to receive gas on either the peak day or extreme peak day of a modeled year once operations at Aliso Canyon are terminated. Using the

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<sup>5</sup> The Energy Division’s view on the value of analyses covering the period between 2027 and 2045 is a likely topic of discussion at the Kickoff meeting. If directed to do so in those discussions, we can refine this Scope of Work accordingly.

Gas Delivery Model will allow us to identify specific, individual units, which will, in turn, provide the basis for developing options for investments in demand side measures, renewables, storage, or additional gas infrastructure in Task 3.

We note that we envision the completion of Tasks 2 and 3 before we undertake Task 4, which includes a detailed modeling inputs report, as described below. Based on our understanding of the RFP, this approach is preferable since, in our opinion, the inputs to the modeling to be undertaken in Task 2 are reasonably well bounded such that significant public input and comment on the structure of the models or their inputs will not be necessary; we will, of course, seek input from the Energy Division throughout Task 2. Moreover, we expect that the determination of the Aliso BAU Removal Date and the development of a deeper understanding of the viability of termination Aliso Canyon by the 2027 planning year at this point, before Tasks 3 and 4 are undertaken, will support a much more robust discussion with stakeholders during Task 4, with the focus appropriately placed on the identification and analysis of solutions, rather than on the analysis of timelines to reliability issues. While the Project Team thinks this makes sense, we also recognize that this approach is one of many and can, upon the Energy Division's request, re-order Tasks 2, 3, and 4 such that Task 4 is complete before any modeling work is undertaken. Doing so will not affect the budgets or overall project completion timelines described in this section of our proposal.

*Timeline and Deliverables:* Task 2 will require approximately ten weeks to complete, including compilation of the SB 380 Study Data and associated datasets. Our first deliverable will be a brief memorandum identifying the key pipelines that serve California that we will model. At the completion of Task 2, we will distribute the *Capacity evaluation and/or Hydraulic Modeling Memorandum*, describing in detail our approach and the results by which we determined the Aliso BAU Removal Date.

### Task 3. Alternative Scenarios Formation

In Task 3, the Project Team will identify potential solutions that can be implemented prior to the planning years of 2027 and 2045 that will enable retirement of Aliso Canyon while maintaining the security of the California electric system. Specifically, based on the insights developed using our Gas Delivery Model, we will specify portfolios of investments in new assets that can replace the generation from the curtailed units we identified in Task 2, flow additional gas to generators in the region, or both. Some of the technologies we will consider include, but are not necessarily limited to,

- Expansion of DR/EE installations beyond those that we expect to persist under BAU conditions;
- Expansion of the system of gas pipelines serving California, including the development of new pipelines or the expansion of capacities on existing systems,
- Replacement of gas-fired generation with wind and solar resources;<sup>6</sup> as well as,

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<sup>6</sup> Based on the descriptions in the RFP, we assume that neither increased reliance on coal- or oil-fired generation, either within California or imported by wire, nor the development of new nuclear generation, would be acceptable solutions, regardless of the timing of the Aliso BAU Removal Date.

- Expansion of electric battery storage, either at the utility scale or behind-the meter.<sup>7</sup>

For purposes of Task 3, we assume that the profile of electric demand from customers would remain fixed before adjustments for DR/EE; in other words, we would not, for example, attribute a reduction in peak demand or overall consumption to some postulated change in rate design.

Presently, we propose to develop a set of five scenarios for each of the two planning years of 2027 and 2045 that would have the technical capability of alleviating reliability concerns that arise at these planning dates, which we will codify in the *Preliminary Portfolios Memorandum*, which will be distributed to the Energy Division for review within two weeks of the start of Task 3. Therein, for each scenario, we will explain our rationale for selection the portfolio of solutions that comprises it, develop benchmark level facility cost estimates associated with each infrastructure solution, specify each solution (size, timing, cost, etc.), and support our determination that there exists sufficient lead time to construct and integrate the identified infrastructure. Most reporting regarding the scenarios will be undertaken in Task 4; however, it is our preference to provide Energy Division staff a preview of our findings before they are made public in Task 4. If requested to do so, we can combine Task 3 and Task 4.

