UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Pacific Gas & Electric – **La Paloma Unexecuted LGIA**	)))	**Docket No. ER21-2592-___**

INITIAL BRIEF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

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I. Introduction and Executive Summary

The California Independent System Operator Corporation ("CAISO")[1] submits this initial brief pursuant to the Federal Energy Regulatory Commission's ("Commission") December 15, 2022 *Order Lifting Abeyance and Establishing Paper Hearing Briefing Schedule* ("December 15 Order"). The CAISO's tariff expressly addresses conversions from two-party to three-party generator interconnection agreements ("GIA"), including the conversion that gave rise to this dispute—the unexecuted GIA ("Replacement Interconnection Agreement") filed by Pacific Gas and Electric Company ("PG&E") among CXA La Paloma, LLC ("La Paloma"),[2] the CAISO, and PG&E. Based on the CAISO's tariff provisions and good utility practice, the appropriate interconnection service capacity for the Replacement Interconnection Agreement is 1,062 MW.

In accordance with the *Order of Chief Judge Adopting Protective Order* issued in this proceeding on March 16, 2022, the CAISO is designating certain Attachments to this Brief as Privileged Material. Information related to La Paloma's generating facility information, MOD-025 data, and confidential contracts have been marked as Privileged Information in the attachments. The CAISO also is designating certain Attachments pertaining to specific generator information as Critical Energy/Electric Infrastructure Information ("CEII"), as designated in the Table of Attachments included as Attachment 1.

The Replacement Interconnection Agreement at issue in this proceeding replaces the original GIA between La Paloma and PG&E terminated in Docket

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1 Capitalized terms not otherwise defined herein have the meanings set forth in Appendix A to the CAISO tariff. References herein to specific tariff sections are references to sections of the CAISO tariff.

2 La Paloma refers to CXA La Paloma, LLC, its predecessors in interest, and its representatives.

No. ER21-2064.[3] The CAISO's tariff has specific provisions to effect the conversion from a two-party to a three-party GIA:[4] (1) the generator owner attests to whether the facility will remain substantially unchanged; (2) the CAISO confirms the information included in the attestation; and (3) the process results in either interconnection service capacity reflecting the unchanged facility's capacity or the generator owner submitting an interconnection request if the capacity of the facility will substantially change.[5] The tariff provisions setting forth this process constitute a filed rate[6] that precludes La Paloma from obtaining more interconnection service capacity than the facility's generating capability.

La Paloma took the steps required by the conversion process in the CAISO tariff ("Section 25 Process") by submitting a conversion request for the Replacement Interconnection Agreement seeking an interconnection service capacity of 1,060 MW, and submitting an affidavit attesting that the facility's capacity would remain unchanged at approximately 1,065 MW.[7] The CAISO, pursuant to Section 25, verified La Paloma's attestation utilizing a standardized conversion checklist which compares multiple data points to determine the

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[3] The Commission approved that termination under La Paloma's protest, effective on August 3, 2021. *Pacific Gas and Electric Co.*, 176 FERC ¶ 61,067 (2021). The original GIA was filed at the Commission as part of a settlement between PG&E and La Paloma. The original GIA is included as Attachment 2, and the documents pertaining to the settlement are available in Docket No. ER02-60-000.

[4] Section 25 of the CAISO tariff describes the processes applicable to all types of generators interconnecting to the CAISO grid, including those generating units whose total generation was previously sold to a Participating Transmission Owner ("Participating TO") and now will be sold in the wholesale market, *i.e.* two- to three-party GIA conversions (Section 25.1(d)).

[5] Section 25.1.2 of the CAISO tariff.

[6] *Imperial Irrigation Dist. v. California Indep. Sys. Operator Corp.*, 146 F. Supp. 3d 1217, 1226 (S.D. Cal. 2015). (stating that the filed rate doctrine "provides that the terms of a federally-regulated entity's tariff 'are considered to be "the law" and to therefore "conclusively and exclusively enumerate the rights and liabilities" of the contracting parties,'" citing *California ex rel. Lockyer v. Dynegy, Inc.*, 375 F.3d 831, 853 (9th Cir. 2004)).

[7] Attachments 4 and 5. The conversion request utilizes the same form as a new interconnection request and the generic terms may be used interchangeably.

appropriate interconnection service capacity.[8] Most critically, this checklist ensures that the generating capability and electrical characteristics of a generation facility subject to the conversion process have not substantially changed nor will they substantially change. This is the standard to determine whether the facility may proceed with a GIA or will need to submit a new interconnection request under Appendix DD of the CAISO tariff.[9] Four months after its submissions, La Paloma contradicted the information previously provided to the CAISO in compliance with the tariff and claimed it was due additional interconnection service capacity based solely on its original GIA, preventing the successful completion of negotiations for the Replacement Interconnection Agreement.

Contrary to the express provisions of Section 25 of the CAISO tariff and Commission precedent, La Paloma argues that it should now be entitled to the interconnection service capacity it originally "contracted for."[10] But Commission precedent holds that the interconnection service capacity in a GIA does not confer a property right, and that where an interconnection customer *builds* less generating facility capacity than the amount for which it requested interconnection service, it does not retain that "surplus" interconnection service capacity indefinitely.[11] Interconnection customers that do not construct their generating facilities to the level of their requested interconnection service capacity and confirm that their generating facility's capacity is less than their "contracted for" interconnection service capacity, do not get to keep it.[12]

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8 The conversion checklist for La Paloma's facility is included as Attachment 6. A more thorough discussion of this process is included in Section II.B of this brief.

9 *See* Section 25 of the CAISO tariff.

10 La Paloma Protest at 4.

11 C*alWind Resources Inc. v. California Independent System Operator Corp.*, 146 FERC ¶ 61,121, at PP 33 *et seq.* (2014). *Reform of Generator Interconnection Procedures and Agreements*, Order No. 845, 163 FERC ¶ 61,043 at PP 491, 493 (2018)("Order No. 845"), *errata notice*, 167 FERC ¶ 61,123, *order on reh'g*, Order No. 845-A, 166 FERC ¶ 61,137 (2019)("Order No. 845-A"), *errata notice*, 167 FERC ¶ 61,124*, order on reh'g*, Order No. 845-B, 168 FERC ¶ 61,092 (2019).

12 *Id*. *See also* Section 3.4 of Appendix DD of the CAISO tariff.

In addition to other information in the original GIA and North American Electric Reliability Corporation ("NERC") standards submissions contradicting La Paloma's claims, other evidence—testing and operational data regarding the units and other La Paloma statements and submissions—unequivocally demonstrates that La Paloma did not construct a generating facility that could, in any circumstance, utilize 1,160 MW of interconnection service capacity. La Paloma never received any permit to operate its generating facility at its now-claimed capacity of 1,160 MW or demonstrated it could do so. La Paloma has continually submitted documentation to the CAISO and others confirming this fact. This includes generating facility modeling data that La Paloma's attesting expert submitted to the CAISO, contradicting his affidavit in this proceeding. To the extent La Paloma now claims its generating facility is capable of generating 1,160 MW, its assertions are (1) inconsistent with representations made to the CAISO, PG&E, and the Commission, pursuant to tariff and NERC standards, and (2) inconsistent with the results of actual operations and testing of the facility.

In numerous submissions to the CAISO as well as filings with the Commission and other governmental authorities, La Paloma has repeatedly represented the capacity of its generation facility is far less than the 1,160 MW it now claims. If the Commission were to rule in favor of La Paloma notwithstanding its prior factual submissions to the CAISO, it would significantly undermine the ability of independent system operators and regional transmission organizations to rely upon the accuracy of data provided by customers in compliance with their Commission-approved tariffs. At a minimum, the ample evidence in this Brief and its supporting Attachments as to La Paloma's inconsistent representations of its facility's capacity raise significant questions about the credibility of La Paloma's claims in this proceeding.

Any order requiring the CAISO to provide La Paloma with additional interconnection service capacity has the potential to significantly harm other interconnection customers. It would require the Commission to direct the construction of necessary network upgrades that would have to be funded after the fact in order to avoid taking back interconnection service capacity from other generators (operating to their actual generating capabilities) and would raise issues as to who would have to fund these upgrades. Such a direction would be contrary to Order No. 845-A, where the Commission confirmed that, "by definition, surplus interconnection service is only available up to the level that can be accommodated without requiring the construction of new network upgrades."[13]

The Commission's December 15 Order directed parties to respond to a series of questions aimed at resolving an issue of material fact. The CAISO responds to these questions below, demonstrating: (A) the CAISO has tariff provisions applicable to this process that comply with the Commission's surplus interconnection service capacity policy, which does not support La Paloma's claims in this case; (B) La Paloma has provided no credible evidence that it constructed the capacity it now claims; (C) granting La Paloma this excess capacity would harm ratepayers; and finally (D) La Paloma has no right to damages under applicable CAISO tariff provisions governed by the filed rate doctrine.

II. Discussion

The Commission found that the dispute among La Paloma, the CAISO, and PG&E regarding the amount of interconnection service capacity that the Replacement Interconnection Agreement should reflect raises an issue of material fact that cannot be resolved on the record.[14] Namely, the parties do not agree on the capacity of the constructed generating facility. The record in this case, including evidence provided in this paper hearing process, will show the CAISO has relied on representations made by La Paloma and actual operating data from the facility to determine what generating capacity La Paloma actually constructed.

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13 Order No. 845-A at P 138.

14 December 15 Order at P 7.

Although the capacity value written in the original two-party GIA is a factor the CAISO considers in its analysis to determine the amount of capacity that should be reflected in a conversion to a three-party GIA, tariff Section 25.1.2 makes clear that the CAISO's determination is based on a facility's "total generating capability and electrical characteristics."[15] The tariff does not even require the CAISO to consider the amount specified in the original GIA in making this determination, let alone make it a determinative factor. The interconnection service capacity in the now-terminated original GIA reflects what La Paloma requested 20 years ago before construction, and the GIA also contains conflicting information about the units comprising the facility, which suggests a total capacity at the facility of 1,020 MW.[16] The CAISO tariff recognizes that generators may have requested more capacity than what was ultimately built, and does not allow for a rollover of interconnection service capacity without an analysis of the generating facility capacity. That is the situation here: The evidence, including numerous prior statements and regulatory submissions by La Paloma, as well as testing and operational data, show that the facility La Paloma actually constructed has materially less capacity than 1,160 MW.

La Paloma claims in its pleadings in this proceeding that it constructed a facility of 1,160 MW, in line with the original GIA's interconnection service capacity.[17] La Paloma attempts to support that contention only by relying on the nameplate of each unit that allegedly includes an output rating of 340 MVA per unit, which, when converted at a power factor of 0.85, produces a capacity of 289 MW per unit, or 1,156 MW total for the four units at the facility.[18]

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[15] Section 25.1.2 of the CAISO tariff.

[16] The original GIA includes conflicting information in Appendix E. It indicates an interconnection service capacity of 1,160,000 kW, but also contemplates a facility containing four units rated at 300 MVA with a 0.85 Power Factor, or 255 MW, which would result in only 1,020 MW of total capacity. La Paloma ignores this description of the generating facility characteristics specified in the GIA. The original GIA is included as Attachment 2.

[17] *Id.*

[18] La Paloma Protest at 1, attach. A, Affidavit of Terry Benson, ¶ 5. La Paloma is requesting an interconnection service capacity of 1,160 based on the interconnection service

La Paloma's claim regarding the nameplate capacity of each unit is belied by other representations and other information contained in the original GIA. Terry Benson, Facility Manager for the La Paloma generating facility, attests that units at La Paloma's facility has a rated output of 340 MVA. In a separate proceeding, Mr. Benson states that units at La Paloma have a rated output of "300/340 MVA" and that the larger of the two ratings should be used based on the class of temperature rise equipment that was apparently installed (Class B vs. Class F, the latter corresponding with 340 MVA).[19] This second explanation requires an assumption about which temperature rise equipment La Paloma installed. Regardless of what Mr. Benson claims, La Paloma's recent MOD-025-02 data, submitted to PG&E pursuant to the North American Electric Reliability Corporation (NERC) standard, contradicts Mr. Benson's claim that Class F equipment was installed. The data expressly states that Class B equipment was installed, and it identifies a unit output rating of 300 MVA in its characteristic curves.[20]

Mr. Benson and La Paloma's claims about output ratings are also undermined by Mr. Benson himself in the data submitted to the CAISO via a process in which generator owners submit generating facility data pursuant to the CAISO Business Practice Manual for the Transmission Planning Process ("BPM Section 10 Process").[21] In these documents, of which Mr. Benson is listed as the contact person, each of the four units is listed as having a "Total Generating Facility Gross Nameplate Capacity" of 300 MVA and a "Maximum Total

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capacity in the original GIA, utilizing its reading of the nameplate to support that it constructed a facility nominally close to that capacity number.

[19] *Complaint of CXA La Paloma, LLC*, EL23-24, attach. A, Affidavit of Terry Benson, ¶ 5 (2023).

[20] Attachment 11. This most recent MOD-025-02 document does include a table indicating that the units have an output rating of 340 MVA. However, the data in the rest of the document does not support that contention. *See, for example*, characteristic curves included as Appendix B in this Attachment, which show an output rating of 300,00 kVA and Class B temperature rise equipment.

[21] Section 10 of the CAISO's BPM for the Transmission Planning Process.

Generating Facility Gross Output" of 255 MW. Moreover, the original GIA expressly specifies four units at 300 MVA, which, utilizing La Paloma's own math at a power factor of 0.85, would result in a generating facility capacity of 1,020 MW. The original GIA confirms this by listing the generating facility as being comprised of four units at 255 MW with a 0.85 Power Factor.[22] These data points in the original GIA conflict with the interconnection service capacity value La Paloma relies on from the same appendix, only demonstrating the unreliability of the original GIA as a source.

Under the CAISO's tariff, when a resource seeks to convert from a two-party to three-party GIA, the CAISO evaluates whether the generating capacity and electrical characteristics of the facility will remain substantially unchanged, in contrast to the more robust study process outlined in other tariff sections.[23] La Paloma alleges instead that FERC Order No. 845 entitles them to surplus interconnection service capacity. La Paloma's allegations fail under this standard as well, as they never constructed a facility close to what they now claim to be capable of producing. Order No. 845 does not afford surplus interconnection service rights in such circumstances.

FERC Order No. 845, on which La Paloma relies, provides that surplus interconnection service capacity is "intended to increase utilization of existing, underutilized interconnection service provided at a particular point of interconnection."[24] In practical terms, this means that, some portion of that interconnection service capacity may not be utilized if a generating facility was constructed as studied but routinely performs at a lower capacity. But La Paloma never constructed and never claimed until now—20 years later—that it constructed a generating facility with a capacity of 1,160 MW. No such surplus

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[22] *See supra* footnote 16.

[23] *See* Section 25.1.2.2 of the CAISO tariff, directing converting facilities to the GIDAP, Appendix DD of the CAISO tariff in circumstances where there will be a substantial change.

[24] Order No. 845, 163 FERC ¶ 61,043 at P 473.

interconnection service capacity has ever existed for La Paloma. La Paloma has continually represented in multiple venues, including in submissions to the CAISO to comply with tariff requirements, that its generating facility capacity is lower than its now-requested interconnection service capacity.[25] Even as recently as September 8, 2022, after PG&E filed the unexecuted Replacement Interconnection Agreement, La Paloma submitted generator modeling data to the CAISO indicating a 300 MVA output rating and 0.85 Power Factor for its units, which equates to a total generating capacity of 1,020 MW.[26]

A. The CAISO's Commission-approved tariff provisions govern conversions from two-party to three-party generator interconnection agreements, and constitute a filed rate.

Section 25 of the CAISO tariff governs conversions from two-party to three-party GIAs. It applies here and does not allow for an alternative outcome than that already identified by the CAISO: The interconnection service capacity for the Replacement Interconnection Agreement is 1,062 MW. La Paloma conceded it is subject to these tariff provisions when it submitted its affidavit for the conversion.[27] The filed rate doctrine provides that the terms of the CAISO's tariff, which are regulated by the Commission, are conclusive as to the rights and liabilities of the parties.[28] Filed rates do not exclusively refer to dollar values, but also to tariff provisions that affect rates.[29] Courts apply this "stringent rule," in

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[25] These representations are described at length below. *See also* Attachment 1, Table of Attachments.

[26] Attachment 7. *See* pgs. 6, 19, 32, 45 for Units 1-4, respectively.

[27] *See* Attachment 5.

[28] *Imperial Irrigation Dist. v. California Indep. Sys. Operator Corp.*, 146 F. Supp. 3d 1217, 1226 (S.D. Cal. 2015).

[29] *Oklahoma Gas & Elec. Co. v. FERC*, 11 F.4th 821, 829 (D.C. Cir. 2021) (finding that filed rates are not limited to "rates" *per se* but also applies to matters that directly affect rates). *See also, Imperial Irrigation Dist. v. California Indep. Sys. Operator Corp.*, 146 F. Supp. 3d 1217, 1226-1227 (S.D. Cal. 2015) (noting that "[w]hile the filed rate doctrine is couched in terms of 'rates,' it is not read so narrowly as to apply only to claims dealing specifically with rates charged.")

support of the Congressional purpose of preventing unjust discrimination, which would otherwise be defeated if parties could effect other outcomes.[30] Doing so would effectively give La Paloma a different rate than the filed rate, providing for disparate treatment. The Commission has "no discretion to waive the operation of a filed rate or to retroactively change or adjust a rate for good cause or for any other equitable considerations,"[31] neither of which would apply in any case to La Paloma's allegations, particularly in light of the egregious misrepresentation of its generating facility's capabilities in this proceeding, contradicting all prior evidence.

The Commission asks:

(1) CAISO asserts that the Project's net generating capacity at the point of interconnection has not exceeded 1,062 MW. The proposed interconnection agreement reduces La Paloma's interconnection service capacity from 1,160 MW to 1,062 MW.

a. Please explain which tariff and/or manuals, if any, govern the renegotiation of an expiring generator interconnection agreement.

