**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Continue Electric Integrated Resource Planning and Related Procurement Processes.	Rulemaking 20-05-003 (Filed May 7, 2020)

**COMMENTS OF CALPINE CORPORATION
ON ADMINISTRATIVE LAW JUDGE'S E-MAIL RULING
ON NATURAL GAS ISSUES**

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Pursuant to the October 13, 2021 Administrative Law Judge's *E-Mail Ruling Inviting Comments on Natural Gas Issues* ("Ruling"), Calpine Corporation ("Calpine") respectfully submits the following comments on the final California Energy Commission ("CEC") *Midterm Reliability Analysis* dated September 2021,[1] the California Public Utilities Commission ("Commission") Staff Paper on *Considering Gas Capacity Upgrades to Address Reliability Risk in Integrated Resource Planning* dated October 2021 ("Staff Paper"),[2] and specific questions contained in the Ruling.

Calpine appreciates the thoughtful analysis in the Staff Paper, and agrees with its quantitative conclusions that investment in incremental gas capacity could reduce system costs and lower emissions while supporting mid-term reliability. In addition, the Staff Paper presents compelling qualitative arguments for near-term procurement of incremental gas capacity, including that: (a) continued reliance on gas capacity for reliability is consistent with the state's environmental goals because gas generation capacity factors continue to fall; (b) some of the

[1] *See* CEC Staff Report, *Midterm Reliability Analysis* (Sept. 2021), https://efiling.energy.ca.gov/GetDocument.aspx?tn=239881&DocumentContentId=73322.

[2] *See* CPUC, *Considering Gas Capacity Upgrades to Address Reliability Risk in Integrated Resource Planning* (Oct. 2021), https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2019-2020-irp-events-and-materials/cpuc-gas-upgrades-staff-paper-october-2021.pdf

existing gas capacity that integrated resource planning ("IRP") modeling has been assuming will continue to operate may retire (especially combined heat and power ("CHP") units); and (c) overreliance on batteries to meet reliability requirements is risky because batteries may not be built on the scale necessary to obviate the need for existing and incremental gas capacity and, even if they are built, they may not perform as expected.

The Staff Paper's analysis reinforces the Commission's finding in the Mid-Term Reliability ("MTR") Decision that "allowing some incremental and efficient natural gas generation at utility scale or at CHP facilities, at existing sites, is preferable to the public safety risks posed by widespread outages or allowing the proliferation of diesel backup generators in an emergency."[3] The MTR Decision recognized that the risks of not contracting natural gas generation are "asymmetrical":

> *Failure to provide insurance to keep grid reliability is a far greater threat to public confidence and public health than running state-of-the-art fossil-fueled generators a few extra hours a year.* In addition, adding a small amount of efficient natural gas capacity will not necessarily lead to an increase in the generation from fossil-fueled units overall, but rather will likely lead to less dispatch of the higher-emitting and less efficient units."[4]

This asymmetrical risk is exacerbated by the fact that "outages and reliability problems can seriously erode public confidence in our environmental goals for the electric sector."[5]

Consequently, Calpine supports procurement of incremental gas capacity. The most straightforward way to encourage such procurement is to allow incremental gas capacity to count towards the MTR procurement mandates implemented through the MTR Decision, as the Staff

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[3] Decision ("D.") 21-06-035 at 42.

[4] *Id.* at 42 (emphasis added).

[5] *Id.* at 39.

Paper suggests.[6] Other potential approaches to procurement might include IOU procurement on behalf of all load through the IOUs' bundled procurement arms. Calpine comments on these and related issues below.

I. RESPONSE TO SPECIFIC QUESTIONS CONTAINED IN THE RULING

A. The Staff Paper Makes a Compelling Case that Gas Capacity Upgrades Could be Beneficial and Cost-Effective

Issue 1: The assumptions and conclusions of the RESOLVE analysis that includes gas capacity upgrades as a candidate resource.

Calpine believes that the manner in which gas capacity upgrades were represented in RESOLVE is reasonable, given the constraints of the model.