#### Task 4. Assumptions, Scenarios, and Modeling/Analysis Plan

Following completion of Task 3, we will issue in draft form an Assumptions, Scenarios, and Modeling/Analysis Plan (the “Modeling Plan”), which will describe the methods and inputs we utilize beginning in Workstream 2 for the remainder of this assignment, for review by the Energy Division and also participate in a public workshop in Los Angeles, CA, the feedback from which will be used to finalize the Plan and re-distribute. Our approach to Task 4 will be consistent with pages 6-7 of the RFP.

*Timeline and Deliverables:* We expect to issue the draft Modeling Plan within two weeks of the completion of Task 3. The subsequent workshop shortly thereafter in consultation with the Energy Division and other stakeholders.

**Workstream 2: What is the feasibility of each proposed plan, technology, or mix of resources identified including the estimated time needed for construction or implementation?**

*Summary:* In Workstream 2, we will evaluate the universe of options to invest in infrastructure to support an accelerated retirement of Aliso Canyon. The Project Team will deploy our economic modeling suite as well as proprietary financial modeling tools to estimate the costs and benefits, as well as the emissions impacts, of each potential investment option. Using these results, we will identify one or more optimal investment options and memorialize our recommendations in a report suitable for publication.

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<sup>7</sup> For purposes of this proposal we assume that non-battery forms of energy storage will not be included in this analysis; however, we can readily incorporate energy storage alternatives such as demand location sited LNG peak shaving facilities, pumped storage or developmental technologies if directed to do so by the CPUC.

## Task 5. Modeling and Evaluation of Alternatives

In Task 5, we will verify the technical feasibility of each scenario identified in the *Final Portfolios Memorandum* and validate the economic impacts to California customers. To do so, we will run the entire modeling suite for each scenario. Specifically, the approach to the modeling for each scenario is comprised of seven steps:

*First*, we will run the Gas Market Model to determine delivered gas prices to California under postulated conditions. The trajectory of gas prices embedded in forward curves and/or BAU market sentiment may change significantly with the development of new renewables or DR/EE (either of which will reduce the demand for gas in California) the creation of new pipeline infrastructure, or both. Running the Gas Market Model will allow us to develop highly granular gas price forecasts applicable to each specific scenario.

*Second*, we will input the scenario-specific gas price forecast into the Power Market Model. Along with the other inputs provided in the SB 380 Data, the Phase 2 data, and the related datasets – electric demand, plant capacities and heat rates, etc. – these data will allow us to simulate the operation of the California electric market, including unit-level dispatch, and to forecast electric prices on an hourly basis.<sup>8</sup>

*Third*, we will iterate simulations between the Gas Market Model and the Power Market Model. Doing so is an important but often overlooked step to ensure convergence between the two models. Both the Gas Market Model and the Power Market Model has demand elasticity embedded in their pricing functions. That is to say that, for example, under high price conditions, demand for either power or gas will be less, and vice versa. Since the Gas Market Model requires demand for gas from electric generation as an input to its price formation mechanism, and the Power Market Model's consumption of gas is a function, in part, of the price of gas, it is necessary to run each in series, with the output of one model serving as an input to the other, for multiple iterations until convergence is reached and the demand outputs from both models are generally consistent. When convergence is achieved, the market simulations for the given scenario will be completed.

*Fourth*, we will run the Gas Delivery Model to confirm that the chosen solution provides for enough gas deliverability to the remaining thermal fleet to ensure the security of the California grid.

*Fifth*, we will develop an accounting of the total energy production cost for each simulation. This is the cost to serve all electric loads in California at prices determined by the Power Market Model, plus the cost to serve all core gas demands in the state at prices determined by the Gas Market Model.

*Sixth*, we will develop an accounting of the costs to build the new infrastructure identified in each scenario. We note that the RFP and the supplemental information published by the CPUC on February 19, 2020 focus on the wholesale market costs and/or rate impacts that will accrue to customers; however, it is our opinion that exclusion of the fixed costs for the infrastructure embedded in each scenario would be a significant omission. In short, each of the scenarios represents an investment that will be made on behalf of ratepayers, the costs of which should be considered in any

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<sup>8</sup> One potential input to Task 4 that is not mentioned in the RFP is a cost of carbon, which the Project Team could embed into the Power Market Model if directed to do so. Applying a carbon tax would tend to favor renewable-heavy solutions over alternatives that ultimately rely extensively on thermal generation, such as, for example, the development of new pipeline infrastructure.