Section 25 of the CAISO tariff governs conversions from a two-party GIA to a three-party GIA. Specifically, Section 25.1 describes the applicability of the section to an existing generating unit:

> This Section 25 and Appendix U (the Standard Large Generator Interconnection Procedures (LGIP)), Appendix Y (the Generator Interconnection Procedures (GIP)), Appendix S (the Small Generator Interconnection Procedures (SGIP)), Appendix W, or Appendix DD (the Generator Interconnection and Deliverability Allocation Procedures (GIDAP)), as applicable, shall apply to:…(d) each existing Generating Unit connected to the CAISO Controlled Grid whose total Generation was previously sold to a Participating TO or on-site customer but whose Generation, or any portion thereof, will now be sold in the wholesale market, subject to Section 25.1.2;…[32]

30 *CallerID4u, Inc. v. MCI Commc'ns Servs. Inc.,* 880 F.3d 1048, 1053 (9th Cir. 2018).

31 *Old Dominion Elec. Coop. v. FERC*, 892 F.3d 1223, 1230 (D.C. Cir. 2018).

32 Section 25.1 of the CAISO Tariff.

These provisions apply when such an agreement expires or is terminated, regardless of whether the generating facility has an existing relationship with the CAISO following the execution of that two-party agreement.[33] Section 25.1.2 describes the process for submitting an affidavit and beginning the conversion process:

> If the owner of a Generating Unit described in Section 25.1(d), (e), or (f) or its designee, represents that the total generating capability and electrical characteristics of the Generating Unit will be substantially unchanged, then that entity must submit an affidavit to the CAISO and the applicable Participating TO representing that the total generating capability and electrical characteristics of the Generating Unit have remained substantially unchanged. However, if there is any change to the total generating capability and electrical characteristics of the Generating Unit, the affidavit shall include supporting information describing any such changes and a $50,000 deposit for the study. The CAISO, in coordination with the applicable Participating TO, will evaluate whether the total generating capability or electrical characteristics of the Generating Unit have substantially changed or will substantially change. The CAISO may engage the services of the applicable Participating TO in conducting such verification activities. Costs incurred by the CAISO and Participating TO (if any) shall be borne by the party making the request under Section 25.1.2, and such costs shall be included in a CAISO invoice for verification activities.[34]

These procedures are designed to ease the transition from a two-party to three-party GIA by not always requiring the generating facility to go through the more arduous process of utilizing the standardized interconnection process for new generators.[35] To the extent La Paloma believes these processes are

[33] Previously applicable only to Qualifying Facilities, the CAISO clarified in 2011 that this provision "govern[s] the application of the ISO's interconnection procedures once a generating unit's prior power sales arrangements to a participating transmission owner or on-site customer have terminated." Transmittal Letter, ER11-2574. The Commission accepted these changes. 134 FERC ¶ 61,140, *subject to further revisions* (to other unrelated provisions in the tariff clarification filing), accepted by Letter Order, January 12, 2012.

[34] Section 25.1.2 of the CAISO tariff.

[35] Over time, the CAISO has received Commission authorization to expand the scope of the application in order to facilitate an easier transition for generating facilities in multiple common situations. *See, for example:* ER11-2574-002, Letter Order Jan 12, 2012. (accepting tariff amendment that extended the applicability to all existing generators) and ER22-878, Letter Order

inapplicable to its particular case, there is no alternate process for entering into an interconnection agreement with the CAISO short of submitting an interconnection request, which would require more extensive studies and deposits. La Paloma has not submitted a request to the CAISO for anything but a GIA conversion, and it requested an interconnection service capacity of 1,060 MW in its request.[36] La Paloma submitted the required affidavit under Section 25, and attested that the generating facility would remain substantially unchanged at approximately 1,065 MW, essentially conceding it is subject to these provisions.[37] By now claiming a different constructed capacity (even though La Paloma cannot generate that amount), La Paloma attempts to circumvent the tariff requirements with their protest and avoid the study deposit, required additional studies, and ultimately new interconnection request for the additional capacity.

> *b. Please explain which tariff and/or manuals, if any, govern a decrease to the interconnection service capacity provided under an expiring generator interconnection agreement, and explain under which conditions interconnection service capacity may be decreased from the amount specified in the expiring generator interconnection agreement.*

The CAISO does not actively decrease the interconnection service capacity provided under an expiring generator interconnection agreement. Instead, the conversion process relies on confirming the characteristics of the facility, including those attested to by representatives of the facility in the aforementioned required affidavit. The CAISO also evaluates the generator's energy production over the last several years, test data, and submissions from generators to CAISO processes. Per Section 25.1.2 of the CAISO tariff, the

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March 25, 2022 (accepting tariff amendment to extend the applicability to repowering generators). *See also* Section 4 of the CAISO's BPM for Generator Management.

[36] La Paloma initially submitted an interconnection request for a conversion requesting 1,060 MW of interconnection service capacity, in conjunction with the affidavit specified in Section 25 of the CAISO tariff which attested to an unchanged capacity of approximately 1,065 MW. Attachments 4 and 5.

[37] Attachment 5.

CAISO and the applicable Participating TO will evaluate whether the total generating capability or electrical characteristics of the facility have substantially changed or will substantially change. If the CAISO and the applicable Participating TO confirm that the electrical characteristics are substantially unchanged, then that request will not be placed into the interconnection queue, and the parties will move forward to execute a CAISO GIA.[38] If the CAISO and the applicable Participating TO cannot confirm that the total capability and electrical characteristics are and will be substantially unchanged, then the owner will be required to submit an interconnection request and comply with Appendix DD to the CAISO tariff for new interconnection requests.[39]

La Paloma argues that the surplus interconnection service provisions of Order No. 845 apply to this case, implying Appendix DD, Section 3.4, governing surplus interconnection service capacity would govern in this instance.[40] Although a generating facility may use or transfer any such capacity, *when such surplus capacity exists,* the section is inapposite here because La Paloma is not entitled to any surplus interconnection service capacity above 1,062 MW because none exists. La Paloma did not construct a facility that would have created such surplus interconnection service.

Section 3.4 of Appendix DD is the CAISO's provision governing surplus interconnection service. The Commission approved the provision in compliance with Order No. 845. Section 3.4 states that surplus interconnection service capacity "may not exceed the original Interconnection Customer's constructed Generating Facility Capacity, regardless of the Interconnection Service Capacity it requested in its Interconnection Request or memorialized in its GIA." Generating Facility Capacity is defined as "[t]he net capacity of the Generating Facility and the aggregate net capacity of the Generating Facility where it

[38] Section 25.1.2.1 of the CAISO tariff.

[39] Section 25.1.2.2 of the CAISO tariff.

[40] La Paloma Protest at 6.

includes multiple energy production devices."[41] Contrary to La Paloma's assertions, nameplate capacity alone is irrelevant to the constructed capacity.

Several facts contradict La Paloma's claim that the nameplate capacity demonstrates the constructed generating capacity. The CAISO discusses these in greater detail later in this brief. In short, (a) La Paloma's original interconnection agreement only contemplates a facility with four units rated at 300 MVA and with a generating capacity of 255 MW each;[42] (b) La Paloma only sought necessary permits from the California Energy Commission ("CEC"), Environmental Protection Agency ("EPA"), and San Joaquin Valley Air Pollution Control District for a capacity up to 1,048 MW;[43] (c) La Paloma executed a Participating Generator Agreement ("PGA") with the CAISO, which was subsequently filed at the Commission, indicating a nameplate rating of 1,022.4;[44] (d) La Paloma's recent PMax testing supports approximately 1,066 MW of capacity;[45] (e) La Paloma itself accordingly registered its PMax in the Master File at a total capacity of 1,066 MW;[46] (f) La Paloma submitted generating facility modeling data to the CAISO that reflects an MVA rating of 300 MVA and 255 MW

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41 Appendix A of the CAISO Tariff.

42 Attachment 2.

43 Attachments 12, 13, 14, and 15. Due to the size of the file, Attachment 12 contains the Executive Summary excerpted from La Paloma's Application for Certification. The complete document is available in hard copy through the CEC's library. Attachment 13 contains an excerpt of the CEC's Decision on the La Paloma Generating Project Application for Certification, specifically Section I. Project Purpose and Description, finding the plant to be 1,048 MW, and Section V. Engineering Assessment, which describes in Table 1 the Major Equipment List that the four generators have a 300 MVA output rating. The complete CEC Decision is available in CEC docket 98-AFC-02, or at https://efiling.energy.ca.gov/GetDocument.aspx?tn=35900&DocumentContentId=66565. Attachment 14 contains an excerpt of La Paloma's Title V permit specifically listing the permit number and capacity of each unit. The complete document is available at http://www.valleyair.org/notices/Docs/2017/11-06-17_(S-1162576)/S-1162576.pdf.

44 Attachment 3, Schedule 1. The original PGA indicated a capacity of 1,022 MW total. This was filed in Docket No. ER01-1611. The Commission accepted the PGA by letter order (May 4, 2001). The CAISO does not submit amendments to pro forma PGAs to the Commission.

45 Attachment 9.

46 Attachment 8. *See* pg. 8. PMax changes in Master File are typically the result of a PMax test. To increase PMax, the CAISO will confirm the resource has been tested for that proposed amount to ensure it is consistent with the physical capability of the resource.

per unit;[47] and (g) La Paloma's MOD-025-02 data only demonstrates a generating capability of approximately 255 MW per unit.[48] La Paloma also has made representations before the Commission and federal courts indicating its nameplate is lower than the MW capacity it now claims.[49]

La Paloma's assertions attempt to capture additional value for a facility based on an inaccurate reading of the tariff. Even assuming *arguendo* La Paloma has surplus interconnection service capacity, which it does not, it would have forfeited that capacity based on the course of its dealings. La Paloma would no longer have any reasonable expectation of utilizing it because the policies set forth in Order No. 845 and Order No. 845-A and provisions of the CAISO tariff. In Order No. 845, the Commission favorably noted the CAISO's statement that:

> Commission precedent holds that the interconnection service capacity does not confer a property right, and that where an interconnection customer builds less generating facility capacity than that for which it requested interconnection service, it does not retain that interconnection service capacity indefinitely, and transmission providers like CAISO may subsequently remove it from their base case.[50]

The Commission "agree[d] with CAISO that where the original interconnection customer, for example, reduces the generating facility capacity of its facility from what was originally proposed for interconnection, it would not retain rights indefinitely to any excess interconnection service capacity thus created."[51]

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[47] Attachment 7. *See* pgs. 6, 19, 32, 45 for Units 1-4 respectively.

[48] Attachments 10 and 11.

[49] Attachments 16 and 17. *See also, infra* footnote 66.

[50] Order No. 845 at P 491, *citing* CAISO comments and *CalWind Resources Inc. v. California Independent System Operator Corp.,* 146 FERC ¶ 61,121, at PP 33 *et seq.* (2014). As explained below, in this case, the CAISO is using a 1,062 MW capacity for the facility in its base case reflecting information provided by La Paloma itself.

[51] Order No. 845 at P 493; *see also* Order No. 845-A at P 146.

The CAISO tariff, in turn, states that surplus interconnection service capacity "may not exceed the original Interconnection Customer's constructed Generating Facility Capacity, regardless of the Interconnection Service Capacity it requested in its Interconnection Request or memorialized in its GIA."[52] In this case, all the evidence confirms the CAISO's finding that La Paloma's constructed Generating Facility Capacity is far less than the 1,160 MW now claimed by La Paloma. La Paloma has not demonstrated that it actually constructed more than 1,062 MW. Thus, ordering the CAISO to provide La Paloma 1,160 MW would be contrary to Order No. 845's findings on the impact of reducing a generating facility's capacity below what was originally proposed for interconnection. Such an order would run afoul of the filed rate doctrine, which compels only the result identified in the CAISO's Commission-approved tariff, *i.e.*, the Section 25 Process.

The CAISO notes, solely for the sake of argument, that even if the capacity of the La Paloma facility were reduced below 1,160 MW after the facility commenced operation, La Paloma "would not retain rights indefinitely to any excess interconnection service capacity thus created" under Order No. 845.[53] The evidence, including numerous representations of La Paloma before its facility entered service, shows that is not the fact pattern in this case. There is another key Commission finding in the Order No. 845 rulemaking confirming that La Paloma is not entitled to supplemental interconnection service. In Order No. 845-A, the Commission clarified that, "by definition, surplus interconnection service is only available up to the level that can be accommodated without requiring the construction of new network upgrades."[54] In order to avoid depriving existing generators of interconnection service capacity they already have, network upgrades would need to be built on the CAISO controlled grid in

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52 Section 3.4 of Appendix DD of the CAISO tariff.

53 *See supra* footnote 51.

54 Order No. 845-A at P 138.

order for La Paloma to receive interconnection service capacity up to 1,160 MW. Under these circumstances, surplus interconnection service is not available.

B. La Paloma has provided no credible evidence that it has constructed a facility with 1,160 MW of capacity, and has continually made representations of a lower capacity.

La Paloma exclusively relies on an interpretation of the nameplate of one of its four units to demonstrate that it constructed a facility with a total capacity of 1,160 MW.[55] This interpretation is contradicted by other data,[56] including nearly every other piece of data La Paloma has provided in other venues, consistently describing the generating capabilities of its facility as being much less than 1,160 MW. La Paloma's claim is further contradicted by actual testing and operational data from the facility.

Beyond test data, and relevant to understanding the constructed capacity of the facility, La Paloma's Application for Certification to the CEC indicated a plant capacity of 1,048 MW and described the individual units as having an output rating of 300 MVA.[57] This license is necessary for any power plant in California larger than 50 MW and is required given the significant effects on the environment from plants this large. The data contained in the CEC Application for Certification is critical to the point that even the original GIA calls out the application as the place to find more information on the generating facility.[58] Following approval of a plant, the project must continue to comply with all provisions in the associated license, and any operations outside the conditions of

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[55] La Paloma Protest at 1, attach. A, Affidavit of Terry Benson, ¶ 5.

[56] For example, La Paloma reads its nameplate to state that Class F temperature rise equipment was installed, which would lead to the use of 340 MVA when calculating MW capability. However, the MOD-025-02 data shows that Class B was installed, leading to the use of the lower 300 MVA number. *See* Attachment 11, Appendix B.

[57] Attachments 12 and 13. *See supra* footnote 43.

[58] Attachment 2, Appendix E instructs to "[r]efer to Applicant's Application for Certification File with the California Energy Commission for further details" in reference to the "Generating Facility Information."

the permit could be a violation. Similarly, La Paloma's current and original Title V permits under the federal Clean Air Act, issued by the San Joaquin Valley Air Pollution Control District, indicate a total capacity of the plant of 1,048 MW.[59] As these permits pertain to air pollution and pollution control requirements of stationary sources, the capacity of the plant factors into the approval. Although the Underground Injection Control permit issued by the Environmental Protection Agency does not describe the capacity level specifically, the fact sheet prepared pursuant to Federal code prior to issuing the permit indicated a MW capacity of 1,022 MW.[60] Again, capacity plays an important role in the evaluation of this permit, as a greater capacity would result in larger volume of injections.

Additionally, La Paloma represented its facility as having a "nameplate capacity" of 1,022 MW in its motion for joint administration of its 2016 Chapter 11 bankruptcy cases.[61] In a bankruptcy proceeding, the value of the assets is a critical determination for the court. This value provides protection for holders of secured claims, affects the distribution to holders of unsecured claims, and impacts the ability of the petitioner to reorganize. Later in the bankruptcy proceeding, La Paloma argued against the California State Board of Equalization's assessment of the value, and included a description of the facility at 1,022 MW nameplate capacity.[62] Further, as a result of the reorganization, the new owners of the facility and party to this proceeding, CXA La Paloma, executed a Purchase and Sale Agreement ("PSA") which indicated a capacity of 1,022 MW in the appendix describing the facility.[63] This agreement was shared with the CAISO as part of the evidence of change of ownership and is included as Attachment 18.

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[59] Attachment 14.

[60] Attachment 15. *See* pg. 3, Description of Facility.

[61] Attachment 17. *See* pg. 6.

[62] Attachment 16 at P 3.

[63] The recitals to this PSA that direct readers to the appendix states the nameplate of 1,200 MW. The appendix states a nameplate capacity of 1,022 MW. *See* Attachment 18 at pg. 56.

Before the Commission, La Paloma also has made widely divergent claims about its capacity. This includes La Paloma's 2018 complaint against the CAISO regarding capacity markets where it claimed a nameplate of 1,124 MW.[64] Previously, La Paloma's complaint against the CAISO regarding a reliability must-run resource contract indicated a 965.4 MW summer rating.[65] The earliest representation of La Paloma to the Commission, the *Petition of La Paloma Generating Company, LLC for Blanket Authorizations, Certain Waivers, and an Order Approving Rate Schedule, and Request for Expedited Action*, filed in 1999, indicated a nominal rating of 1,040 MW.[66]

It was not until the negotiation of the Replacement Interconnection Agreement began—and *after* La Paloma submitted its affidavit to begin the process, which indicated the facility has a capacity of approximately 1,065 MW—that La Paloma ever represented its facility as having 1,160 MW of constructed capacity. Even now, La Paloma only asserts this is the nameplate capacity, meaning the CAISO's prescribed 1,062 MW of interconnection capacity accommodates La Paloma's actual generating output. Indeed, La Paloma's most recent submission to the CAISO's generator modeling process, submitted September of 2022, during this dispute, indicates each of the four units at the facility has an MVA rating of 300 MVA and a "Maximum Total Generating Facility Gross Output" of 255 MW, resulting in a total plant capacity of 1,020 MW.[67]

Earlier representations by La Paloma to the CAISO also include lower values for the facility. For example, the PGA La Paloma executed with the CAISO indicates the facility has four units with 255.6 MW "Designed Gross

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64 *Complaint of CXA La Paloma, LLC.* EL18-177 (filed June 20, 2018).

