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FROM: **FTI/GSC Project Team**

DATE: **March 15, 2021**

RE: **Workstream #2 Approach: Portfolios Framework and Research Methods**

This memorandum describes the analytic framework that FTI Consulting ("FTI") and Gas Supply Consulting ("GSC," collectively the "Project Team") presently plan to utilize for the next phase of our analysis of options for replacing the Aliso Canyon gas storage facility, which the Project Team is undertaking in our role as the California Public Utilities Commission's ("CPUC's" or the "Commission's") expert advisor for Phase 3 of the ongoing investigation into options to facilitate Aliso Canyon's retirement.[1] The framework reflects feedback and input received from stakeholders, including during and after the public workshop held as part of the proceeding on November 17, 2020 (the "November Workshop"); ongoing discussions and guidance from the CPUC; and the Project Team's ongoing research and analysis.

The next phase of our assignment, which has been described in the November Workshop and elsewhere as Workstream #2, represents an important change in focus. Workstream #2 builds on results developed during Workstream #1, the objective of which was to analyze California's gas and electric systems via simulation and to understand how their operation could change if Aliso Canyon is retired. Based on the results that were developed for that purpose, the potential reliability impacts attributable to the decision to retire Aliso Canyon were estimated. Specifically, the Project Team estimated the amount of Electric Generation ("EG") that would be needed during high-demand conditions but could not be served if Aliso Canyon is shut down and no other changes to the system are made, the ("EG Shortfall").

For Workstream #2, we will define portfolios of infrastructure investments that would address the EG Shortfall by increasing the amount of gas available in system, increasing the amount of non-thermal generation available, or by reducing demand for gas and/or electricity, and then analyze each based on the net benefits they provide, inclusive of changes in energy prices, the cost to build new infrastructure, and other factors. Details regarding the planned approach are provided in the remainder of this document.

After Workstream #2, the Project Team will undertake an analysis of "regulatory gaps," review of market rules, and other concluding analysis. Since the focus of this memorandum is the

[1] Proceeding I.17-02-002 before the Commission.

analytical framework and assumptions that will be utilized during Workstream #2, these other tasks are intentionally omitted from the discussion that follows.

WORKSTREAM #2 FRAMEWORK

Summarized at a high level, Workstream #2 will be comprised of three steps. *First*, the Project Team will define a number of infrastructure investments that could be made that would facilitate Aliso Canyon's retirement. Investments are made in portfolios that may contain investments in more than one individual pieces of infrastructure. *Second*, the team will estimate the market change attributable to each investment, which primarily rise from the changes (reduction) to local electric and gas prices that result from the new assets being added to the system. *Third*, net benefits of each portfolio, including the market change and the cost of building new infrastructure, will be calculated using a financial model developed for that purpose. Each step is described below.

Investment Portfolios

Four investment portfolios will be specified at the outset of Workstream #2. Two comprise new gas-side investments and two are made up of electric infrastructure. As discussed during the November Workshop, a fifth portfolio will remain undefined until we have developed preliminary results of the other four, which we will use to inform our decisions for the last portfolio.

Each of the portfolios are sized to offset the impact of the loss of gas deliverability attributable to Aliso Canyon's retirement. During Workstream #1 we found that if Aliso Canyon were removed without replacement, a gas deliverability shortage will be created because the system will be unable to deliver enough gas to simultaneously serve core, non-core electric generation (EG), and non-core, non-EG demand during peak conditions. The total shortfall, which the Project Team estimated for winter peak days in each of 2027 and 2035, is equal to the difference between total gas demand and the amount of gas the system can deliver without Aliso Canyon, with all other assumptions held constant.

Results of the Workstream #1 analysis indicate that during the critical hour in 2027, the hour in which the largest gas delivery shortfall was observed, the shortfall is expected to be 32.6 million cubic feet (MMcf) and that the required capacity increment to address the shortfall is 434 million cubic feet per day (MMcf/d).[2] Because gas demand is expected to decline over time, the critical hour shortfall in 2035 is less. Results are summarized in Table 1.