The 880 MW "High Potential" scenario shown in Table 2 may be higher than the actual available potential for gas upgrades.[7] It is Calpine's understanding that the "Low Potential" scenario reflects actual proposed upgrades at seven facilities.[8] The "High Potential" estimate assumes that similar upgrades could be available in proportion to the size of the entire combined cycle gas turbine ("CCGT") fleet. However, the actual upgrades in the "Low Potential" estimate may not be feasible for the rest of the CCGT fleet.[9]

With respect to the financing assumptions in Figure 4,[10] based on Calpine's experience, given the state's aggressive environmental policies and tendency to differentiate between how

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[6] Staff Paper at 16 ("If the Commission opts to allow rather than require gas capacity upgrades then this can likely be administered as part of the existing mid-term reliability procurement order in a relatively straightforward fashion. The Commission would need to formally allow the upgrades to be eligible resources, potentially to count towards the 7,000 MW NQC portion of the order that is not subject to specific requirements (long-duration storage, etc.).")

[7] Staff Paper at 9, Table 2.

[8] *Id.* at Table 2.

[9] For example, it may not be possible to upgrade turbines that already have been upgraded, or certain upgrades may require additional interconnection capacity that is not readily available.

[10] Staff Paper at 10, Figure 4.

new and existing resources are procured and compensated, developers of gas generation will generally seek to recover the costs of new investment through long-term contracts. To the extent the Commission is willing to authorize 25-year contracts for new gas generation, the lower cost assumptions in Figure 4 may be plausible. However, a 5-10 year cost recovery is more plausible and generally consistent with recent practice. As the Staff Paper notes:

> The risk of stranded investments associated with mid-term capacity expansions to existing gas power plants is a key consideration for Commission decision-making. This investment risk exists in cases where gas upgrades are valuable over the mid-term but may cease to be economic prior to their expected financing or cost recovery timeline.[11]

Investors share Energy Division's concerns about the risk of stranded gas assets over the longer term. To ensure that upgrades can be financed and built, the Commission should consider authorizing: (a) 5-10 year contracts, with accelerated recovery of all gas upgrade costs during that term; and/or (b) longer-term contracts paired with contractual commitments to transition to alternative fuels or technologies such as hydrogen or carbon capture and sequestration.

In addition, to the extent the Commission authorizes procurement of incremental gas capacity, it should also facilitate the procurement of the underlying existing MW for comparable terms. With the possible exception of completely new units, operating incremental gas capacity requires the continued operation of the underlying existing capacity, which suppliers generally will not risk operating at a loss to fulfill commitments for incremental gas capacity.

Calpine also appreciates the Staff Paper's recognition that its analysis does not capture potential heat rate improvements for the underlying existing capacity of the resources that could be upgraded. Turbine upgrades, for example, certainly have the potential to improve the heat

[11] *Id.* at 17.

rate of the existing gas fleet. This additional benefit of upgrades should be explored and valued in procurement if not in modeling.

More generally, regardless of the Staff Paper's specific assumptions about cost and potential and conclusions about cost-effectiveness, its conclusions ultimately should be tested in the market by opening procurement to gas capacity upgrades.

B. The Commission Should Allow Gas Capacity Upgrades to Count Towards the MTR Procurement Mandate

Issue 2: Whether gas capacity upgrades at existing sites should be considered as eligible resources for the procurement requirements of D.21-06-035? If so, which of the various procurement process steps of D.21-06-035 would need to be amended, and how?

Yes, the Commission should formally allow gas capacity upgrades to be eligible for MTR procurement mandate, as the Staff Report suggests.[12]

Commission and CEC analyses show that nearly the entire natural gas fleet must be retained in order to meet near- and mid-term reliability needs.[13] However, while the Commission's MTR need determination assumed 1 GW (nameplate) of gas plants will retire by 2026, the Staff Report warns that "even more units may seek retirement due to economics, age, ongoing maintenance or capital expenses, or – for CHP units – the loss of a thermal host and/or expiring long-term QF contract."[14] This potential early retirement of the gas fleet poses a real risk to mid-term reliability.[15]

The Commission has recognized that "some incremental and efficient natural gas generation at utility scale or at CHP facilities, at existing sites, is preferable to the public safety

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[12] *Id.* at 16.

[13] *Id*. Calpine recommended this approach in R.20-11-003. *See* R.20-11-003, Opening Brief of Calpine on Phase 2 Reliability for 2022-23, at 3-7 (Sept. 20, 2021).

[14] *Id.* at 15.