65 *Complaint of La Paloma Generating Company, LLC.* EL16-88 (filed June 17, 2016). Though this only describes a summer rating, it is extremely unlikely that the winter rating would be 200 MW higher.

66 *See* Docket No. ER00-107-000. Later representations in related subdockets include varied representations around 1,020 MW, with one anomaly claiming a nameplate of 1,200 MW (*Transmittal Letter for Triennial Market Power Analysis*, filed March 31, 2005).

67 Attachment 7. *See* pgs. 6, 19, 32, 45 for Units 1-4 respectively.

(Nameplate) Capacity," resulting in 1,022.4 MW total capacity.[68] This agreement is required under the CAISO tariff for generators seeking to participate in the CAISO market, and it requires the generator owner to provide information regarding the capacity and operating characteristics of each of the generating units included under the agreement.[69] This original PGA also was filed with the Commission in 2001 with the Schedule 1 indicating a capacity for each unit of 255 MW.[70] Over the years this PGA has been amended to include new operating limitations,[71] new contacts for notices, and new ownership, but the capacity has remained within 1 MW of 255 MW per unit. Further, the Master File data La Paloma submitted to the CAISO is 1,066 MW total for the facility.[72]

The requirement to provide accurate generating unit data is not just contained in the PGA; it also is contained in the CAISO tariff, which states that "[a]ll information provided to the CAISO regarding the operational and technical constraints in the Master File must be an accurate reflection of the design capabilities of the resources and its constituent equipment when operating at maximum sustainable performance over Minimum Run Time, recognizing that resource performance may degrade over time."[73] Insofar as La Paloma now claims that its Master File submissions to the CAISO were inaccurate, it is conceding a tariff violation. Both the conversion request and affidavit submitted by La Paloma and associated with this GIA conversion indicate a requested interconnection service capacity and maximum generating capability of 1,060 MW and approximately 1,065 MW.[74] Either La Paloma has provided false

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68 Attachment 3, Schedule 1.

69 Section 4.6 of the CAISO tariff. *See also* Section 4.1.2 of the Participating Generator Agreement, included as Attachment 3.

70 *See supra* footnote 44.

71 Operating limitations refer to limits such as number of start ups, minimum run time, minimum normal operations load, maximum ramp rate, maintenance restrictions, etc.

72 Attachment 8. *See* pg. 8, column "Maximum Generation Capacity."

73 Section 4.6.4 of the CAISO tariff.

74 Attachment 4 and 5.

information to the CAISO, or its claim that its facility has a capacity of 1,160 MW is false.

The Commission places great weight on the submission of accurate information to independent system operators and regional transmission organizations.[75] The CAISO was entitled to rely on previous representations made by La Paloma of the capacity of its facility in determining the capacity on the CAISO system available for generator interconnections. It would be unjust for the Commission to find now that the CAISO could not rely on such representations, particularly given the apparent disregard La Paloma has placed on reporting consistent and accurate information. Such a precedent could weaken the ability of all independent system operators and regional transmission organizations to rely on information provided by their customers and market participants.

In summary, La Paloma has long represented its capacity as substantially lower than it suddenly does in this proceeding. These prior representations are consequential because they resulted in modeling outcomes, permits issued, and values assessed. Given the CAISO tariff standard requiring the provision of accurate information, it cannot be said these multiple submission were inadvertent misrepresentations. At a minimum, these prior statements call into question the credibility of La Paloma's claim in this proceeding. The Commission should not accept La Paloma's new, unfounded claim in this proceeding given La Paloma's long history of alternative and contrary statements.

The Commission further asks:

> c. *CAISO asserts that: (1) La Paloma's Participating Generator Agreement states that the Project has 1,022.4 MW of generating capacity; (2) the Project has registered a combined generating*

[75] For example, the Commission's market behavior rules requires that "a Seller must provide accurate and factual information and not submit false or misleading information, or omit material information, in any communication with the Commission, Commission-approved market monitors, Commission-approved regional transmission organizations, Commission-approved independent system operators, or jurisdictional transmission providers, unless Seller exercises due diligence to prevent such occurrences." 18 C.F.R. § 35.41(b).

> *capacity of 1,066 MW in the CAISO master file for the Project; (3) the Project's peak output in recent years does not exceed 1,061.3 MWh in any given hour; and (4) the Project's average peak output since 2018 is 988.95 MW. Please explain why 1,062 MW was selected for the proposed Replacement Interconnection Agreement over the figures of 1,022.4 MW, 1,066 MW, 1,061.3 MW, and 988.95 MW and explain the basis upon which the capacity amount was selected.*

The CAISO utilizes a standardized approach in determining whether the electrical characteristics of a facility have changed.[76] Critical to this process is the affidavit submitted by the facility owner itself in compliance with Section 25.1.2 of the CAISO tariff. The CAISO uses this as a starting point to ensure that all parties begin with the same understanding of the capacity of the facility and expectation for the GIA. In this case, La Paloma submitted an affidavit indicating that the capacity of the facility would remain unchanged at approximately 1,065 MW.[77] The CAISO then undertakes a robust analysis to confirm this statement is accurate. The CAISO uses a uniform document called the Conversion and Repowering Checklist to conduct its due diligence to verify submitted figures. This Conversion and Repowering Checklist for La Paloma is included as Attachment 6. This process and checklist ensures the CAISO completes its due diligence in a fair and transparent manner for all generators seeking conversion or repowering.

The CAISO reviews several data points, which include those described in the Commission's question, to identify the interconnection service capacity to support the generating facility's maximum capabilities without compromising the reliability of the grid. Specifically, for a GIA conversion, the CAISO reviews (1) the customer's requested MW for the conversion (in this case, 1,060 MW initially, and then the 1,160 MW that La Paloma later claimed during negotiations); (2) the interconnection service capacity listed in the prior interconnection agreement (1,160 MW); (3) the MW of the facility in the CAISO's

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76 Pursuant to Section 25 of the CAISO tariff.

77 Attachment 5.

Transmission Planning base case (1,062 MW); (4) the MW listed in the Participating Generator Agreement (1,022.4 MW); (5) the MW listed in the Master File (1,066 MW); and (6) the peak 3-year historical MW production (1,061.3 MW). The CAISO's process identified that 1,062 MW is the maximum interconnection service capacity that captures both the historical and present capability of La Paloma's generating facility. Although the historical aggregated peak from settlements data provides an actual measured MW output capability at the point of interconnection,[78] for La Paloma, the CAISO adjusted this value to the slightly higher MW capacity in the Transmission Planning base case because it has already been included for transmission planning purposes. Also, because the transmission planning base case relies on inputs from the generator, specifically the confirmation against the generator's MOD-025 data, the base case data often provides the most accurate data about a facility's capabilities. The CAISO's conversion analysis further explains that "[b]ecause there is no indication the facility has the capability of generating more than the studied (basecase) value of 1062 MW without substantial change, a conversion value higher than 1062 MW could not be considered. However, the customer's representation [in the conversion affidavit, Attachment 5] that the facility is capable of generating 'approximately' 1065 MW supports that a 1062 MW conversion value of [sic] is accurate."[79]

The CAISO's review process does consider the interconnection service capacity included in the original GIA or original interconnection studies. However, numbers in older agreements are often unreliable because they fail to memorialize the interconnection service capacity at the point of interconnection as clearly as modern GIAs. Developers frequently built much less capacity than requested because they did not have the tools to perfectly estimate their

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[78] Three years of data is typically sufficient to demonstrate the capability of a unit or facility when it is consistently operating at a certain level measured in real time. However, the CAISO relies more heavily on test data, such as PMax testing and MOD-025 data to demonstrate the true capabilities of a unit or facility, as testing under specified conditions will be most accurate.

[79] *See* Attachment 6, page 3.

generating capacity and necessary interconnection at the time. As a result, developers often over-requested interconnection service capacity to ensure there would be enough to support the facility that was ultimately built, and the older two-party GIAs also could memorialize conflicting information. In the case of La Paloma, the original interconnection agreement includes such a conflict. Appendix E, which describes the interconnection service capacity as 1,160,000 kW (1,160 MW), also indicates that each of the four units at the generating facility has a "Nameplate Output Rating" of 255,000 @ 0.85PF kW (255 MW) and an output rating of 300,000 kVA (300 MVA).[80] This does not align with La Paloma's contentions in this proceeding, that the facility was studied and constructed with a 340 MVA rating.

(2) CAISO explains that its established practice in negotiating a Replacement Interconnection Agreement is to investigate what the generating facility's interconnection service capacity has been, including evaluating average and peak operating levels over its history, the original interconnection studies, and potentially PMax testing and site visits. Please explain whether PMax testing and site visits were conducted for the Project, and, if so, please provide supporting documentation including results, analysis, and other relevant workpapers.

The CAISO performed a PMax test on the facilities' four units separately on February 19, 2020 (Unit 1), February 20, 2020 (Unit 2), February 7, 2020 (Unit 3), and November 20, 2020 (Unit 4). Scheduling Coordinators may request PMax tests at any time. Developers and the CAISO uses them to confirm the maximum normal capability of the generating unit, as measured at the point of interconnection or point of delivery, as applicable. The results showed 267.59 MW, 266.23 MW, 266.14 MW, and 267.00 MW, for each of the four units, respectively (1066.96 MW total). Typically, a generator facility's winter rating will be slightly higher due to ambient inlet air temperature affecting the operation of the facility and the gas mix in the winter being more efficient. Because these tests were conducted during winter months, the PMax test results represent the capacity of the facility when it is most efficient. Moreover, the scheduling

80 Attachment 2.

coordinator for La Paloma, who has an incentive to maximize outcomes, requested each of these tests. In those requests, the scheduling coordinator included both the specific date and time of the test and indicated a desired testing parameter high MW range for each of the units between 265 and 267 MW. These results, as well as the underlying requests, are included as Attachment 9. Each of these tests was performed in the same year that La Paloma submitted its affidavit to effect its GIA conversion. Accordingly, the CAISO did not re-perform any of these tests as part of the conversion process, nor did La Paloma request to re-perform them.

No site visit was conducted as part of this conversion process or PMax testing. Site visits are more common at wind and solar facilities where viewers can count the number of generating units present but potentially offline for PMax tests due to outages or maintenance. The site visit thus confirms the generator owner has additional capacity that may be available. No gas-fired generator has ever requested the CAISO perform a site visit.

C. The CAISO's approach to determining base case values reflects data directly from generating facilities, in line with ratepayer interests.

To reflect the capabilities of the generating facilities interconnected to the CAISO's grid accurately, the CAISO relies on data produced by the generator owners themselves. In 2018, the CAISO established a new process for generating facility owners to submit generating facility data directly to the CAISO under the Business Practice Manual for the Transmission Planning Process ("BPM Section 10 Process").[81] Prior to the CAISO collecting data directly, the CAISO relied only on the Participating TO to correctly model the resources in the base case. The CAISO is party to a MOD-032-1 agreement with PG&E, the Participating TO for La Paloma, in which PG&E is identified as the entity responsible for correctly modeling the resources in the bases cases, but

[81] Section 10 of the CAISO's BPM for the Transmission Planning Process.

information still comes directly from the generating facilities. This process ensures that the transmission planning process reflects the actual generating capabilities of existing generators and actual grid conditions and does not overbuild the system at the expense of ratepayers. Though generating facilities may initially finance network upgrades, it is ratepayers that ultimately pay for them and reimburse the generator owners. If La Paloma now claims it constructed more generating capability than is reflected in the base case, La Paloma has not been deprived of any capacity by any other entity than itself because it has been the entity providing generating facility data.

(1) *CAISO states that its transmission planning and generator interconnection base case shows 1,062 MW of interconnection service capacity at the Project, as opposed to the 1,160 MW specified in the GIA.*

  a. *Please describe when the MW capacity of the Project in the base case first reflected a capacity of 1,062 MW.*

The CAISO's base case used for modeling transmission has never reflected a generating capacity of more than 1,062 MW for La Paloma's generating facility. The CAISO maintains base case records back to 2006. In that study cycle, and until base case prep year 2018 for study year 2020, La Paloma was modeled at 908 MW. In 2018 for study year 2020, the CAISO increased the capacity of La Paloma to 1,062 MW following the MOD-032-01 base case development process and data provided to the CAISO from PG&E. This data is meant to reflect the maximum capabilities of the facility, even if the historical average output has been lower. For this reason, in the GIA conversion process, the CAISO may raise the interconnection service capacity of a generating facility to meet the base case value, but the CAISO will never adjust the interconnection service capacity downward because of the base case. This was the case for La Paloma. La Paloma's historical peak was slightly lower than the base case capacity (approximately 1 MW), so the CAISO was able to adjust the interconnection service capacity upward to maximize that value for La Paloma without impacting grid reliability or haircutting other generators.

The CAISO initiated its BPM Section 10 Process to ensure all data included in the base case was up-to-date and accurate.[82] These submissions utilize a standard template for all generators, which includes data such as maximum generating capability and nameplate. The CAISO also confirms the data received under the BPM Section 10 Process with data submitted to the Participating TO pursuant to MOD-025-02 and to the CAISO pursuant to MOD-032. La Paloma has submitted data in this process, most recently on September 8, 2022, *i.e*., during this dispute, which indicates each of the four units at the facility has a nameplate of 300 MVA and a "Maximum Total Generating Facility Gross Output" of 255 MW. Included as the contact person on these forms is Mr. Benson, the same person whose affidavit in this proceeding claims that La Paloma has a nameplate capacity of 340 MVA at a 0.85 Power Factor. This submission is included as Attachment 7.[83]

b. Please explain when La Paloma was first informed that the Project in the transmission planning and generator interconnection base case is modeled at 1,062 MW.

As described above, the CAISO's base case information comes directly from the generating facility owners themselves. La Paloma submitted the data to the CAISO used in its transmission planning and generator interconnection base case.

(2) La Paloma maintains that the Project has a combined nameplate capacity of approximately 1,160 MW. La Paloma explains that each of the four generating units that comprise the Project is capable of an output of 289 MW. Specifically, La Paloma claims a power factor of .85 and a rated output of 340 MVA. Please provide supporting documentation for this claim, including the Project's most recent MOD-025-2 test data.

The CAISO has attached the La Paloma's most recent MOD-025-2 test data as Attachment 11. This test data was completed in November 2022. Although the document lists a nameplate MVA rating of 340 MVA (figure A1.2 for

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82 Section 10 of the CAISO's Business Practice Manual for the Transmission Planning Process. Established via Proposed Revision Request 1067 (2018).

83 *See* pgs. 6, 19, 32, 45 for generator information on Units 1-4 respectively. Mr. Benson is listed as the contact for each submission on pgs. 3, 16, 29, 42.

each generator), the supporting data does not back this assertion. In this same 2022 MOD-025-2 document, the characteristic curves included in Appendix B indicate a Class B temperature rise equipment rating, directly contradicting La Paloma's assertion that Class F equipment was installed. These characteristic curves also indicate a 300,000 kVA rating. Tables C1.3 and C1.4, Generator Under-Excited and Over-Excited Reactive Power Verification at Maximum Active Power, respectively, also show test results of between 247 and 252 MW for each unit. Interestingly, the previous MOD-025-02 test data, dated October 29, 2019 and completed by the same consultant, states that the units are rated at 300 MVA.[84] Until only recently, and now only in this single table in the most recent MOD-025-02 submission, La Paloma represented that the units at its generating facility are rated at 300 MVA. In contrast to their claims in this proceeding, in the most recent generator data submitted to the CAISO in September of 2022 to be utilized in the development of the base case, La Paloma described each of the four units at the facility as having a nameplate of 300 MVA and a "Maximum Total Generating Facility Gross Output" of 255 MW.[85]

NERC Standard MOD-025-2 requires generator owners to verify gross and net power capabilities in order to ensure that accurate information on their equipment capabilities is available for planning models used to assess reliability."[86] Though a NERC requirement, the CAISO compares these submissions with the data generator owners submit to the CAISO through its own process. Once this data is validated, the CAISO uses the final information for the generator in the base case models. For La Paloma, this was last completed utilizing their 2019 MOD-25-02 data.

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84 Attachment 10.

85 Attachment 7. *See* pgs. 6, 19, 32, 45 for Units 1-4 respectively.

86 NERC Implementation Plan available at https://www.nerc.com/pa/Stand/MOD0252DL/Project_2007-09_GV_MOD-025_Imp_Plan-clean_2012Dec05.pdf.

D. La Paloma has no right to damages.

La Paloma has failed to provide any data or documentation that would support its claim that it ever constructed a generating facility that would entitle it to damages for surplus interconnection service capacity. If the Commission were to order the Replacement Interconnection Agreement to include this excess capacity, it would trigger reliability issues. In order to resolve these, the CAISO would need to build additional network upgrades to support the retention of interconnection service capacity to which other existing generators are entitled.[87] Many other interconnection customers have effectively relied on La Paloma's submissions to the CAISO because La Paloma's own representations of its generating facility capabilities affect the base case and transmission planning. The Commission asks:

> *(3) La Paloma requests that the Commission direct CAISO and PG&E to compensate La Paloma for the 98 MW of interconnection service capacity that the Replacement Interconnection Agreement returns to CAISO and PG&E. Please explain the amount of compensation La Paloma is seeking for the reduced 98 MW of capacity, and include all workpapers, studies, or other pertinent documentation that supports any requested compensation.*

The Commission may not direct the CAISO to make payment to La Paloma. There is no remedy to obtain surplus interconnection service capacity under the conversion process described in Section 25 of the CAISO tariff. Interconnection service capacity is limited to the maximum capacity of the generating facility. Similarly, La Paloma's claim for damages must fail because calculating any such damages would be impossible without assuming that the CAISO's two-to-three party conversion process in Section 25 yielded some result other than the capacity CAISO calculated pursuant to its Commission-approved tariff. Under the terms of the Commission-approved tariff, the CAISO has no liability for administering its tariff absent intentional wrongdoing or gross

[87] As noted above, even assuming any surplus interconnection service could be justified, such surplus interconnection service is only available up to the level that can be accommodated without building new network upgrades. Order No. 845-A at P 138.

negligence, neither of which are alleged or present here.[88] Courts have held that the limitation of liability provisions in tariffs are an inherent part of the established rates and thus have the force and effect of law.[89]

III. Request for Privileged Treatment

The CAISO is submitting both a privileged version and a public version of this filing. Pursuant to 18 C.F.R. § 388.112 and the protective order adopted by the Chief Judge in this proceeding on March 16, 2022, the CAISO requests privileged treatment for certain Attachments to this filing regarding generator facility information submitted to the CAISO, as identified in the Table of Attachments. The CAISO has redacted this information from the public version of this filing. On information and belief, this information is confidential because it reflects commercial and financial information of La Paloma. The CAISO also requests CEII status for several of the privileged documents containing specific generator facility information. These documents are marked as CEII and also identified in the Table of Attachments as such.