cost-benefit analysis. To do so, the Project Team will calculate the annual, levelized cost of each set of infrastructure additions that the five scenarios comprise using publicly available cost indices, financial data for the California EDCs and LDCs (which will be used to estimate the Weighted Average Cost of Capital for investments in California energy infrastructure), and a basic and transparent financial model that will generate an estimate of the annual cost of each investment.<sup>9</sup>

*Seventh*, we will develop an accounting of the total carbon emissions from the electric sector based on the results of the Power Market Model. Note that we do not intend to measure emissions from LDC customers' consumption of natural gas.<sup>10</sup>

For each scenario, we currently plan to simulate the market for several years running up to the planning year being evaluated. It may be preferable to install some, many, or all of the identified solutions sooner than that year, in which case the timing of our simulations could be affected. We plan to discuss the timelines for the execution of the modeling suite with Energy Division staff on an ongoing basis beginning with the Kickoff Meeting and with stakeholders as part of Task 4.

*Timeline and Deliverables:* Upon completion of the analyses, we will distribute a draft *Modeling Results Memorandum*, which will describe in detail the economic, financial, and environmental results of each simulation. That document will also identify the investment option we determine to be most beneficial to ratepayers. We expect that task 5 will require ten weeks to complete.

#### Task 6. Electric Reliability Analysis

Following the completion of the Task 5 modeling, we will validate that our preferred solution(s) has maintained the reliability of the electric system. We do not expect to conduct separate reliability modeling for Task 6. Instead, we will provide commentary on the nature of the reliability issue that we identified in Task 2 and the manner in which reliability issues have been resolved. Specifically, we will compare operational outcomes associated with the BAU case (generation, pipeline flows, etc.), identify which system components contributed to the reliability violation and how, and explain how operations and system fundamentals (reserve margins, etc.) are improved when new infrastructure is installed. All analyses in Task 6 will be reported on a non-technical basis for consumption by the public and non-expert policymakers.

*Timeline and Deliverables:* We will issue the *Reliability Analysis Memorandum* within two weeks of the completion of Task 6.

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<sup>9</sup> We recognize that, in most cases, the EDCs will not be the direct developers of new infrastructure in California; however, we expect that most or all of that infrastructure will be supported via a long-term EDC contract. We have therefore chosen to use EDC WACCs for purposes of financial analysis. If preferable, this input can be adjusted with little to no impact on the budgets and timelines described in this document.

<sup>10</sup> In the long-run, core customers' consumption of gas is likely elastic to some degree and will decline in response to high prices, and vice versa. Measuring this effect, however, is beyond the scope of this analysis. Moreover, we do not believe that influencing LDC customers' gas consumption behavior should be a primary determinant of the Commission's decision-making regarding options to alleviate reliability issues that arise from the Aliso Canyon failure. We have therefore excluded this variable from our analysis.

## Task 7. Regulatory Constraints Analysis

It is our expectation that following the completion of Tasks 5 and 6 we will have identified our preferred option to enable replacement of Aliso Canyon in the planning years of either 2027 or 2045 and, likely, at least one additional viable option as well. The Project Team, working in conjunction with Energy Division staff, will determine whether there exist any regulatory constraints that would preclude the required investments under the preferred options. In other words, we will analyze whether regulations and incentives currently in place are compatible with the investments we expect will most likely benefit customers. For example, if we determined that major investments in DR/EE were part of an optimal package of measures that would benefit ratepayers, restrictions on utility DR/EE programs that could limit their investment would represent a regulatory constraint. Likewise, if our analysis indicated that the region should invest in new gas pipelines, then statutes precluding the California EDCs from executing long-term transportation agreements that would export such expansions would fall under the same category.<sup>11</sup> The precise parameters of the regulatory analysis will not be clear until after the completion of Tasks 5 and 6.

*Timeline and Deliverables:* We will issue the *Regulatory Constraints Memorandum* within three weeks of the completion of Task 6.

## Task 8. Reporting

In Task 8, we will summarize our findings in a draft report for comment and feedback from the Energy Division. It is our intention that each of the deliverables described above will effectively comprise a chapter of the final report; as such, the time required to develop the final report will be reasonably limited. Our final report will include a full summary of all methods, assumptions, findings, and recommendations.

Within two weeks of our receipt of the Energy Division's comments, we will schedule a public workshop in Los Angeles, CA, where we will present the draft final report, as amended. The report will be finalized within four weeks of the completion of the workshop.