[15] *Id.*

risks posed by widespread outages or allowing the proliferation of diesel backup generators in an emergency",[16] and "[t]he CEC has identified another 200 MW of additional gas capacity that could potentially come online in 2022 or 2023 via efficiency and equipment upgrades if various procurement and permitting issues could be addressed."[17]

Allowing gas capacity upgrades to count towards at least a portion of the MTR procurement mandate is the most straightforward means to encourage procurement of gas capacity upgrades. This would require relatively modest changes to the MTR Decision, i.e., make gas capacity upgrades eligible for the 7,000 MW NQC unspecified portion of the procurement, as was contemplated in early drafts of both the MTR Decision and consistent with the treatment of incremental gas capacity for the procurement ordered in D.19-11-016.[18]

To the extent the Commission allows incremental gas capacity to count towards the MTR procurement mandate, Calpine respectfully requests that gas upgrades which were undertaken in 2020 (in expectation that they would be treated as "incremental" capacity for the MTR procurement mandate, as they were for the D.19-11-016 mandate) be allowed to count towards the MTR procurement mandate as well.

The MTR Decision should be further amended to allow IOU contracts for gas capacity to be approved via Tier 1 advice letter. Currently, the MTR Decision requires that the IOUs file Tier 3 advice letters to request cost recovery for any procurement conducted to meet the MTR procurement mandate. However, the Tier 3 advice letter process prevents a contract's approval from becoming final and non-appealable for many months if not years. The contract uncertainty

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[16] MTR Decision at 42.

[17] Staff Paper at 8.

[18] *See* Proposed Decision Requiring Procurement to Address Mid-Term Reliability (2023-2026) at 43-45 (May 21, 2021); D.19-11-016 at 43 (allowing incremental capacity from existing fossil-fuel resources to count toward the 3,300 MW procurement mandate).

associated with a Tier 3 process will very likely prevent generators from completing gas capacity upgrades in time to meet MTR procurement timeframes. Accordingly, the Commission should specify requirements for gas capacity upgrade contracts that can be approved via Tier 1 Advice Letter.

C. The Commission Should Not Require LSEs to Seek Non-Emitting Resources Before Contracting for Gas Capacity Upgrades

Issue 3: Whether load serving entities that wish to contract with gas capacity upgrades at existing sites, if permitted by the Commission, should be required to demonstrate that they first attempted to procure non-emitting resources. If so, what should this demonstration consist of, and on what timeframe?

No, the Commission should not require load serving entities ("LSEs") to demonstrate that they first attempted to procure non-emitting resources before contracting for gas capacity upgrades. This approach would be administratively burdensome as well as unnecessary. As the Staff Paper indicates, LSEs have already been hesitant to enter into mid- or long-term gas contracts, which has caused the California Independent System Operator ("CAISO") to designate a number of units as reliability must run ("RMR") because of their importance for local grid reliability.[19] To ensure mid-term reliability, incremental gas capacity procurement should be encouraged, not inhibited.

Further, D.19-11-016 placed no cap on incremental gas capacity to meet that decision's procurement mandate, nor did it prescribe the metrics that LSEs must use to compare different types of resources.[20] For MTR procurement, LSEs should be similarly trusted to assess the attractiveness of gas capacity upgrades accurately in light of the state's environmental policies. It is reasonable to assume that LSEs will only procure gas upgrades that are consistent with the

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[19] Staff Report at 6.

[20] *See* D.19-11-016 at 43-45.

LSEs' overall procurement and environmental goals, which ultimately must conform to IRP targets.

If the Commission wishes to constrain incremental gas capacity procurement, the Commission should limit procurement to the maximum amount that the Staff Report found cost-effective (i.e., 880 MW), perhaps allocated to LSEs on a load share basis. Importantly, any such cap should apply only to incremental gas capacity and not any underlying existing capacity procured along with the incremental gas capacity

D. Gas Capacity Upgrades Will Not Impact Disadvantaged Communities

Issue 4: If the Commission allows gas capacity upgrades at existing sites, whether the Commission should restrict or prohibit gas capacity upgrades in disadvantaged communities, as defined by the CalEnviroScreen tool, or impose some other/additional criteria.

No, the Commission should not limit gas capacity upgrades in disadvantaged communities ("DACs").