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88 Section 14.5 of the CAISO tariff.

89 *See*, *Tesoro Ref. & Mktg. Co. LLC v. Pac. Gas & Elec. Co.,* 146 F. Supp. 3d 1170, 1182 (N.D. Cal. 2015).

IV. Communications

In accordance with Rule 203(b)(3) of the Commission's Rules of Practice and Procedure, the CAISO respectfully requests that service of all pleadings, documents, and all communications regarding this proceeding be addressed to these individuals:

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V. Conclusion

La Paloma never constructed a facility near the capacity value it now claims. La Paloma's claims contradict all previous representations and data regarding the units and the results of unit testing and actual operations. The CAISO's GIA conversion process is spelled out in the tariff and relies only on the operational and electrical characteristics of the constructed facility. The CAISO has properly followed its tariff and applicable Commission precedent in determining the interconnection service capacity in the Replacement Interconnection Agreement. La Paloma is not entitled to any more interconnection service capacity than 1,062 MW. For these reasons, the CAISO requests the Commission accept the Replacement Interconnection Agreement with this interconnection service capacity value.

/s/ Sarah E. Kozal
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Anthony Ivancovich
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Counsel for the California Independent
System Operator

Dated: February 13, 2023

Attachment 1 – Table of Attachments

Initial Brief of the

California Independent System Operator Corporation

PG&E – La Paloma Unexecuted LGIA

ER21-2592

February 13, 2023

Attachment 1: Table of Attachments

#	Documents	Classification
1	Table of Attachments	Public
2	Original GIA	Public
3	Participating Generator Agreement	Privileged
4	GIA Conversion Interconnection Request	CEII
5	GIA Conversion Affidavit	Privileged
6	GIA Conversion and Repowering Checklist	CEII
7	La Paloma BPM Section 10 Submissions	CEII
8	Master File Data	CEII
9	2020 PMax Requests and Results	CEII
10	2019 Mod-025 Data	CEII
11	2022 Mod-025 Data	CEII
12	La Paloma Application to Construct Submission to California Energy Commission: Excerpted Executive Summary. Complete document not currently available online but may be obtained from the CEC.	Public
13	California Energy Commission Application to Construct Commission Decision: Excerpted Section I and Section V. Complete document available at https://efiling.energy.ca.gov/GetDocument.aspx?tn=35900&DocumentContentId=66565.	Public
14	Title V Permit (2017): Excerpted Detailed Summary of Facility Permits Complete document available at http://www.valleyair.org/notices/Docs/2017/11-06-17_(S-1162576)/S-1162576.pdf	Public
15	Environmental Protection Agency Injection Control Permit Fact Sheet	Public
16	Motion for Joint Administration in 2018 Bankruptcy Proceeding	Public
17	La Paloma Bankruptcy Pre-Trial Brief	Public
18	Purchase and Sale Agreement	Privileged

Attachment 2 – Original GIA

Initial Brief of the

California Independent System Operator Corporation

PG&E – La Paloma Unexecuted LGIA

ER21-2592

February 13, 2023

Pacific Gas and Electric Company

WE DELIVER ENERGY.

Generator Interconnection Agreement

This Agreement provides for the interconnection and parallel operations of nonutility-owned generation connected to the PG&E Electric System at either transmission (60 kV and above) or distribution (below 60 kV) voltage and applies only to those Generating Facilities that are, or intend to become, a *Participating Generator* pursuant to the ISO Tariff.

1 PREAMBLE

THIS AGREEMENT, between **La Paloma Generating Company, LLC, as agent for La Paloma Generating Trust, Ltd.** (Applicant) and PACIFIC GAS AND ELECTRIC COMPANY (PG&E), hereinafter sometime referred to individually as "Party" or collectively as "Parties", is as follows:

2 RECITALS

2.1 Whereas, PG&E is a public utility engaged, among other things, in the business of owning and operating an electric system consisting of transmission and distribution facilities in Northern California;

2.2 Whereas, Applicant has (i) purchased or intends to purchase a Generating Facility from PG&E; or (ii) owns a Generating Facility that sells or sold power to PG&E under a Power Purchase Agreement and intends to convert or has converted the status of such Generating Facility to sell all such power on the wholesale market; or (iii) has constructed or intends to construct, a new or expanded Generating Facility. Applicant intends to operate the Generating Facility, which is described in Appendix E, for the purpose of selling electric power at wholesale and has requested permission from PG&E to interconnect such Generating Facility in order to operate it in parallel with the PG&E Electric System;

2.3 Whereas, Applicant intends to become a *Participating Generator* pursuant to the requirements of the ISO Tariff;

2.4 Whereas, PG&E is willing to permit such interconnection and parallel operation under the terms and conditions contained in this Agreement;

2.5 Whereas, Applicant understands that this Agreement does not provide any transmission service, distribution service, or *Ancillary Services* as such services, if necessary, will be provided under separate arrangements with PG&E, the ISO, or Third Parties;

2.6 Whereas, this Agreement obligates Applicants to design new Generating Facilities or additions to existing Generating Facilities consistent with *Good Utility Practice*;

2.7 Whereas, this Agreement obligates Applicant to operate and maintain its Generating Facility consistent with *Good Utility Practice*;

2.8 Whereas, this Agreement establishes interconnection and operating responsibilities and associated procedures for communications between Applicant and PG&E Electric System operators. The Agreement also establishes procedures for safe work practices on the PG&E Electric System and routine test procedures;

2.9 Whereas Applicant understands that it will be subject to the ISO Tariff and protocols and operating procedures thereunder and that it is responsible for making any arrangements necessary with the ISO.

3 AGREEMENT

Now, therefore, in consideration of the mutual covenants herein set forth, the Parties agree as follows:

4 DEFINITIONS

The following terms, when used in this Agreement with the initial letters capitalized, whether in the singular, plural or possessive, shall have the meanings indicated below. Italicized terms, when used in this Agreement, including these definitions, shall have the meanings as defined in the currently effective Master Definitions Supplement to the ISO Tariff.

4.1 Agreement

This Generator Interconnection Agreement between PG&E and Applicant and its Appendices, as it may be amended.

4.2 Clearance Point

The point(s) that electrically isolate PG&E's equipment from possible sources of energy from the Generating Facility. Clearance Points may be requested by PG&E from time to time as provided in Section 7.7, so that work can be safely performed on the PG&E Electric System. The Clearance Point is normally located at the Disconnect Device.

4.3 Cost

All just, reasonable, necessary and prudent expenses or capital expenditures associated with PG&E's transmission and interconnection facilities, including operation, maintenance, engineering study, adverse impact identification, adverse impact mitigation, contract modification, administrative and general expenses, taxes, depreciation, and costs of capital as determined in accordance with the FERC Uniform System of Accounts as such may be amended or superseded from time to time. The appropriate components of the Cost, as defined herein, shall be applied for the particular transaction performed.

4.4 CPUC

The California Public Utilities Commission or its successor.

4.5 Designated PG&E Switching Center

The PG&E location, identified in Section 8.1 of this Agreement, with operational jurisdiction over the Generating Facility.

4.6 Disconnect Device

A device used to isolate the Generating Facility from the PG&E Electric System and normally located adjacent to the Point of Interconnection. Each Generating Facility must have a Disconnect Device which shall be clearly marked "GENERATOR DISCONNECT SWITCH".[1]

[1] The Disconnect Device for the La Paloma generation project are the two 230 kV circuit breakers connecting the La Paloma generation tie-lines to the 230 kV bus at Midway Substation.

4.7 [Intentionally omitted]

4.8 Electric Standard Operating Instructions

The standard operating orders adopted and published by PG&E under the title "Electric Standard Operating Instructions" which all PG&E personnel involved in the operation, construction and maintenance of the PG&E Electric System are required to follow, as they may be modified or superseded from time to time.

4.9 Emergency

An abnormal condition or situation that adversely affects, or potentially may adversely affect, the PG&E Electric System Integrity. Such an event may result from, but is not limited to, a *System Emergency*.

4.10 FPA

The Federal Power Act as it may be amended or superseded.

4.11 FERC

The Federal Energy Regulatory Commission or its regulatory successor.

4.12 Force Majeure

Any occurrence beyond the reasonable control of and without the fault or negligence of the Party claiming Force Majeure which causes the Party to be unable to perform part or all of its obligations, which by exercise of due foresight such Party could not reasonably have been expected to avoid and which the Party is unable to overcome by the exercise of due diligence. Such an occurrence may include, but is not limited to, act of God, labor disputes, sudden actions of the elements, actions or inactions by federal, state, or municipal agencies, and actions or inactions of legislative, judicial, or regulatory agencies of competent jurisdiction. Nothing contained herein shall be construed to require any Party claiming Force Majeure to settle any labor dispute.

4.13 Generating Facility

The *Generating Unit* described in Appendix E and associated facilities.

4.14 Generator Special Facilities Agreement

A separate agreement between PG&E and Applicant, specifying facilities, owned by PG&E, that PG&E determines are necessary for Applicant's Generation Facility to interconnect with PG&E and allow the Generating Facility to deliver power up to the Interconnection Capacity into the PG&E Electric System. For new projects, the Generator Special Facilities Agreement also includes certain project milestones that must be met before this Agreement can be executed. PG&E shall have the right to terminate this Agreement in the event that the Generator Special Facilities Agreement terminates pursuant to the terms and conditions of the Generator Special Facilities Agreement.

4.15 Governmental Authority

Any federal, state, local or other governmental, regulatory or administrative agency, governmental commission, department, board, subdivision, court, tribunal, or other governmental arbitrator, arbitral body or other authority, but excluding Applicant and any subsequent owner of the Generating Facility (if Applicant or any subsequent owner is otherwise a Governmental Authority under this definition).

4.16 Interconnection Capacity

The contractual electric capacity in kW at the Point of Interconnection up to which the

Generating Facility may deliver electrical power into the PG&E Electric System. The Interconnection Capacity for both new and existing projects is specified in Appendix E.2.2.

4.17 Interconnection Facilities

All means required, and apparatus installed as determined by PG&E, to safely interconnect a Generating Facility, or an Applicant-owned generation tie line with the PG&E Electric System. Interconnection Facilities may include, but are not limited to, the Disconnect Device, connection, step-up transformers and related equipment, switching, metering, and communications equipment, as well as any necessary additions, modifications and reinforcements to the PG&E Electric System at the Point of Interconnection necessitated as a result of interconnecting the Generating Facility to the PG&E Electric System. Interconnection Facilities also include control and safety equipment to protect (i) the PG&E Electric System and its customers from faults occurring at the Generating Facility; and (ii) the Generating Facility from faults occurring on the PG&E Electric System or on the electric system of others to which the PG&E Electric System is directly or indirectly connected.

4.18 Interconnection Service

The term "Interconnection Service" as used in this Agreement shall not refer to any right to transmit power over PG&E's transmission and/or distribution system. Instead, Interconnection Service refers to the Applicant's ability to deliver power into the PG&E Electric System at the Point of Interconnection under the terms and conditions of this Agreement when the Generating Facility is interconnected with the PG&E Electric System, subject to section 6.4.

4.19 ISO

The California Independent System Operator Corporation or its successor which operates the *ISO Control Area*.

4.20 ISO Tariff

The currently effective ISO Agreement and Tariff, dated March 31, 1998, as approved by FERC and as it may be modified or superseded from time to time.

4.21 Non-Test

A procedure used by PG&E in connection with work on a live electric line or near an energized circuit. In a Non-Test, PG&E will request that Applicant contact the Designated PG&E Switching Center before re-energizing a circuit following an automatic trip.

4.22 Person

An individual, partnership, joint venture, corporation, limited liability company, trust, association or unincorporated organization, or any Governmental Authority.

4.23 PG&E Electric System

All properties and other assets, now or hereafter existing, which are owned or controlled by PG&E or its successor(s), and used for or directly associated with the generation, transmission, transformation, distribution or sale of electric power, including all additions, extensions, expansions, and improvements thereto, but excluding the properties and assets of subsidiaries of PG&E.

4.24 PG&E Electric System Integrity

The state of operation of the PG&E Electric System in a manner that is deemed by PG&E in its sole discretion necessary or desirable to minimize the risk of injury to persons and/or property and enable PG&E to provide adequate and reliable electric service to its customers.

4.25 PG&E Interconnection Handbook

A handbook, developed by PG&E pursuant to TCA Section 10.3.1, describing technical requirements for wholesale generators and loads connected to the PG&E Electric System, as it may be modified or superseded from time to time. PG&E's standards contained in the handbook shall be consistent with *Good Utility Practice* and *Applicable Reliability Criteria*. Where there is conflict or inconsistency with the terms in this Agreement and the PG&E Interconnection Handbook, the terms in this Agreement shall apply.

4.26 PG&E Wholesale Distribution Tariff

The PG&E Wholesale Distribution Tariff, effective March 31, 1998, as it may be modified or superseded from time to time. The PG&E Wholesale Distribution Tariff applies to Generating Facilities connected to the PG&E Electric System at distribution voltages.

4.27 Point of Interconnection

The point where the electrical conductors from the Generating Facility contact the PG&E Electric System.[2] Generally, a Generating Facility will have a single Point of Interconnection.

4.28 Reliability Management System Agreement

The Reliability Management System (RMS) Agreement between the WSCC and PG&E, executed on June 18, 1999, that requires PG&E to include the terms and conditions of Appendix A of the RMS Agreement in any new interconnection agreement. Appendix A of the RMS Agreement is included as Appendix G of this Agreement.

4.29 Responsible Meter Party

The Party having the responsibility for providing, installing, owning, operating, testing, servicing and maintaining meters and associated recording or telemetering equipment at each Point of Interconnection. Currently the Responsible Meter Party is Applicant for transmission interconnections and PG&E for distribution interconnections.

4.30 Significant Regulatory Change

A Significant Regulatory Change occurs when the FERC, the CPUC, the California Energy Commission, the California Legislature, or the United States Congress issues an order or decision or adopts or modifies a tariff, or enacts a law that: (i) significantly and substantially changes the structure or function of the California electric utility industry in a way that affects this Agreement; or (ii) substantially prevents either Party from performing its functions under this Agreement.

4.31 TCA

The Transmission Control Agreement, between the ISO and *Participating TOs* establishing the terms and conditions under which each *Participating TO* will discharge its respective duties and responsibilities, as may be modified from time to time. PG&E is a *Participating TO* and has entered into a TCA with the ISO.

4.32 Third Party

A Person other than PG&E or Applicant.

4.33 WSCC

The Western Systems Coordinating Council or its successor.

[2] The Point of Interconnection for the La Paloma generation project is at the line-side disconnect switches for the two 230 kV circuit breakers which connect the La Paloma generator tie-lines to the 230 kV bus at Midway Substation.

5 TERM AND TERMINATION

5.1 Term

The Parties shall be bound by the terms of this Agreement upon its execution by both Parties. This Agreement shall be in effect on the latest of the date on which Applicant operates its Generating Facility in parallel with PG&E or the date on which FERC accepts this Agreement for filing and permits it to be placed into effect without material change or material new condition unacceptable to either Party. When it becomes effective, this Agreement will remain in effect for an initial term of twenty (20) years from the date of its completed execution.

5.1.1 Successor Agreement

At the request of either Party, the Parties shall, provided, this Agreement has not otherwise already terminated, meet no later than one (1) year prior to the expected expiration of this Agreement to discuss renewal of this Agreement or to negotiate a reasonable successor agreement; provided, that nothing herein commits either Party to enter into any renewal or successor agreement.

5.2 Termination

5.2.1 PG&E shall have the right to terminate this Agreement pursuant to Sections, 6.3.1, 15.3, and 15.9. In addition, PG&E shall have the right to terminate this Agreement in the event that the Generator Special Facilities Agreement, if one is required, terminates pursuant to the terms and conditions of the Generator Special Facilities Agreement. Nothing in this section shall be deemed to limit PG&E's right to make changes pursuant to section 15.23.1.

5.2.2 Upon termination of this Agreement, all rights Applicant shall have under this Agreement for the Generation Facility to be interconnected to the PG&E Electric System shall cease and Applicant shall claim no further right to have the Generating Facility connected to the PG&E Electric System by reason of this Agreement. The provisions of this Section 5.2.2 however shall not be construed as a bar to assertion by Applicant of any rights it may have apart from this Agreement to remain interconnected with PG&E following termination of this Agreement, pursuant to any applicable law or regulation, independent and exclusive of this Agreement.

6 PG&E'S RIGHTS AND OBLIGATIONS

6.1 Limited Responsibility to Accept Energy Into the PG&E Electric System

6.1.1 The intent and purpose of this Agreement is to provide only for the interconnection and parallel operation of the Generating Facility with the PG&E Electric System, including the establishment of the Interconnection Capacity and rules governing the interconnected operations in order to promote safety and reliability.