[2] The daily capacity requirement is based on the hydraulic analyses the Project Team conducted and accounts for the availability of line pack, alternative storage sources, and other factors to determine the amount of gas deliverability that would be needed to serve all demands for every hour of the peak day. For this reason, the incremental deliverability requirement is less than twenty-four times the critical hour shortfall. See the information presented by the Project Team during the November Workshop (the "November Workshop Presentation") at p. 47 and p. 60, available at https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2020/FTI%20Research%20Presentation.pdf

Table 1. Calculation of Required Offset to Gas Deliverability Shortfall

	Critical Hour Shortfall	Required Offset
2027	32.6 MMcf	434 MMcf/d
2035	24.2 MMcf	318 MMcf/d

Two of the investment portfolios are designed to address the shortfall by changing the balance between *gas* supply and demand, either by increasing the amount of gas available in California or by decreasing demand. Each are described below:

Portfolio #1. Gas Transmission Portfolio

The gas transmission portfolio consists of investments in new pipeline infrastructure that will increase deliverability in sufficient quantities to offset Aliso Canyon's removal. The Project Team expects that increasing the capacity of the Southern California Gas Company's (SCG) Northern Zone will likely be economical. As such, we will analyze the impact of restoring the Northern Zone to its nominal capacity of 1,590 MMcf/d.[3]

The Project Team is also evaluating whether existing bottlenecks elsewhere on the SCG system will need to be addressed as part of these improvements. For example, we are aware of constraints between the Honor Rancho storage facility and the Los Angeles Basin that limits access to gas stored there under certain circumstances.

We are aware of the extensive discussions regarding Receipt Point Utilization ("RPU") assumptions used during Phase 2 of the investigations, and in other settings, and that the RPU will have a significant impact on the size and composition of this portfolio. The Project Team will present our RPU recommendations, which apply only to this scenario, at the stakeholder session scheduled for March 30, 2021 and will not finalize the approach until feedback on that recommendation has been received.

Portfolio #2. Gas Demand Reduction Portfolio

The demand-side gas portfolio is comprised of an increase in demand response (DR) and energy efficiency (EE) penetration as well as building electrification initiatives. The Project Team is developing an outlook on the shares that each of those measure types will contribute to the total offset, which we will present at the next workshop.

Datasets the Project Team are reviewing as we formulate this portfolio include analyses required by and related to implementation of Assembly Bill 3232 and Senate Bill 350,

[3] For a discussion of the maintenance issues that currently limit the Northern Zone's delivery capability, see https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2018/08_16/.

reporting by the California utilities' demand-side programs, and related public information.

The other two portfolios that are defined at the outset of Workstream #2 focus on the electric system. One increases the amount of non-thermal generation available to meet system demands while the second increases electric transmission into the region. The electric portfolios are each sized to meet the EG Shortfall, which was estimated during Workstream #1 based on the amount of gas-fired generation that would be required to maintain reliability but that would not be able to be served without Aliso Canyon or its replacement. The EG Shortfall for each of 2027 and 2035 is shown below.[4,5]

Table 2. Critical Hour EG Shortfall

	Unserved Generation
2027	4,768 MW
2035	2,866 MW

The composition of each of the two electric portfolios is described below.

Portfolio #3. IRP Expansion

As described during the November Workshop, our baseline modeling is based on the current Integrated Resource Plan ("IRP"), which includes an outlook for the mix of new wind, battery capacity, and DR to be built by 2027, each of which are expressed on a nameplate basis:[6,7]

Table 3. IRP New Build Assumptions for 2027

	Nameplate MW	Share
Wind	152	32%
Battery storage	312	67%
DR	4	1%
Total	467	100%

[4] These values vary slightly from the results presented during the November Workshop. The difference arises from a change in the manner in which the expected gas shortfall was converted to an estimate of unserved EG which increased the impact by 13% in 2027 and 10% in 2035. The Project Team will explain this change in detail at the next public workshop.

[5] As discussed later in this memorandum, the electric transmission portfolio is analyzed only for 2035.

[6] Nameplate capacity, sometimes called Installed Capacity (or "ICAP") refers to the physical capacity of a generating resource to provide power in MW based on engineering performance tests. A resource's firm capacity, which is adjusted for its peak Capacity Factor ("CF"), sometimes called its Unforced Capacity ("UCAP"), accounts for intermittency in order to estimate the resource's contribution to meeting peak demand for planning purposes.

[7] The IRP also provides the basis for the analyses conducted by CPUC and its advisors during Phase 2 of the ongoing investigation.

The capacity added in this portfolio to address the shortfall from removing Aliso Canyon is incremental to these additions and is assumed to be added in the same ratios. Those increments, which require new builds considerably greater than those called for in the IRP, are shown below. Note that the total firm capacities added are equal to the MW shortfall shown in Table 2.