The Staff Paper acknowledges that equipment and software upgrades can "decrease the rate of criteria pollutant emissions,"[21] i.e., they could reduce emissions in DACs and elsewhere. In addition, while upgrades might increase dispatch and hence overall emissions, they also could lead to fewer starts, which entail higher emissions rates than steady-state operations.

In addition, as Calpine has repeatedly highlighted, detailed air modeling shows that the impact of emissions from gas generation in DACs is (1) relatively minor, and (2) not necessarily highest proximate to where emissions occur.[22] At a minimum, any limitations should reflect the fact that the impact of emissions from gas generation on local concentrations of pollutants, such

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[21] Staff Paper at 16.

[22] *See* Comments of Calpine on Proposed Preferred System Plan at 5 (Sept. 27, 2021); Ex. Calpine-1, Reply Testimony of Christopher A. Emery on Behalf of Calpine Corporation, Exh. B, R.20-11-003 (Jan. 19, 2021).

as ozone and particulate matter, are highly location and context dependent. For example, emissions of NOx from gas generation might not contribute to the secondary formation of PM if volatile organic compounds ("VOCs") are not present in the right mix.

II. ADDITIONAL COMMENTS ON THE STAFF PAPER

A. Retiring California's Gas Fleet may Increase Regional Emissions

Calpine appreciates the Staff Paper's recognition that California does not exist in a vacuum: i.e., while gas capacity upgrades in California may modestly increase emissions in California, they have the potential to reduce emissions regionally by reducing the need for imports to California backed by gas or coal generation. Calpine believes that this point bears greater attention in the consideration of gas capacity upgrades as well as more generally. A push to retire existing gas generation in California may yield limited environmental benefits if it results in the state's increased reliance on imports of fossil generation.

B. There are Significant Challenges Associated with Transitioning Gas Generation to Hydrogen; Carbon Capture and Sequestration has Greater Potential to Decarbonize Gas Generation

The Staff Paper accurately characterizes some of the challenges associated with transitioning gas generation to hydrogen:

> [R]equiring turbine modification to enable hydrogen blending, producing hydrogen fuel via new electrolyzers, and adding hydrogen on-site storage and/or transportation infrastructure all add significant costs and development risks to gas capacity upgrades. It will be helpful to have more analysis on the cost, potential, and use cases for zero carbon fuels like green hydrogen in decarbonizing California's economy.[23]

There are additional challenges associated with developing the renewable generation that would be required to produce enough green hydrogen to power a significant portion of the gas

[23] Staff Paper at 17.

generation fleet. For example, Calpine estimates that 4 GW of solar would be required to produce enough hydrogen to fuel a 500 MW CCGT operating at 60% capacity factor.[24] Developing these renewables could be difficult in light of interconnection and land use challenges associated with a substantial volume of renewables development to meet electricity demand directly as well any demand increases associated with the electrification of other sectors.

As Calpine has indicated repeatedly in this and other proceedings, Calpine is more sanguine about the potential for carbon capture and sequestration ("CCS") to contribute to meaningful decarbonization of gas generation.[25] To that end, Calpine recently applied for and was awarded multiple Department of Energy grants to fund CCS pilots.[26] Calpine looks forward to sharing additional information about these pilots and CCS more generally in the next cycle of IRP.

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[24] A 4 GW solar PV array operating with a 25% capacity factor produces an average of 24 GWh each day (capacity factor based on California average from EIA 2018). Electrolysis of hydrogen using the solar generation results in approximately 395,570 kg hydrogen per day, or 53,196 MMBtu per day (assumes electrolyzer conversion efficiency of 65% from GE 2019). This hydrogen could be used to generate approximately 7.257 GWh/day from a moderately efficient CCGT operating at a 7.33 $MMBTU_{HHV}$/MWh heat rate, which corresponds to a 500 MW natural gas combined-cycle unit operating at a 60% capacity factor (heat rate drawn from CEC 2020).

[25] *See* R.20-05-003, Comments of Calpine Corporation on the Proposed and Alternative Proposed Decision Requiring Procurement to Address Mid-Term Reliability (2023-2026), at 10 (June 10, 2021); R.20-11-003, Opening Brief of Calpine on Phase 2 Reliability for 2022-23, at n.18 (Sept. 20, 2021).

[26] https://www.energy.gov/fecm/articles/funding-opportunity-announcement-2515-carbon-capture-rd-natural-gas-and-industrial

Respectfully submitted,

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