6.1.2 PG&E shall accept into the PG&E Electric System at the Point of Interconnection electric energy produced by the Generating Facility up to the Interconnection Capacity specified in Appendix E.2.2 and delivered to PG&E in accordance with this Agreement; provided, that separate arrangements must be made for the transmission service needed to transfer that energy from the Point of Interconnection to where it is to be delivered.

6.1.3 Nothing in this Agreement shall be deemed either expressly or implied to obligate PG&E to provide or make available any electric transmission or distribution service for the transport of electric energy from the Generating Facility.

6.1.4 Applicant understands that PG&E is subject to the ISO Tariff and to the TCA which it has entered into with the ISO and, as a result, cannot commit to provide any new transmission services without the approval of the ISO.

6.1.5 Long Term Shutdown

In the event that the Generating Facility is shut down, or partially shutdown, for a period of six (6) months or more for any reason, the Parties, at either Party's request, shall meet to determine on what date ("Restoration Date") the Generating Facility may reasonably be expected to resume full power production if Applicant uses due diligence in curing whatever problems exist. If the Parties cannot agree on such a Restoration Date, the Restoration Date, at either Party's request, shall be determined by dispute resolution pursuant to Section 15.10. Applicant must obtain PG&E's approval pursuant to Section 7.3 prior to resuming normal operations.

6.1.5.1 Right to Reduce Interconnection Capacity

If the Restoration Date, determined by either mutual agreement or dispute resolution pursuant to Section 6.1.5, is greater than eighteen (18) months from the date the Generating Facility is initially shut down or partially shutdown or if the Restoration Date is less than eighteen (18) months but restoration has not occurred within the eighteen (18) month period, PG&E shall have the right to reduce the Interconnection Capacity to a capacity value that reflects the then-current generating capability of the Generating Facility. However if Applicant is making commercially reasonable efforts to resume full power production as quickly as possible, PG&E shall waive its right to reduce the Interconnection Capacity under this Section 6.1.5.1. Following a reduction of Interconnection Capacity, any subsequent increase of Interconnection Capacity shall be established pursuant to Section 6.7.

6.2 No Facility Preservation Obligation After Termination

After termination of this Agreement, PG&E shall have no obligation under this Agreement to remain interconnected with Applicant's Generating Facility. Any subsequent reconnection of the Generating Facility to the PG&E Electric System shall be governed by the laws and regulations governing electric utility interconnection at that time.

6.3 Right to Disconnect the Generating Facility

6.3.1 Applicant's Failure to Meet Standards

PG&E may disconnect the Generating Facility from the PG&E Electric System if the Generating Facility fails to meet the requirements set forth in this Agreement. Except as described in Section 6.3.1.1, prior to such disconnection PG&E shall provide written notice to Applicant detailing Applicant's failure to adhere to such requirements and provide Applicant thirty (30) calendar days to correct such deficiency. PG&E shall not disconnect the Generation Facility if Applicant corrects the deficiencies described in the written notice within thirty (30) calendar days. PG&E reserves the right to terminate this Agreement if PG&E disconnects the Generating Facility under this Section 6.3.

6.3.1.1 Immediate Disconnection

PG&E reserves the right to immediately disconnect the Generating Facility if such deficiencies, as determined by PG&E or the ISO, could be expected to have a material adverse affect on the PG&E Electric System Integrity, endanger the health or safety of the public or any PG&E employee, or cause material damage to the PG&E Electric System.

6.3.2 Right to Inspect Applicant's Facilities

PG&E shall have the right to enter Applicant's premises at any reasonable times for inspection of Applicant's operations logs and control, protective and safety devices; provided, PG&E gives Applicant reasonable notice prior to commencing such an inspection. Upon receiving notice of an inspection from PG&E, Applicant shall provide PG&E with Applicant's written safety, security and operating conventions, protocols and practices. While on Applicant's premises, PG&E shall comply with Applicant's written safety, security and operating conventions, protocols and practices in force on the date of the inspection; provided, that Applicant has provided PG&E with such written safety, security and operating conventions, protocols and practices. If PG&E determines that a hazardous condition exists and immediate action is necessary to protect persons, PG&E's facilities or other customers' facilities from damage or interference caused by the Generating Facility, then PG&E may immediately disconnect the Generating Facility from the PG&E Electric System.

6.4 Right to Interrupt Interconnection Service

6.4.1 Unscheduled Interruptions

PG&E may temporarily interrupt or reduce Interconnection Service to the Generating Facility, or temporarily separate the PG&E Electric System from the Generating Facility, if PG&E determines at any time that: (i) an Emergency condition exists; or (ii) the action is necessary or desirable to prevent a hazard to life or property; or (iii) the operation of the PG&E Electric System is suspended, interrupted or interfered with as a result of Force Majeure; or (iv) at the instruction of the ISO in accordance with the TCA. In the event of such interruption or reduction in Interconnection Service, PG&E shall restore full Interconnection Service on a basis comparable to the restoration of other public service and safety facilities, and, in any event, as directed by the authorized emergency response officials. Should PG&E determine that such interruption or reduction in service will be of a prolonged nature, the PG&E and Applicant shall confer and attempt to agree on the time by which full service can be restored.

6.4.2 Interruption by Protective Devices

PG&E utilizes automatic protective devices in order to assist in maintaining the integrity and reliability of the PG&E Electric System and to protect its customers from damage, injury or prolonged outages. Interconnection Service on the PG&E Electric System is subject to interruption in the event of operation of such devices. In the event of such interruption, Interconnection Service will be restored consistent with *Good Utility Practice*.

6.4.3 Maintenance Interruptions

6.4.3.1 PG&E may interrupt Interconnection Service to the Generating Facility to perform necessary maintenance or other modifications on the PG&E Electric System; provided, that such interruptions are consistent with *Good Utility Practice*. PG&E shall coordinate such interruptions with Applicant and shall provide Applicant with as much advance notice as possible but in no event shall the notice be less than three (3) *Business Days* except where PG&E determines an Emergency exists or may exist which requires quicker action to correct.

6.4.3.2 PG&E normally limits such interruptions to business hours on a *Business Day*, between 8:00 AM and 5:00 PM. In the event that Applicant desires the interruption to occur during non-business hours, PG&E reserves the right to charge Applicant the additional Cost for work performed. PG&E will provide Applicant with an estimate of the additional Cost and if Applicant still desires the work to be performed during non-normal business hours and PG&E does perform the work, PG&E shall charge Applicant the actual additional Costs of the work, the amount of which shall not exceed the cost estimate.

6.5 Right to Install Special Facilities

In the event it is necessary, consistent with *Good Utility Practice*, for PG&E to install any PG&E-owned facilities in order to accommodate an increase in the Interconnection Capacity, the Parties shall work together, in good faith, to agree upon the extent and Costs of such facilities. If the Parties cannot agree on the need or Cost of such facilities, then the dispute shall be resolved through procedures set forth in Section 15.10; provided, that in the event that PG&E deems it necessary to begin construction of the facilities prior to the resolution of a dispute, PG&E shall have the right to develop a new or amended Generator Special Facility Agreement and file such new or amended agreement unilaterally with the FERC pursuant to Section 15.23. Each new or amended Generator Special Facility Agreement shall specify that the Applicant pay PG&E the Costs of such facilities and that PG&E has no obligation to begin construction prior to receipt of such payments.

6.6 Provision Applicable if PG&E and Applicant are Affiliates

In the event that PG&E and Applicant are affiliates within the scope and terms of FERC Orders No. 888, 888-A, 889, and 889-A, and regulations thereunder as they may be amended or superseded, notwithstanding anything to the contrary contained in this Section 6 or otherwise in this Agreement, PG&E shall not provide Applicant access to any information about PG&E's transmission system that is not available to PG&E's open access transmission customers, nor shall PG&E provide Applicant any wholesale market information via any shared telecommunications equipment or services.

6.7 Establishing Interconnection Capacity

For existing projects, the Interconnection Capacity is normally set equal to the maximum kW output of the Generating Facility. For new projects or increases in existing projects, the Interconnection Capacity is established through technical studies conducted by PG&E pursuant to ISO Tariff Section 5.7.1. In cases where multiple Generating Facilities are connected to a non PG&E-owned generation tie line that is connected to the PG&E Electric System, a separate Interconnection Capacity is established for each Generating Facility. Interconnection Capacity shall be specified in Appendix E.2.2.

7 APPLICANT'S RIGHTS AND OBLIGATIONS

7.1 Applicant's Right to Deliver Power to the PG&E Electric System

Applicant shall have the right to deliver power from the Generating Facility into the PG&E Electric System; provided, at no time shall Applicant deliver power at a rate that exceeds the Interconnection Capacity specified in Appendix E; nor shall Applicant deliver power into the PG&E Electric System unless it has arranged for transmission service pursuant to Section 6.1.2.

7.1.1 Consequences of Exceeding Interconnection Capacity

It is the intent of the Parties that power deliveries to the PG&E Electric System shall not exceed the Interconnection Capacity specified in Appendix E at any time. In the event that power deliveries exceed the Interconnection Capacity, the Parties, at either Party's request, shall meet to determine the reason that the Interconnection Capacity was exceeded. If the Parties determine that such an event was not due to Force Majeure or an Emergency and is reasonably likely to occur again in the future then a new Interconnection Capacity shall be established. PG&E shall have the right to require that a study be conducted pursuant to Section 6.7, at Applicant's expense, to determine if additional facilities, including upgrades to the PG&E transmission system, are required to accommodate the increased Interconnection Capacity. If the Parties fail to agree, within thirty (30) calendar days after the initial meeting, that the Interconnection Capacity must be increased, the matter, at either Party's request, shall be resolved through the dispute resolution procedures set forth in Section 15.10. If PG&E determines that additional facilities are required, then the Parties shall work together, in good faith, to develop a Generator Special Facilities Agreement as described in Section 6.5.

7.2 Generator Must Meet Standards

7.2.1 Generating Facility to Meet Applicable Laws and *Good Utility Practice*

Applicant shall be fully responsible for designing new Generating Facilities or additions to existing Generating Facilities in accordance with *Good Utility Practice*. Applicant is also fully responsible for installing, owning, operating and maintaining the Generating Facility in accordance with all applicable laws, rules and regulations of governmental agencies having jurisdiction and in accordance with *Good Utility Practice*.

7.2.2 Generating Facility to Meet Requirements of the PG&E Interconnection Handbook

New Generating Facilities or additions to existing Generating Facilities shall be designed and constructed in accordance with the PG&E Interconnection Handbook. The Generating Facility shall be operated and maintained in accordance with the PG&E Interconnection Handbook except as provided in Section 7.2.2.1 and Appendix F. Applicant shall be responsible for assuring that its operating personnel at all times have the latest version of said handbook.

7.2.2.1 Exceptions for Existing Projects

For existing projects that are already interconnected and operating in parallel with the PG&E Electric System, PG&E may waive, in its sole discretion, specific requirements of the PG&E Interconnection Handbook; provided, that PG&E, (i) shall not waive any requirements where in PG&E's judgment such waiver (a) would be inconsistent with *Good Utility Practice* or (b) could reduce the ability of the Generating Facility to operate safely, (ii) shall apply such waiver on a non-discriminatory basis for all such existing projects, and (iii) shall specify what requirements have been waived in Appendix F. In the event that such a waiver results, or might result, in PG&E's sole judgment, in an Emergency, a degradation of the PG&E Electric System Integrity, a system disturbance, or any other such event, PG&E shall have the right to rescind such waiver and require the Generating Facility to meet at Applicant's expense and within a reasonable amount of time the then-current requirements of the PG&E Interconnection Handbook. At either Party's request, disputes under this Section 7.2.2.1 shall be resolved through dispute resolution proceedings pursuant to Section 15.10.

7.2.3 Applicant Shall Provide Transmission Planning Data

Applicant is obligated to provide PG&E with steady state and dynamic data for the Generating Facility as required by the PG&E Interconnection Handbook and the WSCC.

7.2.4 Applicant Shall Operate Protective Devices

Applicant shall operate protective and safety devices as required by Section 7.2.2 for safe parallel operation of the Generating Facility with the PG&E Electric System.

7.2.5 Duty to Minimize Disturbances

Applicant agrees to plan and operate its Generating Facility in order to minimize electrical disturbances on the PG&E Electric System caused by the operation of Applicant's Generating Facility.

7.2.6 Power Delivery Standard

Power delivered to the PG&E Electric System from the Generating Facility shall be at what is commonly designated as three phase alternating current, at 60 Hertz, and at the normal voltage specified in Appendix E. Normal variations in voltage and frequency shall be permitted pursuant to *Good Utility Practice*.

7.3 No Parallel Operation Without Approval

For new Generating Facilities or for existing Generating Facilities that have shut down pursuant to Section 6.1.5, Applicant shall not operate its Generating Facility in parallel with the PG&E Electric System until the Generating Facility has been inspected by an authorized PG&E representative and final written approval has been received from PG&E, which approval shall not be unreasonably withheld or delayed. Any such inspection and approval shall not be deemed or construed as any representation, assurance, guarantee or warranty by PG&E of the safety, durability, reliability, or compliance as required in Section 7.2, of the Generating Facility and its control, protective and safety devices or the quality of power produced by the Generating Facility.

7.4 Applicant Must Implement Operating Guidelines

Applicant shall implement the operating guidelines contained in this Agreement, including applicable guidelines included in the PG&E Interconnection Handbook. Applicant shall ensure that its operating personnel are familiar with the procedures and guidelines contained in or incorporated by reference into this Agreement.

7.5 Obligation to Maintain Power Factor

Applicant understands that the voltage of PG&E's electric transmission system is not automatically regulated and may vary widely. The voltage levels will fluctuate depending on operation and PG&E Electric System conditions. In accordance with the PG&E Interconnection Handbook, Applicant shall install, operate, and maintain the necessary equipment to maintain proper power factor and voltage at the Point of Interconnection. All voltage regulation equipment shall be operated in an automatic mode being immediately responsive to changes in voltage.

7.6 Emergency Disconnection

In an Emergency, Applicant agrees to expeditiously open the Disconnect Device[3] upon notification from the Designated PG&E Switching Center.

7.7 Clearance Point Request by PG&E

Applicant must open its Disconnect Device[4] if PG&E requests a Clearance Point. A qualified PG&E employee will observe that the Disconnect Device is open, lock it with a PG&E lock, and attach a filled-out "Man-on-Line" tag to indicate it is a Clearance Point.

7.8 Routine Tests and Non-Tests

When conducting a test or a Non-Test, Applicant agrees to follow the procedures described in Appendix B.

7.9 Obligation to Maintain Insurance

Applicant agrees to acquire and continuously maintain during the term of this Agreement insurance coverage which meets the requirements of Appendix A.

8 OPERATING COMMUNICATIONS AND NOTIFICATIONS

8.1 Designated Representatives

The Parties shall provide for operating communications through their respective designated representatives as follows:

Clifford Thompson PG&E	Shift Supervisor La Paloma Generating Plant Applicant
Operations Supervisor Title	Shift Supervisor Name or Title of Operator
Midway Substation Designated PG&E Switching Center	(661) 762-9457 Telephone Number
661-398-5790 Telephone Number	Operations Manager Alternate Operator
	(661) 762-9457 Telephone Number

[3] PG&E controls the 230 kV circuit breakers which are the Disconnect Device for the La Paloma generation project.
[4] See footnote 3.

8.2 Communication with the Designated PG&E Switching Center

8.2.1 Applicant shall maintain operating communications with the Designated PG&E Switching Center. The operating communications shall include, but not be limited to, advising the Designated PG&E Switching Center promptly, and in advance if possible, of any paralleling with or separation from the PG&E Electric System and any scheduled and unscheduled shutdowns, equipment clearances, and changes in levels of operating voltage or power factors. Such communications shall also include daily operating reports as provided below in Section 9.

8.2.2 Applicant promptly shall notify the Designated PG&E Switching Center of, and any changes in, the following:

(a) The current names and 24-hour phone numbers of the personnel responsible for operating and maintaining the Generating Facility.

(b) Any Emergency situation or any request that PG&E de-energize a portion of the PG&E Electric System under its control.

(c) Any changes in the mechanical or electric condition of the Generating Facility or Interconnection Facilities that may affect the reliability of either the Generating Facility or the PG&E Electric System.

(d) Immediately upon discovery, any misoperation or inoperable condition of a PG&E-required interconnection relay or circuit breaker.

(e) Immediately upon discovery, the operation of any circuit breaker that has operated by a PG&E-required interconnection relay, along with the relay targets that caused the circuit breaker to operate.

(f) Plans to manually parallel with or separate from the PG&E Electric System and the times of actual manual parallels and separations. Emergency separations shall be reported as soon as conditions permit.

8.3 Oral Communications

All oral operating communications shall be conducted through the Designated PG&E Switching Center. Applicant agrees to maintain 24 hour direct phone service so that PG&E can give instructions to Applicant or its designated operator.

8.4 Telemetering Requirements

For Generating Facilities 10,000 kW and greater, Applicant must telemeter real-time information pursuant to the requirements of the PG&E Interconnection Handbook; provided that, if such telemetered information is reasonably available to PG&E from the ISO, Applicant shall be relieved of its obligation to provide telemetered information directly to PG&E. When telemetered real-time information is required for PG&E to bill Applicant for service taken under separate PG&E tariffs, upon PG&E's request, Applicant shall request the ISO to provide PG&E with read-only passwords and other information necessary for PG&E to access Applicant's meters.

8.5 Operating Agreements

The Parties may enter into a separate agreement describing specific operating procedures regarding the Generator Facility.