*Timeline and Deliverables:* We will provide the CPUC with a draft of the final report within three weeks of the completion of Task 7. Assuming that we receive comments in three weeks, we will hold the public workshop approximately eight weeks after the completion of Task 7 and will finalize the report within four weeks following the workshop, for a total time elapsed of twelve weeks for Task 8.

## Schedule

Below, we summarize our schedule for the eight tasks described above, along with preliminary target dates for their completion. We note that the schedule shown below calls for completion of the project well before the final deadlines indicated in the RFP; that document requires delivery of the final report on or before May 31, 2021, our schedule calls for delivery of report nearly three months earlier. This provides the Project Team with the considerable advantage of

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<sup>11</sup> The issue of EDC support for new pipeline development became prominent in New England a few years ago. The state regulator approved the EDCs' execution of pipeline supply agreements that would serve to anchor system expansion, however, the appellate court of Massachusetts, then other states, determined that doing so was unconstitutional, the contracts were voided, and the pipeline expansion plans were terminated.

being able to adjust the schedule as needed, should circumstances arise, without jeopardizing overall deadlines for completion. This project schedule is provided for discussion purposes only and will be finalized at the Kickoff Meeting.

**Table 4. Indicative Project Schedule**

| <b>Task</b> | <b>Milestone</b>   | <b>Time Elapsed</b> | <b>Target Completion</b> |
|-------------|--|---------------------|--------------------------|
| 1           | Kickoff Meeting  | 2 weeks             | April 22, 2020           |
| 2           | Baseline Scenario Analysis                               | 10 weeks            | June 29, 2020            |
| 3           | Alternative Scenarios                                    | 2 weeks             | July 13, 2020            |
| 4           | Draft Assumptions, Scenarios, and Modeling/Analysis Plan | 2 weeks             | July 27, 2020            |
| 4           | Public Workshop  | 2 weeks             | August 10, 2020          |
| 4           | Final Assumptions, Scenarios, and Modeling/Analysis Plan | 3 weeks             | August 31, 2020          |
| 5           | Financial and Economic Analysis                          | 10 weeks            | November 9, 2020         |
| 6           | Electric Reliability Analysis                            | 2 weeks             | November 23, 2020        |
| 7           | Regulatory Constraints Analysis                          | 3 weeks             | December 21, 2020        |
| 8           | Draft Final Report                                       | 3 weeks             | January 18, 2020         |
| 8           | Public Workshop  | 2 weeks             | February 1, 2020         |
| 8           | Final Report   | 4 weeks             | March 1, 2021            |

This schedule is predicated, in part, on our retention on or about April 15, 2020 as indicated at p. 23. of the RFP, and on the timely availability of the modeling inputs discussed above, some of which are being developed as part of the Phase 2 investigation. Nullification of either of those assumptions could require changes in the timelines shown in Table 4, though as we note above, there is a significant amount of time before our current expectation of the completion date and the May 31, 2021 target date for the draft report indicated at p 7 of the RFP.

## 8. Modeling Suite

The Project Team proposes the use of a number of cutting-edge models to conduct simulation analyses of market conditions. To conduct the work described in Section 7, we will run three models: WinFlow and WinTran, which we license from Gregg Engineering, Inc. (collectively the “Hydraulic Models”), PLEXOS, which we license from the Energy Exemplar, and GPCM, which was developed and is maintained by RBAC.<sup>12,13,14</sup>

Descriptions of each model, as well as the interactions between modeling tools, are described below.

### Gregg Engineering WinFlow/WinTran

The Project Team will utilize Gregg Engineering’s WinFlow and WinTran pipeline hydraulic modeling software as a platform to develop steady state and transient flow simulation models of the pipeline infrastructure in the WECC region. Gregg Engineering has been providing hydraulic pipeline simulation modeling software since 1986 and Gregg’s WinFlow and WinTran software are industry-standards in the US and around the world as a platform for modeling hydraulics of natural gas gathering, transmission and distribution pipeline networks.

#### WinFlow

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

- gas properties (gas composition, gas temperature, gas heating value, gas pressure, etc.);
- pipe properties (pipe diameter, pipeline length, pipeline roughness, compressor HP, etc.);
- operating conditions (ambient temperature, ground temperature, elevation, etc.);
- user defined pipeline equation (i.e., Weymouth, Panhandle, Colebrook, AGA, etc.); and
- receipt and delivery quantities.