Table 4. Incremental Builds to Address Shortfall

	2027			2035		
	Nameplate *(MW)*	**CF**	**Firm Capacity** *(MW)*	**Nameplate** *(MW)*	**CF**	**Firm Capacity** *(MW)*
Wind	2,010	29%	583	1,160	39%	415
Battery	4,134	100%	4,134	2,385	100%	2,385
DR	52	100%	52	30	100%	30
Total			4,768			2,866

The total additions shown in Table 4 will be achieved by increasing the size of the resources assumed in the IRP on a *pro rata* basis.

Portfolio #4. Electric Transmission

The fourth investment portfolio is designed to resolve the EG Shortfall by replacing lost generation with incremental transmission capacity. In order to better reflect current commercial and operational preferences and needs, we have chosen to base the transmission portfolio on a project currently in an advanced stage of development, the Delaney Colorado River Transmission Ten West Link Project (the "Ten West Project"), which we presently expect to receive its Certificate of Public Convenience and Necessity from the Commission later in 2021.[8]

Specifically, we will assume that a transmission project of the same specifications of the Ten West Project, "scaled up" to meet the 2035 EG Shortfall, would be developed and put into service that year. Actual project data filed in conjunction with the Ten West Project will be used to estimate the cost and impacts of such a project. The electric transmission portfolio is analyzed only for 2027.

The fifth investment portfolio will be specified once preliminary analyses of the other portfolios is complete.

[8] See docket A-16-10-012, available at https://www.cpuc.ca.gov/environment/info/dudek/tenwest/index.htm.

Economic Analysis

The purpose of the economic analysis is to measure the impact on the energy market created by developing each of the five portfolios and to calculate the net benefits that arise from that change. To the extent that benefits do accrue, we expect a primary driver to be reductions in the wholesale price of energy that arise from the installation of new infrastructure. Net benefits can be positive or negative, depending on whether reductions in customers' energy costs realized when the new infrastructure is put in place, if any, are greater or less than the cost of building the new facilities. A second important benefit will be the displacement of carbon emissions, which we will value based on the carbon allowance prices utilized in the 2017 Integrated Energy Policy Report.[9,10]

Estimation of each of these benefits will be based on results extracted from an economic modeling suite we will use to build 20-year simulations of the electric and gas markets of California and surrounding regions. During the November Workshop we summarized the PLEXOS model, which we used to estimate peak-day gas burns. The modeling principles applicable to a 20-year forecast are largely the same, with the key difference being the use of long-dated modeling inputs.

To analyze gas market impacts, the Project Team will utilize GPCM, which we license from RBAC, Inc.[11] GPCM is the industry-standard tool for forecasting economic outcomes in the natural gas market. The model allows us to develop highly granular forecasts of delivered gas prices based on assumptions for gas production and demand, pipeline and storage infrastructure, costs of transportation, and other factors.

We will first develop a Business as Usual ("BAU") forecast in each of PLEXOS and GPCM and then execute simulations that enact each of the investment portfolios while holding all other inputs constant. The difference in market prices, resulting costs to California ratepayers, and changes in emissions compared to the BAU forecast is the benefit attributable to each portfolio.

The economics of each investment portfolio will be separately analyzed beginning in 2027 and 2035, except the electric transmission portfolio, which will be analyzed only beginning in 2035. Simulations beginning in 2027 will be run for 20 years. We currently expect that simulations

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[9] http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-03/TN222145_20180116T123231_2017_IEPR_Revised_Carbon_Allowance_Price_Projections.xlsx.

[10] For reasons explained above, we expect that that the frequency of OFOs imposed on the system will decline prior to 2027, regardless of decisions made about Aliso Canyon's continuing operation, due to declining gas demand. If subsequent analyses indicate that OFOs will persist in the future, it may be appropriate to analyze the degree to which the investment portfolios contribute to OFO reductions and the economic benefits that could result from doing so. We will update participants on this topic at the next workshop as part of our presentation on the system balancing issue.

[11] https://rbac.com/gpcm-natural-gas-market-model/.

beginning in 2035 will be executed for 10-15 years, with extrapolation of results to develop a 20-year outlook for each simulation.[12]

In each case, the Project Team will run multiple iterations between PLEXOS and GPCM to ensure convergence of gas demand profiles.[13]

Primary outputs from each simulation will include emissions generated as well as market prices for energy, which will serve as inputs to the financial analyses used to calculate the benefits associated with each investment.

Financial Analysis

Simulation results will be used to populate a financial analysis the Project Team will develop to estimate the "all-in" net benefits to California ratepayers that will convey in a single number the value of a given infrastructure portfolio to investors.

Generating those results will require, among other things, estimates of the total capital costs for each of the portfolios we analyze. To develop those estimates, we will rely entirely on publicly available data from California and other jurisdictions. Based on the reviews we have conducted to date, we expect to utilize the following sources of data, shown below in Table 5; additional data sources may also be incorporated.