9 OPERATION AND MAINTENANCE OF GENERATING FACILITY AND GENERATOR STEPUP FACILITIES

9.1 Daily Operating Log

Applicant shall keep a written daily operations log for the Generating Facility. The log shall include information on unit availability, maintenance outages, circuit breaker trip operations, and any significant events related to operations of the Generating Facility.

9.2 Power Factor and Voltage Instructions

Applicant will receive, from time to time, output voltage or power factor instructions from the Designated PG&E Switching Center or the ISO. Applicant shall operate the Generating Facility to maintain the specified output voltage or power factor at the Point of Interconnection. If Applicant is unable to maintain the specified voltage or power factor, it shall promptly notify the Designated PG&E Switching Center.

9.3 Daily Operating Report for Small Generators (1000 kW to 10,000 kW)

Applicant shall telephone a daily operating report to the Designated PG&E Switching Center at least once each day, or as otherwise agreed to by the Parties. The report shall include information on hourly unit capacity, unit availability, maintenance outages, circuit breaker trip operations, hourly energy schedules, and any significant events related to operations of the Generating Facility. The parties may mutually agree to transmit such daily information using electronic mail.

9.4 Daily Operating Report for Large Generators (Greater than 10,000 kW)

If the Generating Facility is capable of delivering more than 10,000 kW, the information required by Section 9.3 shall be telemetered to the Designated PG&E Switching Center; provided that, Applicant shall telephone such information to the Designated PG&E Switching Center upon receiving notice that telemetered data is not being correctly received by PG&E.

9.5 Unattended Operation

If the Generating Facility is unattended and has the capability for automatic or remotely-initiated paralleling, it is not necessary to notify the Designated PG&E Switching Center before paralleling with the PG&E Electric System. However, such Generating Facility must report relay targets within 72 hours following automatic separation, or immediately upon request of the Designated PG&E Switching Center. All unattended facilities must be equipped with an event recorder as described in the PG&E Interconnection Handbook.

9.6 Maintenance Notice

Under normal conditions, Applicant shall give as much advance notice as possible (a minimum of three (3) *Business Days*) to the Designated PG&E Switching Center when planning to perform work that may affect the PG&E Electric System. At a minimum, the notice shall include:

(a) Nature of the work to be performed.

(b) Date and time the work will begin.

(c) Date and time the work will be completed.

(d) Apparatus to be cleared and the Clearance Points required.

(e) Name and telephone number of the person in charge of the work.

(f) Whether or not protective grounds will be installed.

9.7 Maintenance on Facilities Energized by PG&E

9.7.1 If Applicant wishes to perform work on its own facilities which would normally be energized by PG&E-controlled source(s) of energy, Applicant may request that PG&E open, lock and tag PG&E's associated disconnect device to isolate Applicant's facilities from PG&E source(s) of energy. PG&E will also establish the disconnect device(s) as an open Clearance Point(s) and install "Man-on-Line" tags (see GTS Standard S0403).

9.7.2 PG&E is not responsible for Applicant's equipment energized by the generator step-up transformer or by any other means. Applicant agrees that any work it performs is at its own risk. Applicant shall take all necessary steps to ensure that work is conducted consistent with *Good Utility Practice*.

10 METERING

10.1 Delivery Meters

All real and reactive power deliveries to the PG&E Electric System from Applicant's Generating Facility shall be metered at each Point of Interconnection[5] with meters meeting the requirements of: (i) Appendix J to the ISO Tariff for interconnections at 60 kV and above ("transmission interconnection"); and (ii) the PG&E Wholesale Distribution Tariff for interconnections below 60 kV ("distribution interconnection"). In addition, meters and metering equipment shall meet the requirements of the PG&E Interconnection Handbook. Any conflicts with regard to metering standards that may arise between this Agreement, the ISO Tariff, or the PG&E Wholesale Distribution Tariff shall be resolved consistent with the applicable tariff. Power deliveries shall be metered at voltage specified for the Interconnection Point in Appendix E.2.1.

10.2 Power Supply Metering Requirements

The Parties shall cooperate in the installation and provision of access to the meters, as necessary for each Party to obtain the information needed to perform as contemplated under this Agreement.

10.3 Requirements for Meters and Meter Maintenance

The Responsible Meter Party's metering equipment located at each Point of Interconnection shall measure and record real and reactive power flows and shall be capable of recording flows in both directions. Such "in" and "out" bi-directional meters shall be designed to prevent reverse registration and shall measure and continuously record such deliveries. Meters, metering transformers and devices shall be maintained and tested annually by the Responsible Meter Party in accordance with applicable metering maintenance and testing standards and guidelines.

10.4 Meter Access

10.4.1 Access to Meter-Related Facilities

The Party that owns meter-related facilities such as metering transformers and devices shall grant reasonable access to allow the other Party to use such meter-related facilities for the other Party's own meters; provided that, the other Party shall compensate the owning Party for actual costs incurred related to such access.

10.4.2 Reading and Maintaining Meters

If required, the other Party shall grant the Responsible Meter Party access to the other

[5] The La Paloma generation project meters are located on the high-side of the generator step-up transformers at the La Paloma Switchyard.

Party's facilities as may be required for meter reading and/or the proper operation and maintenance of all revenue metering facilities.

11 MAINTENANCE OF INTERCONNECTION EQUIPMENT OWNED BY THE APPLICANT

11.1 Modifications to the Interconnection or Protection Devices

Prior to modifying its existing interconnection or protection devices, Applicant agrees to obtain PG&E's written approval; provided that, PG&E's approval shall not be unreasonably withheld or delayed. Applicant shall notify PG&E, in writing, at least sixty (60) days prior to such modification.

11.2 Testing of Interconnection Facilities

PG&E-required Interconnection Facilities owned by Applicant shall be periodically tested and maintained at the manufacturer's accepted specifications, but no less than every four (4) years, by qualified personnel. Copies of equipment test reports shall be forwarded to PG&E for review.

11.3 Relay Requirements

11.3.1 For a Generating Facility rated in excess of 1,000 kW and before the Generating Facility operates in parallel with PG&E, all PG&E-required interconnection relays shall be sealed by PG&E. If a relay is removed for maintenance or repair, the Designated PG&E Switching Center shall be notified. If the seals are broken for any reason, PG&E must inspect the Generating Facility before parallel operation may resume.

11.3.2 Lamicoid or equivalent forms of nameplates or labels shall be installed by Applicant adjacent to all PG&E-required interconnection relays. Each relay nameplate shall include the device number and the relay's function.

12 REFERENCES

The following reference materials, all of which are subject to revision or being superseded from time to time, are available for use by Applicant and its operating personnel. Copies may be requested from the Designated PG&E Switching Center:

12.1 Electric Standard Operating Instructions - A document listing all the standard operating orders followed by PG&E system operators.

12.2 GTS Standard S0403 - A document describing approved PG&E clearance procedures and instructions for obtaining clearances.

12.3 PG&E Interconnection Handbook.

12.4 PG&E Meter Maintenance and Testing Standards (S0008) and Guidelines (G0027).

Applicant shall be solely responsible for possessing and utilizing the latest versions of the above reference materials, and shall provide such materials to its operating personnel.

13 SIGNIFICANT REGULATORY CHANGE

13.1 Automatic Conformance

This Agreement shall be automatically modified without further action of the parties to conform to any final order issued by the FERC that directly addresses a provision or provisions of this

Agreement. Such conformance shall be prospective only and shall not affect any rights or obligations of either party that have accrued as of the date of the order requiring conformance under the terms of this Agreement.

13.2 Notification

If, at any time during the term of this Agreement, either Party becomes aware of a Significant Regulatory Change (whether actual or proposed), including any automatic conformance under Section 13.1 herein, and if such change may reasonably be expected materially to affect either or both Parties' obligations or operations under this Agreement, such Party shall provide written notice to the other Party promptly no later than one (1) month after becoming aware of such Significant Regulatory Change. The notice shall contain a description of the Significant Regulatory Change, including expected time schedules. If the Party giving notice believes that it will be necessary to amend this Agreement to address the anticipated change, then the notice to the other Party may include a proposal that the Parties meet as provided in Section 13.3.2 hereof in order to negotiate an appropriate amendment to this Agreement.

13.3 Amendment of Agreement

13.3.1 Following notification under Section 13.2, the Parties shall meet to discuss whether an amendment to this Agreement is necessary to address the Significant Regulatory Change. Such amendment, if any, shall be limited in scope to what is necessary to allow this Agreement to accommodate the Significant Regulatory Change identified in the notice issued pursuant to Section 13.2.

13.3.2 If the Parties agree that such an amendment to this Agreement is necessary, the Parties will proceed to negotiate in good faith such amendment. If the Parties have not reached agreement within sixty (60) calendar days of the date of the first meeting, any unresolved issues shall be resolved through dispute resolution procedures set forth in Section 15.10. Notwithstanding the above, if any issues remain unresolved as of ninety (90) calendar days before the Significant Regulatory Change is scheduled to take place then, with respect to the unresolved issues, PG&E may, but is not required to, unilaterally file an amendment to this Agreement with FERC pursuant to Section 205 of the FPA, and Applicant may exercise its rights under the FPA to protest or oppose such filing.

13.3.3 If the Parties cannot agree that an amendment to this Agreement is necessary to allow this Agreement to accommodate the Significant Regulatory Change, they shall submit such dispute to dispute resolution proceedings pursuant to Section 15.10; provided, however, that if such dispute is not resolved as of ninety (90) calendar days before the Significant Regulatory Change is scheduled to take place, then PG&E may, but is not required to, unilaterally file an amendment to this Agreement with FERC as set forth in the paragraph above.

13.3.4 Nothing in this Section 13.3 shall be deemed to limit PG&E's right to make changes pursuant to Section 15.23.1.

14 BILLING AND PAYMENT

14.1 PG&E shall bill Applicant for the Costs of performing necessary maintenance during non-working hours at the request of Applicant pursuant to Section 6.4.3.2. Applicant shall pay PG&E for such Costs at:

Pacific Gas and Electric Company
Payment Processing Center
Research Unit / B5A
P.O. Box 770000
San Francisco, CA 94177

PG&E may change the place where payment is made by giving Applicant notice thereof as provided in Section 15.21.

14.2 Payment Due Date

PG&E shall prepare and submit bills to Applicant on or after the first *Business Day* of each calendar month. The payment of any bill shall be due and must be received by PG&E not later than the 30th calendar day following the day on which Applicant receives the bill or, if that 30th day is a Saturday, Sunday or legal holiday, the next *Business Day*. Such date shall be referred to as the "Payment Due Date". A bill shall be deemed delivered and received on the third *Business Day* after the postmarked date unless a copy of the bill is sent by electronic facsimile, in which case it shall be deemed delivered on the same day. If Applicant has a question concerning a bill, it may review the back-up data used in preparation of the bill to the extent that data is still available.

14.3 Estimated Bills

If charges under this Agreement cannot be determined accurately for preparing a bill, PG&E may use its best estimates in preparing the bill and such estimated bill shall be paid by Applicant. Any estimated charges shall be labeled as such and PG&E shall, upon request, document the basis for the estimate used. Estimated bills shall be prepared and paid in the same manner as other bills under this Agreement.

14.4 Disputed Bills

If Applicant disputes all or any portion of a bill submitted by PG&E to Applicant, it nevertheless shall, not later than the Payment Due Date of that bill, pay the bill in full. A dispute between either PG&E or Applicant and any Third Party shall not be a proper basis for withholding payment. Payments to PG&E of Applicant's obligations arising under this Agreement are not subject to any reduction, whether by offset, payments into escrow, or otherwise, except for routine adjustments or corrections as may be agreed to by the Parties or as expressly provided in this Agreement.

14.5 Adjusted Bills

When final and complete billing information becomes available and a charge is determined accurately or billing errors are identified and corrected, PG&E shall promptly prepare and submit an adjusted bill to Applicant, and any additional payments by Applicant shall be made in accordance with the provisions of this Section 14.5. Refunds by PG&E shall be paid to Applicant not later than thirty (30) calendar days after the date of the adjusted bill. All adjustments or corrections of bills under this Agreement shall be subject to the interest provisions of Sections 14.7 and 14.8.

14.6 Interest on Adjusted Bills

Interest on an additional payment shall accrue from the Payment Due Date of the applicable bill and interest on a refund shall accrue from the date payment of the applicable bill was received by PG&E.

14.7 Interest on Unpaid Bills

Any amount due under this Agreement which is not timely paid shall accrue interest from the date prescribed in Section 14.6 until the date payment is made. The interest amount shall be determined using the interest rate applicable to any amount due during a given month and shall be calculated using the methodology for refunds pursuant to Section 35.19(a) of FERC's Regulations, 18 CFR § 35.19(a). This interest rate shall not exceed the maximum interest rate permitted under California law. Interest shall be calculated for the period during which the payment is overdue or the period during which the refund is accruing interest.

14.8 Payment on Disputed Bills

As provided in Section 14.4, if any portion of a bill is disputed, Applicant shall pay the full amount, without offset or reduction, by the Payment Due Date. In addition, Applicant shall, on or before the Payment Due Date, notify PG&E, in writing, of the amount in dispute and the specific basis for the dispute.

PG&E and Applicant shall endeavor to resolve any billing dispute within thirty (30) calendar days of PG&E's receipt of Applicant's notice of a dispute (or such extended period as the Parties may establish). If the Parties cannot agree, either Party may initiate dispute resolution pursuant to Section 15.10.

14.9 Refunds

If, after Applicant has paid the full amount of a disputed bill directly to PG&E, the results of dispute resolution pursuant to Section 15.10 include a determination that the amount due was different than the amount paid by Applicant, a refund by PG&E to Applicant shall include interest for the period from the date Applicant's overpayment was received by PG&E to the date the refund is paid to Applicant. Likewise, an additional payment by Applicant to PG&E shall include interest for the period from the original Payment Due Date to the date Applicant's additional payment is received by PG&E. Interest paid pursuant to this Section 14.9 shall be at the rate determined pursuant to Section 14.7.

14.10 Failure to Make Payment

Applicant's failure to make any payment on or before the applicable Payment Due Date shall constitute a material breach of this Agreement if that failure is not corrected within seven (7) *Business Days* after the other Party delivers written notiee to non-paying Party. In such event, the Party not receiving payment shall be entitled to pursue any legal, equitable and regulatory rights and remedies it may have under this Agreement or otherwise.

15 GENERAL PROVISIONS

15.1 Appendices Included

The following Appendices to this Agreement, as they may be revised from time to time by written agreement of the Parties or by order of FERC, are attached hereto and are incorporated by reference as if fully set forth herein:

Appendix A - Insurance

Appendix B - Routine Test Guidelines and Non-Test Procedures

Appendix C - Dispute Resolution and Arbitration

Appendix D - Elections Made By Applicant for New Generators

Appendix E - Generating Facility Information and Interconnection Capacity

Appendix F - PG&E Interconnection Handbook Waivers

Appendix G - Appendix A of the Reliability Management Agreement

15.2 Accounting

For good cause and upon reasonable notice each Party shall have the right to audit, at its own expense, the relevant records of the other Party (including the relevant records of Applicant's meters) for the limited purpose of determining whether the other Party is meeting its obligations under this Agreement. Such audits shall be limited to the preceding twelve month period and to only those records reasonably required to determine compliance with this Agreement, and each Party agrees to disclose the information obtained in such audit only to those persons, whether employed by such Party or otherwise, that are directly involved in the administration of this Agreement. Each Party agrees that under no circumstances will it use any information obtained in such an audit for any commercial purpose or for any purpose other than assuring enforcement of this Agreement.

15.3 Adverse Determination or Expansion of Obligations

15.3.1 Adverse Determination

If, after the effective date of this Agreement, FERC or any other Governmental Authority of competent jurisdiction determines that all or any part of this Agreement, its operation or effect is unjust, unreasonable, unlawful, imprudent or otherwise not in the public interest, each Party shall be relieved of any obligations hereunder to the extent necessary to comply with or eliminate such adverse determination. The Parties shall promptly enter into good faith negotiations in an attempt to achieve a mutually agreeable modification to this Agreement to address any such adverse determination.

15.3.2 Expansion of Obligations

If, after the effective date of this Agreement, FERC or any other Governmental Authority of competent jurisdiction orders or determines that this Agreement should be interpreted, modified, or significantly extended in such a manner that PG&E or Applicant may be required to extend its obligations under this Agreement to a Third Party, or to incur significant new or different obligations to the other Party or to Third Parties not contemplated by this Agreement, then the Parties shall be relieved of their obligations to the extent lawful and necessary to eliminate the effect of that order or determination, and the Parties shall attempt to renegotiate in good faith the terms and conditions of the Agreement to restore the original balance of benefits and burdens contemplated by the Parties at the time this Agreement was made.

15.3.3 Renegotiation

If, within three (3) months after an order or decision as described in Sections 15.3.1 and 15.3.2, the Parties either: (i) do not agree that a renegotiation is feasible or necessary; or (ii) the Parties cannot agree to amend or supersede this Agreement, then: (a) either Party may submit the dispute for resolution in accordance with procedures set forth in Section 15.10; (b) PG&E may unilaterally file a replacement interconnection agreement with FERC; or (c) either Party may give the other Party written notice of termination, which termination shall be effective thirty (30) calendar days after receipt of the notice by the other Party. The effect of such termination, and the rights of the Parties thereunder, shall be as provided in Section 5.2.

15.4 Assignments

15.4.1 Consent Required

No transfer or assignment of either Party's rights, benefits or duties under this Agreement shall be effective without the prior written consent of the other Party, which consent shall not be unreasonably withheld or delayed; provided, however, that this Section 15.4 shall not apply to interests that arise by reason of any deed of trust, mortgage, indenture or security agreement heretofore granted or executed by either Party. No partial assignment of either Party's rights, benefits or duties shall be permitted under this Agreement unless otherwise agreed to by the Parties.