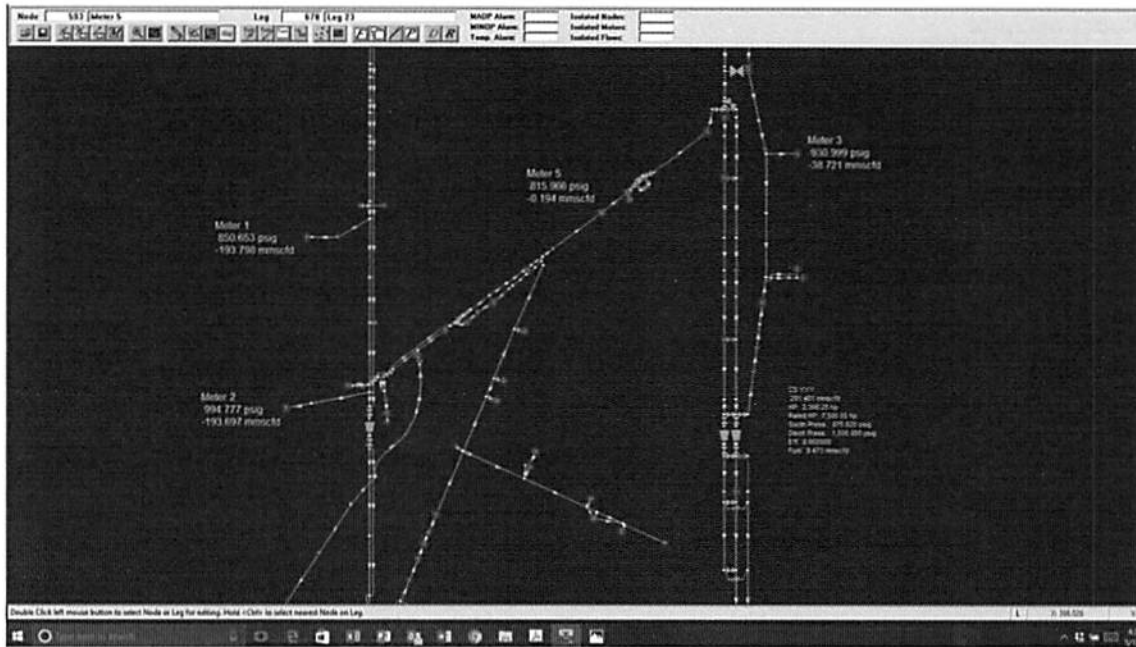
Once the data is input, the software provides a graphical interface and enables the user to visualize and simulate the operations of a pipeline system. The illustration below provides an illustrative example of the interface that would be seen by the user in developing a pipeline model.

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<sup>12</sup> <https://www.greggeng.com/>

<sup>13</sup> <https://rbac.com/gpcm-natural-gas-market-model/>

<sup>14</sup> <https://energyexemplar.com/solutions/plexos/>



Using the graphical interface coupled with the model parameters, the WinFlow software enables the user to evaluate the operating capacity of the pipeline system under different flowing conditions in a static or steady state environment.

### WinTran

In addition to the WinFlow software, the Project Team will utilize Gregg Engineering’s WinTran software to evaluate the operations of the pipeline systems under changing conditions. As deliveries to end users, particularly electric generators, are rarely made on a uniform static basis, the use of the WinTran software is critical to the evaluation of the capability of the pipeline infrastructure to meet varying demand requirements during a day.

As demand fluctuates during a day, the pipeline system will pack up (line pack and on-system pressures will increase) and compressor usage will decrease during off peak hours and will draft down (line pack and on-system pressures will decrease) and compressor usage will increase during peak delivery periods. As such, the WinTran model is used to evaluate changing conditions during a day.

Further, as part of the project, the Project Team will be evaluating contingency events that occur during a simulation such as compressor failures, pipeline breaks, load shedding, etc. The WinTran software will enable the Project team to simulate the impacts of contingency events in real time to evaluate the impact of such events.

WinFlow and WinTran are the industry-standard application for hydraulic analysis of flows in gas pipelines and are in widespread use by pipeline companies, LDCs system planners, and market regulators.