[12] 20-year simulations beginning in 2035 are impractical because developing inputs that far in the future requires significant speculation. We have therefore developed this approach to balance the interests of robustness, transparency, and consistency.
[13] We also expect to re-run our hydraulic models to demonstrate that system needs are met when the new infrastructure associated with each portfolio is installed to replace Aliso Canyon.

Table 5. Anticipated Sources of Capital Cost Data

Portfolio	Data Sources
1. Gas transmission	Costs for restoring the delivery capability of the Northern Zone system will be based on data available in proceedings before the Commission. This data will be augmented with information from other filings before the Commission, before the Federal Energy Regulatory Commission ("FERC"), and, potentially before regulators in other states. We expect to additionally rely heavily on FERC data to estimate the costs of expanding deliverability in the Southern Zone, if necessary and the capacity of the SCG receipt points.
2. Demand-side gas	We will rely on the costs and achievement levels for EE and DR reported in filings made with the Commission and related reports stored at the California Energy Data and Report System ("CEDARS").[14] The objective will be to estimate marginal, unitized costs for generic incremental EE and DR savings, which will then be scaled to the level required by the offset, constrained by maximum implementation levels, changes in marginal costs at different implementation levels, and other factors. We expect that data on electrification costs and benefits will be based on studies in the public domain, including, but not limited to, studies recently published in 19-DECARB-01.
3. IRP expansion	We will utilize the cost data reported in the IRP datasets to estimate the capital cost of the technologies that comprise this portfolio. Where necessary, these data will be supplemented with data from other jurisdictions regarding the costs of battery, wind, and solar resources.
4. Electric transmission	Data filed with the Ten West Project applications before the Commission and in other jurisdictions. This data may be augmented with information from FERC filings made regarding this or other electric transmission expansion projects.

The Project Team will use the capital cost data to estimate the total capital outlay associated with each portfolio, after which we will undertake financial modeling to estimate the total net benefit associated with each portfolio.

The financial analysis will also require us to make assumptions regarding the ownership of each portfolio. At present, we expect that we will analyze the new infrastructure associated with the gas transmission portfolio, the demand-side gas portfolio, and the electric transmission portfolio under the assumption that those assets will be owned by the gas and electric utilities and that the resources brought online as part of the IRP expansion portfolio would be commercialized

[14] https://cedars.sound-data.com/.

under contract. This is an assumption the Project Team is continuing to analyze. We will present our recommendation at the next stakeholder workshop and, later, report on the impact of the ownership decisions we made.[15]

Specifically, the net benefit of a portfolio is equal to the difference between two values, each of which are expressed as a series of cash flows that vary year by year and which accrue to California ratepayers over the 20-year forecast period by which we will evaluate each infrastructure portfolio. The first cash flow is the series of economic benefits that will arise from building the new infrastructure defined in each portfolio, which arise from changes in wholesale gas and electric prices as well as the economic value of displaced CO_2 emissions. Each of these reduces the cost to serve load in California, compared to the BAU outlook, which in turn creates a benefit that changes year by year. A discount rate is applied to the benefits to capture uncertainties and the time value of money, which results in a total discount expressed on a Present Value ("PV") basis.

That benefit is offset by the second cash flow, which captures the cost of investing in and owning the new infrastructure. These costs include, but are not limited to, initial capital expenditures plus yearly financing payments, taxes and depreciation, and operating expenses. For utility-owned infrastructure, returns on equity at rates authorized by the Commission that would be recovered by customers would also be considered.

A PV of the costs for any portfolio is calculated in the same manner as for the benefits. Comparing the PV of the benefits to the PV of the costs yields the Net Present Value ("NPV") of the portfolio, a single value which can be used to directly compare the net benefits of each portfolio. Often, a cost-benefit ratio is also expressed, calculated as the ratio of the PV of benefits to the PV of costs.

For any given portfolio,

$$\text{NPV} = \text{PV of benefits} - \text{PV of costs}$$

$$\text{Cost benefit ratio} = \frac{\text{PV of benefits}}{\text{PV of costs}}$$

Investments that have a positive NPV can be said to have benefits greater than their costs while those with a negative NPV can be said to have costs greater than benefits.

[15] We intend to develop and maintain relatively simple, transparent financial models to conduct the analyses described in this section and to make those models available to stakeholders. Among the other benefits of doing so is that this approach will allow interested parties to quickly determine what impact, if any, assumptions like project ownership, other inputs, have on the final results.