15.4.2 Assignee's Continuing Obligation

Any successor to or transferee or assignee of the rights or obligations of a Party, whether by voluntary transfer, judicial sale, foreclosure sale or otherwise, shall be subject to all terms and conditions of this Agreement to the same extent as though such successor, transferee, or assignee were an original Party.

15.5 Captions

All indices, titles, subject headings, section titles and similar items are provided for the purpose of reference and convenience and are not intended to affect the meaning of the contents or scope of this Agreement.

15.6 Construction of the Agreement

Ambiguities or uncertainties in the wording of this Agreement shall not be construed for or against either Party, but shall be determined by the Agreement taken in its entirety.

15.7 Control and Ownership of Facilities

The PG&E Electric System shall at all times be and remain in the exclusive ownership, possession and control of PG&E, and nothing in this Agreement shall be construed to give Applicant any right of ownership, possession or control of all or any portion of the PG&E Electric System. All facilities installed by PG&E hereunder shall, unless otherwise agreed by the Parties, at all times be and remain the property of PG&E, notwithstanding that they may be affixed to premises owned or leased by or under license to Applicant.

15.8 Cooperation and Right of Access and Inspection

Each Party shall give to the other all necessary permission to enable it to perform its obligations under this Agreement. Each Party shall give the other Party the right to have its agents, employees and representatives, when accompanied by the agents, employees and representatives of the other Party, enter its premises at reasonable times and in accordance with reasonable rules and regulations for the purpose of inspecting the property and equipment of the Party in a manner which is reasonable for assuring the performance of the Parties under this Agreement.

15.9 Default

15.9.1 Termination for Default

If either Party breaches its material obligations under this Agreement, such breach shall constitute an event of default. If either Party defaults under this Agreement, the other Party may terminate this Agreement; provided, that prior to such termination the other Party must provide the defaulting Party with written notice stating: 1) the Party's intent to terminate; 2) the date of such intended termination; 3) the specific grounds for termination; 4) specific actions which the defaulting Party must take to cure the default, if any; and 5) a reasonable period of time, which shall not be less than sixty (60) calendar days, within which the defaulting Party may take action to cure the default and avoid termination, provided, there is any action which can be taken to cure the default. The pendancy of any dispute resolution procedure pursuant to Section 15.10 with regard to any separate dispute(s), other than the event of default, shall not limit the right to terminate this Agreement under this Section 15.9.

15.9.2 Other Remedies for Default

The remedy under Section 15.9.1 is not exclusive, and subject to Section 15.10 either Party also shall be entitled to pursue any other legal, equitable or regulatory rights and remedies it may have in response to a default by the other Party.

15.10 Dispute Resolution

The Parties shall make best efforts to resolve all disputes arising under this Agreement expeditiously and by good faith negotiation. Where this Agreement specifically calls for resolution of disputes pursuant to this Section 15.10, the Parties shall pursue dispute resolution according to the procedures set forth in Appendix C. In all other circumstances the procedures in Appendix C may be used to resolve disputes upon agreement by both Parties. In the event that a matter is submitted to arbitration under Appendix C, the Parties shall be bound by the determination of the arbitrator(s).

15.11 Governing Law

This Agreement shall be interpreted, governed by and construed under the laws of the State of California, as if executed and to be performed wholly within the State of California.

15.12 Indemnity

15.12.1 Definitions

As used in this Section 15.12, with initial letters capitalized, whether in the singular or the plural, the following terms shall have the following meanings:

15.12.1.1 Accident — Personal injury, death, property damage, or economic loss which:

(a) is sustained by a Third Party ("Claimant"), which is an end use customer of a Party;

(b) arises out of delivery of, or curtailment of, or interruption to electric service, including but not limited to abnormalities in frequency or voltage; and

(c) results from either or both of the following:

(i) engineering, design, construction, repair, supervision, inspection, testing, protection, operation, maintenance, replacement, reconstruction, use, or ownership of either the PG&E Electric System or Applicant's electric system; or

(ii) the performance or non-performance of either Party's obligations under this Agreement.

15.12.1.2 Indemnitee — A Party defined in Section 15.12.2(b).

15.12.1.3 Indemnitor — A Party defined in Section 15.12.2(b).

15.12.2 Indemnity Duty

If a Claimant makes a claim or brings an action against a Party seeking recovery for loss, damage, costs or expenses resulting from or arising out of an Accident, the following shall apply:

(a) That Party shall defend any such claim or action brought against it, except as otherwise provided in this Section 15.12.2.

(b) That Party ("Indemnitor") shall hold harmless, defend and indemnify, to the fullest extent permitted by law, the other Party, its directors or members of its governing board, officers, employees or agents ("Indemnitees"), upon request by the Indemnitee, for claims or actions brought against the Indemnitee allegedly resulting from Accidents caused by acts or omissions of the Indemnitor.

(c) No Party shall be obligated to defend, hold harmless or indemnify the other Party, its directors or members of its governing board, officers, employees or agents for Accidents resulting from the latter Party's gross negligence or willful misconduct.

(d) If a Party successfully enforces this indemnity, the Party against which enforcement is required shall pay all costs, including reasonable attorneys' fees and other litigation expenses, incurred in such enforcement.

15.13 Interpretation

This Agreement is not intended to modify any PG&E or ISO tariff or rule filed with the CPUC or FERC. In case of conflict between this Agreement and any PG&E or ISO tariff or rule, the tariff or rule shall govern. This Agreement, in conjunction with the Supplemental Letter Agreement executed by PG&E on this date, represents the entire understanding between the Parties hereto relating to the interconnection and parallel operation of the Generating Facility with the PG&E Electric System, and supersedes any and all prior proposals or agreements, whether written or oral, that may exist between the Parties except that this Agreement shall not supercede the GSFA executed by the Parties on January 28, 2000. Where there is conflict or inconsistency with the express terms in this Agreement and any documents referenced by this Agreement excluding the above referenced PG&E and ISO tariffs, the terms of this Agreement shall supersede such conflicting terms.

15.14 Judgments and Determinations

When the terms of this Agreement provide that an action may or must be taken, or that the existence of a condition may be established based on a judgment or determination of a Party, such judgment shall be exercised or such determination shall be made reasonably and in good faith, and where applicable in accordance with *Good Utility Practice*, and shall not be arbitrary or capricious.

15.15 Liability

15.15.1 To Third Parties

Nothing in this Agreement shall be construed to create any duty to, any standard of care with reference to, or any liability to, any Third Party.

15.15.2 Between the Parties

Except for its willful misconduct, gross negligence, or with respect to breach of this Agreement, or with respect to the indemnity duty under Section 15.12.2, no Party, nor its directors or members of its governing board, officers, employees or agents shall be liable to another Party for any loss, damage, claim, cost, charge or expense arising from or related to this Agreement. In the event of breach of this Agreement, neither Party, nor its directors or members of its governing board, officers, employees or agents shall be liable to the other Party for any consequential, special or indirect damages.

15.15.3 Protection of a Party's Own Facilities

Each Party shall be responsible for protecting its facilities from possible damage by reason of electrical disturbances or faults caused by the operation, faulty operation, or non-operation of another Party's facilities, and such other Party shall not be liable for any such damage so caused.

15.15.4 Liability for Interruptions

Neither Party shall be liable to the other, and each Party hereby releases the other and its directors, officers, employees and agents from and indemnifies them, to the fullest extent permitted by law, for any claim, demand, liability, loss or damage, whether direct, indirect or consequential, incurred by either Party, which results from the interruption or curtailment in accordance with (i) this Agreement, (ii) *Good Utility Practice*, or (iii) as directed by the ISO, of power flows through a Point(s) of Interconnection made available by PG&E under this Agreement, or of power flows made possible by reason of that Point(s) of Interconnection.

15.16 Modification

This Agreement may be amended or modified only by a written instrument signed by the authorized representatives of both Parties, except as may otherwise herein be expressly provided.

15.17 No Dedication of Facilities

Any undertaking by either Party under any provision of this Agreement is rendered strictly as an accommodation and shall not constitute the dedication by Applicant of any part or all of the Generating Facility or by PG&E of any part or all of the PG&E Electric System to the other, the public, or any Third Party. Any such undertaking by any Party under a provision of, or resulting from, this Agreement shall cease upon the termination of that Party's obligations under this Agreement.

15.18 No Obligation to Offer Same Service To Others

By entering into this Agreement to interconnect with Applicant and filing it with FERC, PG&E does not commit itself to furnish any like or similar undertaking to any other Person.

15.19 No Precedent

This Agreement establishes no precedent with regard to any other entity or agreement. Nothing contained in this Agreement shall establish any rights to or precedent for other arrangements as may exist, now or in future, between PG&E and Applicant for the provision of any interconnection arrangements or any form of electric service.

15.20 No Transmission, Distribution or *Ancillary Services* Provided

Under this Agreement, PG&E does not undertake to provide or make available any transmission service, distribution service, or *Ancillary Services* using any part of the PG&E Electric System for Applicant or any Third Party, or to act as a *Scheduling Coordinator* or in any other capacity as an intermediary for Applicant with others. Nothing in this Agreement shall be construed to preclude Applicant from seeking transmission, distribution, and *Ancillary Services* or other services under a separate arrangement or a successor interconnection agreement with PG&E, or pursuant to any tariff for such service which PG&E may have on file with FERC, or on the basis of other rights that may exist in law or regulation.

15.21 Notices

Except as provided in Sections 8 and 9 above and in Appendix C, all notices or other communications herein provided to be given or which may be given by either Party to the other shall be deemed to have been duly given if delivered by electronic facsimile transmission with confirmed receipt, or when made in writing and delivered in person or deposited in the United States mail, postage prepaid, certified mail, return receipt requested and addressed as follows:

To PG&E:	To Applicant:
Manager, Electric Transmission Services	<u>General Manager La Paloma Generating Plant</u>
Pacific Gas and Electric Company	<u>P.O. Box 175 (mail)</u>
Mail Code B13J	<u>1760 W. Skyline Road (deliveries)</u>
P. O. Box 770000	<u>McKittrick, CA 93251-0175</u>
San Francisco, CA 94177	

Either Party may change any address or location for notices and other communications by giving notice to the other Party as provided in this Section 15.21.

15.22 Non-waiver

Failure by either Party to enforce any right or obligation with respect to any matter arising in connection with this Agreement shall not constitute a waiver as to that matter or any other matter.

15.23 Reservation of Rights

15.23.1 Rate Changes

Nothing contained herein shall be construed as affecting in any way the right of PG&E to unilaterally make application to the FERC for a change in rates under section 205 of the FPA and pursuant to the FERC's Rules and Regulations promulgated thereunder, Applicant shall have the right to protest and object to such change in rates and otherwise to exercise any and all rights it may have with respect thereto, including its rights under Section 206 of the FPA. The term "rates" as used herein shall mean all rates, terms and conditions contained in this Agreement. A change in rates may include, but not be limited to, not only changes in rates and charges but also in the underlying methodology by which such rates and charges are developed.

15.23.2 FPA Disputes

The Parties agree that each Party expressly reserves all of its rights under Sections 202(b) and 210 of the FPA, including the right to seek resolution by FERC of disputes arising under Sections 202(b) and/or 210 of the FPA; provided, however, that the Parties may mutually agree to resolve such dispute through procedures set forth in Section 15.10.

15.24 Rules and Regulations

PG&E and Applicant may each establish and, from time to time, change such procedures, rules, or regulations as they shall determine are necessary in order to establish the methods of operation to be followed in the performance of this Agreement; provided, that any such procedure, rule, or regulation shall not be inconsistent with the provisions of this Agreement. If a Party objects to a procedure, rule, or regulation established by the other Party, it will notify the other Party and the Parties will endeavor to modify the procedure, rule, or regulation in order to resolve the objection. If the Parties cannot reach agreement, either Party may seek to resolve such dispute through procedures set forth in Section 15.10.

15.25 Severability

If any term, covenant or condition of this Agreement or its application is held to be invalid as to any person, entity or circumstance, by FERC or any other regulatory body, or agency or court of competent jurisdiction, then such term, covenant or condition shall cease to have force and effect to the extent of that holding. In that event, however, all other terms, covenants and conditions of this Agreement and their application shall not be affected thereby, but shall remain in full force and effect unless and to the extent that a regulatory agency or court of competent jurisdiction finds that a provision is not separable from the invalid provision(s) of this Agreement.

16 EXECUTION

The signatories hereto warrant and represent that they have been appropriately authorized to enter into this Agreement on behalf of the Party for whom they sign. If Applicant is a Governmental Authority, complete execution on its part requires that a certified copy of a resolution of its governing council, board or other controlling body, authorizing Applicant and those signing on its behalf to enter into this Agreement, must be attached.

Dated this ____ day of ______, _____.

PACIFIC GAS AND ELECTRIC COMPANY

By: S. Bhattacharya
Signature

Shan Bhattacharya
Name

Vice President
Title

August 3, 2001
Date

La Paloma Generating Company, LLC, as agent for La Paloma Generating Trust, Ltd.
Applicant

By: [signature]
Signature

F. JOSEPH FEYDER
Name **VICE PRESIDENT**

Title

7/17/01
Date

APPENDIX A

Insurance[6]

A.1 General Liability Coverage

A.1.1 Applicant shall maintain during the performance hereof Commercial General Liability Insurance for bodily injury, personal injury, and property damage in limits, of combined single limit or equivalent for the results of any one (1) occurrence, of not less than $50,000,000. Such insurance shall provide coverage at least as broad as the Insurance Service Office (ISO) Commercial General Liability Coverage "occurrence" form, with no coverage deletions.[7]

A.1.2 Commercial General Liability Insurance shall include coverage for Premises-Operations, Owners and Contractors Protective, Product/Completed Operations Hazard, Explosion, Collapse, Underground, Contractual Liability, and Broad Form Property Damage including Completed Operations.

A.1.3 Such insurance, by endorsement to the policy(ies), shall include PG&E as an additional insured, shall contain a severability of interest or cross-indemnity clause, shall provide that PG&E shall not by reason of its inclusion as an additional insured incur liability to the insurance carrier for payment of premium for such insurance, and shall provide for thirty (30) calendar days written notice to PG&E prior to cancellation, termination, alteration or material change of such insurance.

A.2 Additional Insurance Provisions

A.2.1 Evidence of coverage described above in Section 1 shall state that coverage provided is primary and is not excess to or contributing with any insurance or self-insurance maintained by PG&E.

A.2.2 PG&E shall have the right to inspect or obtain a copy of the original policy(ies) of insurance.

A.2.3 Applicant shall furnish the required certificates[8] and endorsements to PG&E prior to commencing operation.

A.2.4 All insurance certificates, endorsements, cancellations, terminations, alterations, and material changes of such insurance shall be issued and submitted to the following:

Pacific Gas and Electric Company
Manager, Insurance Department
Mail Code B24H
P. O. Box 770000
San Francisco, CA 94177

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[6] Governmental Authorities which have an established record of self-insurance may provide the required coverage through self-insurance.

[7] The precise amount of insurance coverage will be negotiated by the parties consistent with the risks associated with the specific interconnection.

[8] A Governmental Authority qualifying to maintain self-insurance should provide a statement of self-insurance.

APPENDIX B

Routine Test Guidelines and Non-Test Procedures

B.1 Routine Test Guidelines

The following routine test guidelines apply to a Generating Facility capable of making deliveries of 40 kW or more to the PG&E Electric System.

B.1.1 Applicant shall secondary bench test individual relays by applying the appropriate currents, voltages or frequencies. The relays must be tested at their specified settings to verify the following:

B.1.1.1 Minimum operating point at which relay will actuate (minimum pickup).

B.1.1.2 Time delay for at least three (3) separate multiples of minimum pickup.

B.1.1.3 Phase angle characteristic of directional impedance relays.

B.1.1.4 All relays must meet the following tolerances as applicable under test conditions:

Item	Range
Current	± 10%
Voltage	± 10%
Time	± 10%
Frequency	± 0.5 Hz
Phase Angle	± 5 Degrees

B.1.2 Applicant shall check each protective relay to confirm that the appropriate breaker and/or main breaker is tripped by the relay contact.

B.1.3 Applicant shall check all voltage and frequency relays when energized to confirm that the proper secondary potential is applied.

B.1.4 When the Generating Facility is energized and picking up generation, all relay current coils must be checked by Applicant to confirm that the proper secondary generation current is applied to the relay.

B.2 Non-Test Procedures

B.2.1 Applicant agrees to the following conditions regarding a Non-Test requested by PG&E.

B.2.1.1 Applicant shall not re-energize the affected circuits, whether manually or automatically, without first receiving the approval of the Designated PG&E Switching Center.

B.2.1.2 Applicant agrees to install and maintain permanent warning signs on the Generating Facility's main control panel and at each remote operating location where Applicant has remote closing capability. The warning signs shall instruct personnel to contact PG&E before re-closing the circuit.

APPENDIX C

Dispute Resolution and Arbitration

C.1 Negotiation and Mediation

As provided in Section 15.10, the Parties agree to seek settlement of all disputes arising under this Agreement by good faith negotiation before resorting to other methods of dispute resolution. In the event that negotiations have failed, but before initiating arbitration proceedings under this Appendix C, the Parties may by mutual assent decide to seek resolution of a dispute through mediation. If this occurs, the Parties shall meet and confer to establish an appropriate timetable for mediation, to pick a mediator, and to decide on any other terms and conditions that will govern the mediation.

C.2 Technical Arbitration

C.2.1 The Parties agree that it is in the best interest of both Parties to seek expedited resolution of arbitrable disputes that are technical in nature. Technical disputes may include, without limitation, disputes centered on engineering issues involving technical planning studies, the need for and Cost of Special Facilities, and the Interconnection Capacity of a Point of Interconnection. Such technical issues may be resolved through expert application of established technical knowledge and by reference to *Good Utility Practice* and industry standards.