### PLEXOS

PLEXOS is an established power model used widely in the industry, including by the CAISO and CEC, to simulate the operations of power systems with a realistic and robust representation of generation and transmission. The results from PLEXOS’ simulation provide the least-cost, long-term system expansion plan, as well as the short-term (hourly)

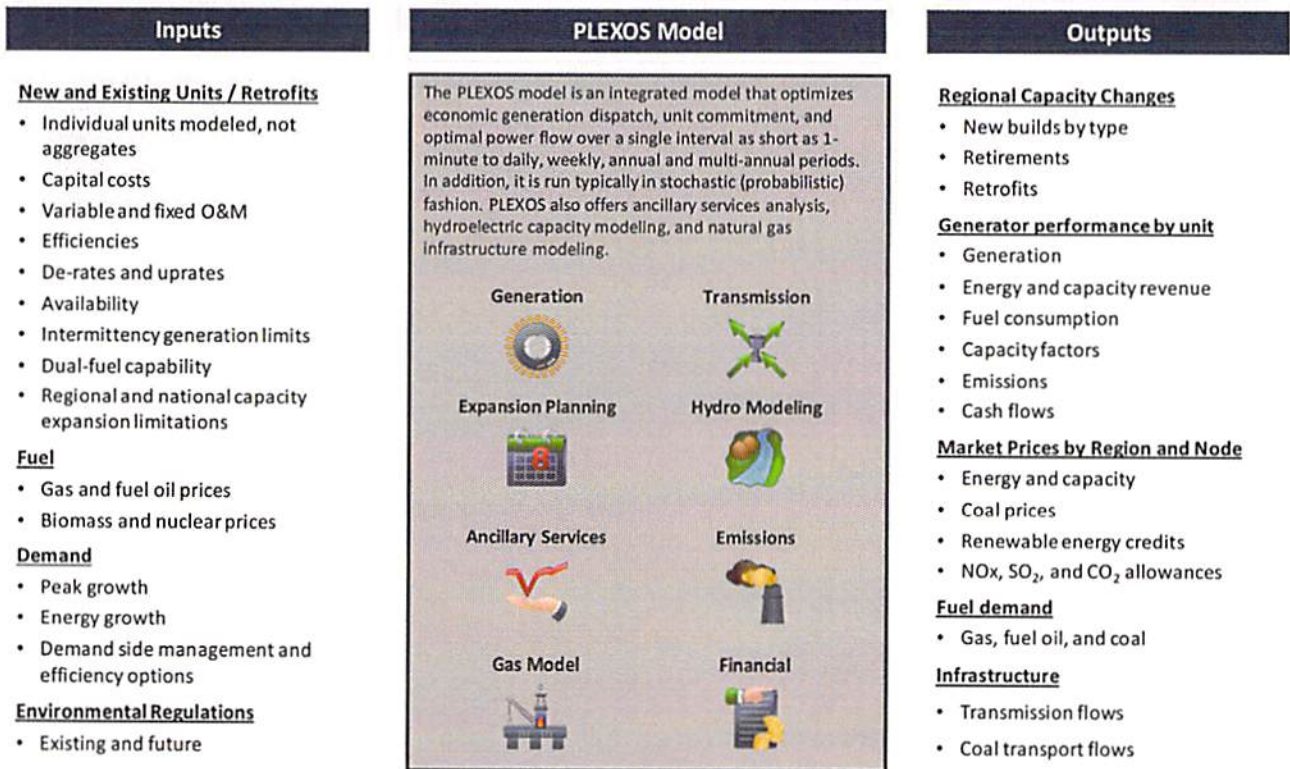


operation or dispatch of generation plants from thermal plants to hydro plants to batteries. PLEXOS has the flexibility to use simplified representations of the power system to enable the provision of timely and cost-effective answers to the problems at hand such as the representation of hourly loads as a number of monthly blocks that can be visualized as monthly load duration curves or the creation of meaningful zones within a larger power system to represent sub-markets with transmission constraints between the regions. The Team believes it is particularly well-suited for this engagement for several reasons.

First, creating and testing long-term supply plans to minimize costs subject to constraints will be a key part of the analysis and PLEXOS is well-suited to conducting such analyses. Example of the types of supply plans that might have to be examined include:

- The least cost mix of solar, wind, and battery storage that must be built (i.e., level and timing of each) on the system if total gas use has to held to a certain level by 2027
- The sensitivity of the least cost mix above to changes in cost and performance of each technology
- Total level of CO2 emissions under a given plan and how the plan might change with tighter CO2 constraints

**PLEXOS is well-suited to conduct long-term market analysis including forecasting regional electricity and capacity prices, generation, new builds, and retirements under various fuel, load, and policy scenarios.**



PLEXOS can be run in an hourly chronological mode, but it can also be configured to simplify the representation of load to a user-specified number of blocks per month (in a load duration curve) and dividing the system into user-defined zones, thereby allowing rapid and cost-effective testing of alternatives, while maintaining a correct representation of the system. Another feature of PLEXOS that makes it well suited for this engagement is its ability to mesh the use of a

simplified zonal/LDC representation with a deep look at select years using a chronological, hourly, model with a representation of the transmission topology. The team works extensively with one such model, ENELYTIX. Finally, PLEXOS provides ease of communication with California stakeholders because entities like the CAISO and CEC already use PLEXOS.

### GPCM<sup>15</sup>

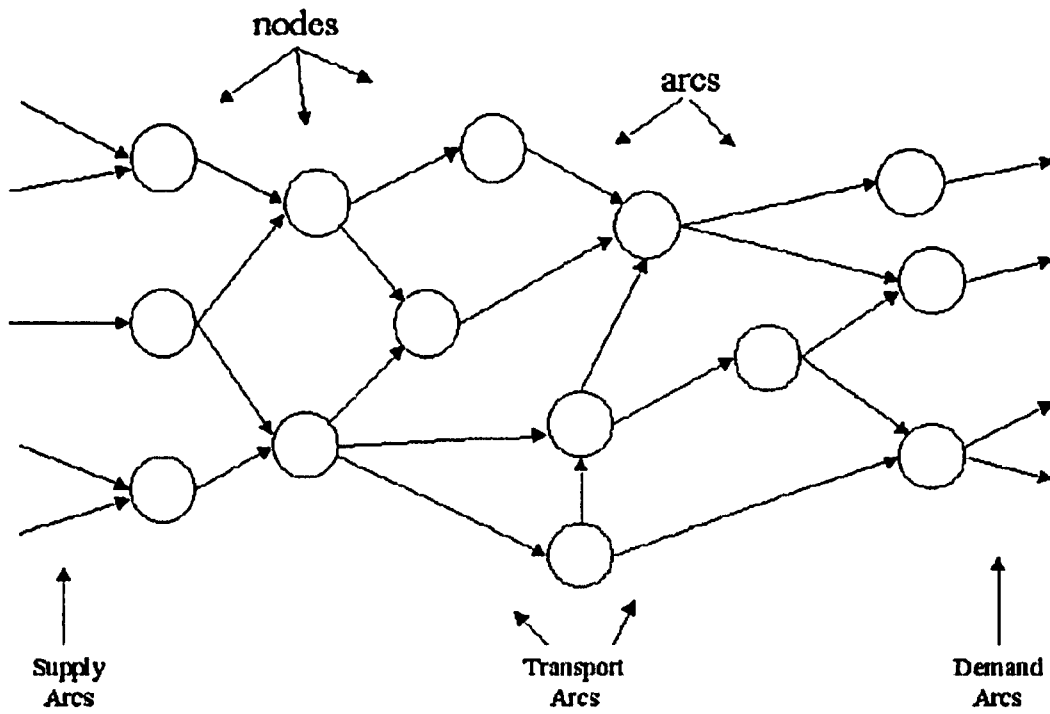
GPCM is a model of an integrated natural gas market such as the one in North America. It is a network model consisting of points where natural gas is produced, bought, sold, stored, and consumed. These points are called “nodes” in a network model. It consists of paths through these various points representing the pipeline grid, which delivers gas from producing areas to consumers. Each point-to-point component of a path in a network model is called an “arc.” The questions that GPCM answers are: given a set of assumptions about supply in producing areas and demand in consuming areas, plus knowledge about the capacity and cost of transportation and storage in the grid, what set of prices at the nodes and flows on the arcs is consistent with a relatively free and competitive market for natural gas.

GPCM calculates these answers by using the basic principles of equilibrium economics. For the gas market, this means that supply and demand must be in balance. This balance must exist at every point in the market—that is, at every node in the model. A balance, or equilibrium, occurs when the price differential between any two points in the network balances with the cost of moving gas between those two points, and, therefore, there is no reason to increase or decrease the amount of gas flowing between the two points. At supply points, this would mean that there is no reason to increase (or decrease) production because the amount produced is equal to the amount demanded at that price. At demand points, there is also no reason to increase (or decrease) the amounts of gas demanded because supply and demand are in balance at the market price. GPCM uses a step-by-step, iterative method to compute this equilibrium solution. It starts with a trial “solution” which has no gas flowing in the network. From this beginning point, it scans through the various possible supplies, demands, and pathways from supply points to demand points, and finds the one which has the greatest price/cost differential. It then creates a new trial “solution,” moving the maximum amount it can from a low-cost producer along a low cost pathway to a consumer who is willing to pay a high price. At this early point in the solution process, prices are low at that supply point, high at the demand point, and at intermediate levels at the various transportation points used to move gas from the supply to the demand point.

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<sup>15</sup> This description of GPCM is reproduced with the author's permission from: Treyz, F., et al (2012) *The Macroeconomic Impacts of LNG Exports: Integrating the GPCM Gas Model with the PI+ Regional Model*. Presented at the 31st USAEE/IAEE North American Conference, Austin TX

## GPCM Network Model



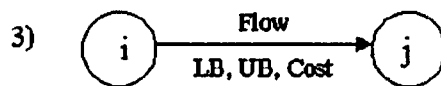
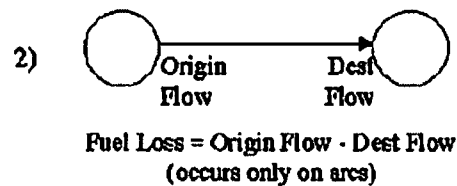
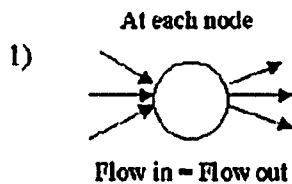
The algorithm then looks for another, similar situation where a profitable flow from producer to consumer can take place. Iteratively, GPCM must compute an implied price at points in the transportation network. As the capacity of each pathway fills, the price of transporting along that path increases, reflecting the operation of supply and demand for transportation. Since more gas is demanded at various supply points, higher cost producers can sell their gas, and the price at these points goes up. The consumers willing to pay higher prices find contentment to their preferences, and the market tries to yet satisfy those customers not willing to pay so much. From there, prices at the demand points come down.

GPCM continues to look for opportunities to move gas from suppliers to consumers that have an economic benefit associated with them. This is exactly analogous to the process that current gas traders and marketers use to make money for their firms. If they find a way to move gas from one market point to another at a cost less than the price differential between those points, they will do so. This process can also involve time. In other words, they might want to buy gas at a certain point during one period, store it, and then sell it at the same or a different price later. If the relative price between these two space-time points is greater than the cost, then the trader will try to make the deal. GPCM computes prices and flows over both space and time, including storage injections and withdrawals as well as production, pipeline transportation, and delivery to customers. Its algorithm uses the same "thought process" that traders and marketers use to conduct business in the competitive North American market for natural gas.



The GPCM algorithm will always converge to a solution where the price and flow variables are consistent with an economic equilibrium, per the mathematicians behind the model's functional structure. This means that all of the arbitrage opportunities discussed will clear, and the system will balance at every point and period of time. The model is consistent with industry and private behavior. The only instances where price differentials between two points will be different from the cost of transportation and/or storage will involve "congested" paths between those points where there is no more capacity left to sell. In those instances, GPCM would like to take advantage of the potential for additional economic benefit, but there is not enough physical capacity to do so. This is very important information, because the solution is actually an alert for locations where additional capacity might be needed in the present or future. The difference between the price differential and the cost is a measure of the economic value of additional capacity between those two points.

### GPCM Constraints – Rules for Market Clearing



3a) If  $LB < Flow < UB$  then  $P_j = P_i + Cost$

3b) If  $P_j > P_i + Cost$  then  $Flow = UB$

3c) If  $P_j < P_i + Cost$  then  $Flow = LB$   
where  $P_i$  = price at node  $i$ ,  $P_j$  = price at node  $j$

3d)  $Rent = P_j - (P_i + Cost)$

3e) If  $Rent > 0$ , then  $Rent$  = marginal value of increasing the  $UB$ .

3f) If  $Rent < 0$ , then  $Rent$  = marginal cost of increasing the  $LB$ .

The equilibrium solution defined by GPCM based on the constraints described above provides a forecast of delivered prices, indicated by location through the North American pipeline network, as well as forecasts of gas produced (supply), gas consumed (demand), and flows across pipelines differentiated by segment.