C.2.2 The Party initiating arbitration pursuant to Section C.3 below shall indicate in its notice to the other Party whether it regards the dispute to be technical in nature. If both Parties agree that a dispute is technical in nature, then the Parties may meet and confer to develop an appropriate timetable and process for expedited resolution of the dispute by a neutral expert, or "technical arbitrator". If the Parties cannot agree that a dispute is technical in nature, or if they cannot agree on a neutral arbitrator, then the Parties may submit the dispute to arbitration under the procedures set forth in Section C.3 below.

C.3 Arbitration

C.3.1 Notices And Selection Of Arbitrators

In the event that a dispute is subject to arbitration under Section 15.10, the aggrieved Party may initiate arbitration by sending written notice to the other Party. Such notice shall identify the name and address of an impartial person to act as an arbitrator. If the other Party agrees that such dispute shall be subject to arbitration, within ten (10) *Business Days* after receipt of notice from the aggrieved Party, the other Party shall give a similar written notice stating the name and address of the second impartial person to act as an arbitrator. Each Party shall then submit to the two named arbitrators a list of the names and addresses of at least three persons for use by the two named arbitrators in the selection of the third arbitrator. If the same name or names appear on both lists, the two named arbitrators shall appoint one of the persons named on both lists as the third arbitrator. If no name appears on both lists, the two named arbitrators shall select a third arbitrator from either list or independently of either list. If the two named arbitrators cannot agree on the selection of the third arbitrator, the third arbitrator shall be appointed by the Chief Judge of the United States District Court for the Northern District of California upon the joint request of the two named arbitrators. Each arbitrator selected under these procedures shall be a person experienced in the construction, design, operation or regulation of electric power transmission facilities, as applicable to the issue(s) in dispute.

C.3.2 Procedures

Within fifteen (15) *Business Days* after the appointment of the third arbitrator, or on such other date to which the parties may agree, the arbitrators shall meet to determine the procedures that are to be followed in conducting the arbitration, including, without limitation, such procedures as may be necessary for the taking of discovery, giving testimony and submission of written arguments and briefs to the arbitrators. Unless otherwise mutually agreed by the parties, the arbitrators shall determine such procedures based upon the purpose of the Parties in conducting an arbitration under Section C3 of this Agreement, specifically, the purpose of utilizing the least burdensome, least expensive and most expeditious dispute resolution procedures consistent with providing each Party with a fair and reasonable opportunity to be heard. If the arbitrators are unable unanimously to agree to the procedures to be used in the arbitration, the arbitration shall be governed by the Commercial Arbitration Rules of the American Arbitration Association.

C.3.3 Hearing and Decision

After giving the Parties due notice of hearing and a reasonable opportunity to be heard, the arbitrators shall hear the dispute(s) submitted for arbitration and shall render their decision with ninety (90) calendar days after appointment of the third arbitrator or such other date selected upon the mutual agreement of the Parties. The arbitrators' decision shall be made in writing and signed by any two of the three arbitrators. The decision shall be final and binding upon the parties; provided, however, under no circumstances are the arbitrators authorized to (i) award any consequential or punitive damages in favor of either Party in rendering a decision and award or (ii) modify the terms and conditions of the Agreement. Judgment may be entered on the decision in any court of competent jurisdiction upon the application of either Party.

C.3.4 Expenses

Each Party shall bear its own costs and the costs and expenses of the arbitrators shall be borne equally by the parties.

APPENDIX D

Elections Made By Applicant for New Generators
(check the appropriate line)

D.1 Transmission Line Selector Switches

For Applicant's interconnected to the PG&E Electric System at 60 kV or above, PG&E shall determine whether transmission line selector switches are required to be installed on the PG&E transmission system to which the tap serving the Generating Facility is connected in order to maintain current reliability or operability of PG&E's transmission system. Should PG&E determine that the selector switches are required, the material and installation Cost of the selector switches shall be at PG&E's expense. PG&E shall indicate what its determination is by checking the appropriate line below. Should PG&E determine that the selector switches are NOT required, Applicant then shall have the option of requesting that transmission line selector switches be installed on the PG&E transmission system serving the Generating Facility, and if so requested PG&E will install such switches at Applicant's Cost. Should PG&E determine that transmission line selector switches are not required to maintain the current reliability or operability of its transmission system, and that such selector switches would solely benefit Applicant's service reliability, PG&E may recommend the installation of the transmission line selector switches. These selector switches can be used for restoring service or preventing service interruption to Applicant. (PG&E and Applicant are to check the appropriate boxes below):

D.1.1 [ ] PG&E has determined that transmission line selector switches are required.

D.1.2 [ ] PG&E has determined that transmission line selector switches are NOT required.

D.1.3. [ ] PG&E has determined that transmission line selector switches are NOT required but recommends that they be installed.

D.1.4 [ ] Applicant has elected to install transmission line switches.

D.1.5 [X] Applicant has elected NOT to install transmission line switches.

D.2 Standby Generator

In the interest of safety, Applicant must promptly notify PG&E before operating or allowing any Third Party to operate any generation sources capable of parallel operation with the PG&E Electric System which are interconnected to the Interconnection Facilities. Applicant shall comply with the requirements identified in the PG&E Interconnection Handbook, as it may be revised or superseded from time to time, for all such generation sources capable of parallel operation with the PG&E Electric System. For PG&E's information and by way of initial compliance with this section, Applicant represents to PG&E that the following is correct:

D.2.1 [ ] Applicant has installed a standby generator.

D.2.2 [X] Applicant does not have and does not plan to install a standby generator.

D.2.3 [ ] While Applicant does not currently have a standby generator installed, it plans to install a standby generator in the future. Applicant will notify the Designated PG&E Switching Center before operating this generator in parallel with the PG&E Electric System.

Applicant shall promptly notify PG&E if the conditions or circumstances indicated above change.

APPENDIX E

Generating Facility Information and Interconnection Capacity

E.1 Generating Facility Information*

E.1.1 Generating Facility is (check one) [X] New, [ ] Existing

E..2 Location of Generating Facility: McKittrick, California.

E.1.3 Description of Generating Facility:

E.1.3.1 Make: Alstom

E.1.3.2 Model: KA24

E.1.3.3 Type: Combined Cycle

E.1.3.4 Serial Nos.: SG2425, SG2443, SG2445, SG2446

E.1.3.5 Nameplate Output Rating: 255,000 @ .85PF kW

E.1.3.6 300,000 kVA

E.1.3.7 21,000 volts, 3 phase, 60 Hertz.

E.1.3.8 Number of units 4

E.2 Interconnection with the PG&E Electric System

E.2.1 Voltage of the Interconnection 230 kV

E.2.2 Interconnection Capacity 1,160,000 kW

E.2.3 Step-up transformer available taps

high side 224.2 kV/230.1 kV/236.0 kV/241.9 kV/247.8 kV

low side 21 kV/ None

Step-up Transformer taps in use: 236.0 kV 21 kV

Step-up Transformer impedance 16.1%

***Refer to Applicant's Application for Certification File with the California Energy Commission for further details.**

APPENDIX F

PG&E Interconnection Handbook Waivers
(Applies to Existing Projects Only)

APPENDIX G

Appendix A of the Reliability Management Agreement

G.1 Definitions

The following definitions apply to this Appendix G:

G.1.1 Member

Any party to the WSCC Agreement.

G.1.2 Reliability Management System (RMS)

The contractual reliability management program implemented through the WSCC Reliability Criteria Agreement, this Appendix G of this Agreement, and any similar contractual arrangement.

G.1.3 Western Interconnection

The area comprising those states and provinces, or portions thereof, in Western Canada, Northern Mexico and the Western United States in which Members of the WSCC operate synchronously connected transmission systems.

G.1.4 WSCC Agreement

The Western Systems Coordinating Council Agreement dated March 20, 1967, as such may be amended from time to time.

G.1.5 WSCC Reliability Criteria Agreement

The Western Systems Coordinating Council Reliability Criteria Agreement dated June 18, 1999, among the WSCC and certain of its member transmission operators, as such may be amended from time to time.

G.1.6 WSCC Staff

Those employees of the WSCC, including personnel hired by the WSCC on a contract basis, designated as responsible for the administration of the RMS.

G.2 Reliability Management System

G.2.1 Purpose

In order to maintain the reliable operation of the transmission grid, the WSCC Reliability Criteria Agreement sets forth reliability criteria adopted by the WSCC to which Applicant and PG&E shall be required to comply.

G.2.2 Compliance

Applicant shall comply with the requirements of the WSCC Reliability Criteria Agreement, including the applicable WSCC reliability criteria set forth in Section IV of Annex A thereof, and, in the event of failure to comply, agrees to be subject to the sanctions applicable to such failure. Such sanctions shall be assessed pursuant to the procedures contained in the WSCC Reliability Criteria Agreement. Each and all of the provisions of the WSCC Reliability Criteria Agreement are hereby incorporated by reference into this Section 2 as though set forth fully herein, and Applicant shall for all purposes be considered a Participant, and shall be entitled to all of the rights and privileges and be subject to all of the obligations of a Participant, under and in connection with the WSCC Reliability Criteria Agreement, including but not limited to the rights, privileges and obligations set forth in Sections 5, 6 and 10 of the WSCC Reliability Criteria Agreement.

G.2.3 Payment of Sanctions

Applicant shall be responsible for payment of any monetary sanction assessed against Applicant by WSCC pursuant to the WSCC Reliability Criteria Agreement. Any such payment shall be made pursuant to the procedures specified in the WSCC Reliability Criteria Agreement.

G.2.4 Transfer of Control or Sale of Generation Facilities.

In any sale or transfer of control of any generation facilities subject to this Agreement, Applicant shall as a condition of such sale or transfer require the acquiring party or transferee with respect to the transferred facilities either to assume the obligations of the Applicant with respect to this Appendix G or to enter into an agreement with PG&E imposing on the acquiring party or transferee the same obligations applicable to Applicant pursuant to this Appendix G.

G.2.5 Publication

Applicant consents to the release by the WSCC of information related to Applicant's compliance with this Appendix G only in accordance with the WSCC Reliability Criteria Agreement.

G.2.6 Third Parties.

Except for the rights and obligations between the WSCC and Applicant specified in this Appendix G, this Appendix G creates contractual rights and obligations solely between the Parties. Nothing in this Appendix G shall create, as between the Parties or with respect to the WSCC: (1) any obligation or liability whatsoever (other than as expressly provided in this Appendix G), or (2) any duty or standard of care whatsoever. In addition, nothing in this Appendix G shall create any duty, liability, or standard of care whatsoever as to any other party. Except for the rights as a third-party beneficiary under this Appendix G, of the WSCC against Applicant, no third party shall have any rights whatsoever with respect to enforcement of any provision of this Agreement. PG&E and Applicant expressly intend that the WSCC is a third-party beneficiary to this Appendix G, and the WSCC shall have the right to seek to enforce against Applicant any provision of this Appendix G, provided, that specific performance shall be the sole remedy available to the WSCC pursuant to Appendix G of this Agreement, and Applicant shall not be liable to the WSCC pursuant to this Agreement for damages of any kind whatsoever (other than the payment of sanctions to the WSCC, if so applicable), whether direct, compensatory, special, indirect, consequential, or punitive.

G.2.7 Reserved Rights

Nothing in the RMS or the WSCC Reliability Criteria Agreement shall affect the right of the ISO, subject to any necessary regulatory approval, to take such other measures to maintain reliability, including disconnection, which the ISO may otherwise be entitled to take.

G.2.8 Severability.

If one or more provisions of this Appendix G shall be invalid, illegal or unenforceable in any respect, it shall be given effect to the extent permitted by applicable law, and such invalidity, illegality or unenforceability shall not affect the validity of the other provisions of this Agreement.

G.2.9 Termination

Applicant may terminate its obligations pursuant to this Appendix G: (a) if after the effective date of this Agreement, the requirements of the WSCC Reliability Criteria Agreement applicable to Applicant are amended so as to adversely affect the Applicant, provided, that Applicant gives fifteen (15) days' notice of such termination to the ISO, PG&E, and the WSCC within forty-five (45) days of the date of issuance of a FERC order accepting such amendment for filing, provided further that the forty-five (45) day period within which notice of termination is required may be extended by Applicant for an additional forty-five (45) days if Applicant gives written notice to the ISO and PG&E of such requested extension within the initial forty-five (45) day period; or (b) for any reason on one year's written notice to the ISO, PG&E, and the WSCC.

G.2.10 Mutual Agreement

This Section Appendix G may be terminated at any time by mutual agreement of PG&E and Applicant.

PRIVILEGED

Privileged and Confidential Informational Omitted Pursuant to 18 C.F.R § 388.112

Attachment 3 – Participating Generator Agreement

Initial Brief of the

California Independent System Operator Corporation

PG&E – La Paloma Unexecuted LGIA

ER21-2592

February 13, 2023

ATTACHMENT CONSISTS OF PRIVILEGED MATERIAL OMITTED

PURSUANT TO 18 C.F.R. § 388.112

CEII

Privileged and Confidential Informational Omitted Pursuant to 18 C.F.R § 388.112

Original Document Contains Critical Energy/Electric Infrastructure Information

Attachment 4 – GIA Conversion Interconnection Request

Initial Brief of the

California Independent System Operator Corporation

PG&E – La Paloma Unexecuted LGIA

ER21-2592

February 13, 2023

ATTACHMENT CONSISTS OF PRIVILEGED MATERIAL OMITTED

PURSUANT TO 18 C.F.R. § 388.112

PRIVILEGED

Privileged and Confidential Informational Omitted Pursuant to 18 C.F.R § 388.112

Attachment 5 – GIA Conversion Affidavit

Initial Brief of the

California Independent System Operator Corporation

PG&E – La Paloma Unexecuted LGIA

ER21-2592

February 13, 2023

ATTACHMENT CONSISTS OF PRIVILEGED MATERIAL OMITTED

PURSUANT TO 18 C.F.R. § 388.112

CEII

Privileged and Confidential Informational Omitted Pursuant to 18 C.F.R § 388.112

Original Document Contains Critical Energy/Electric Infrastructure Information

Attachment 6 – GIA Conversion and Repowering Checklist

Initial Brief of the

California Independent System Operator Corporation

PG&E – La Paloma Unexecuted LGIA

ER21-2592

February 13, 2023

ATTACHMENT CONSISTS OF PRIVILEGED MATERIAL OMITTED

PURSUANT TO 18 C.F.R. § 388.112

CEII

Privileged and Confidential Informational Omitted Pursuant to 18 C.F.R § 388.112

Original Document Contains Critical Energy/Electric Infrastructure Information

Attachment 7 – La Paloma BPM Section 10 Submissions

Initial Brief of the

California Independent System Operator Corporation

PG&E – La Paloma Unexecuted LGIA

ER21-2592

February 13, 2023

ATTACHMENT CONSISTS OF PRIVILEGED MATERIAL OMITTED

PURSUANT TO 18 C.F.R. § 388.112

CEII

Privileged and Confidential Informational Omitted Pursuant to 18 C.F.R § 388.112

Original Document Contains Critical Energy/Electric Infrastructure Information

Attachment 8 – Master File Data

Initial Brief of the

California Independent System Operator Corporation

PG&E – La Paloma Unexecuted LGIA

ER21-2592

February 13, 2023

ATTACHMENT CONSISTS OF PRIVILEGED MATERIAL OMITTED

PURSUANT TO 18 C.F.R. § 388.112

CEII

Privileged and Confidential Informational Omitted Pursuant to 18 C.F.R § 388.112

Original Document Contains Critical Energy/Electric Infrastructure Information

Attachment 9 – 2020 PMax Requests and Results

Initial Brief of the

California Independent System Operator Corporation

PG&E – La Paloma Unexecuted LGIA

ER21-2592

February 13, 2023

ATTACHMENT CONSISTS OF PRIVILEGED MATERIAL OMITTED

PURSUANT TO 18 C.F.R. § 388.112

CEII

Privileged and Confidential Informational Omitted Pursuant to 18 C.F.R § 388.112

Original Document Contains Critical Energy/Electric Infrastructure Information

Attachment 10 – 2019 Mod-025 Data

Initial Brief of the

California Independent System Operator Corporation

PG&E – La Paloma Unexecuted LGIA

ER21-2592

February 13, 2023

ATTACHMENT CONSISTS OF PRIVILEGED MATERIAL OMITTED

PURSUANT TO 18 C.F.R. § 388.112

CEII

Privileged and Confidential Informational Omitted Pursuant to 18 C.F.R § 388.112

Original Document Contains Critical Energy/Electric Infrastructure Information

Attachment 11 – 2022 Mod-025 Data

Initial Brief of the

California Independent System Operator Corporation

PG&E – La Paloma Unexecuted LGIA

ER21-2592

February 13, 2023

ATTACHMENT CONSISTS OF PRIVILEGED MATERIAL OMITTED

PURSUANT TO 18 C.F.R. § 388.112

Attachment 12 – La Paloma Application to Construct Submission to

California Energy Commission: Excerpted Executive Summary

Complete document not currently available online but may be obtained from the CEC.

Initial Brief of the

California Independent System Operator Corporation

PG&E – La Paloma Unexecuted LGIA

ER21-2592

February 13, 2023

BHTZ #22

La Paloma Generating Project

La Paloma Generating Company, LLC

APPLICATION FOR CERTIFICATION

submitted to the

CALIFORNIA ENERGY COMMISSION
JULY 1998

Volume I

Woodward-Clyde

printed on recycled paper

La Paloma Generating Company, LLC

July 10, 1998

DOCKET
98-AFC-2
DATE JUL 1 0 1998
RECD. JUL 1 0 1998

Mr. Stephen Rhoads
Executive Director
California Energy Commission
1516 Ninth Street
Sacramento, California 95814

Dear Mr. Rhoads:

La Paloma Generating Company, LLC, pursuant to the provisions of Title 20, California Code of Regulations, hereby submits this Application for Certification seeking authority to consult and operate the La Paloma Generating Project, a natural gas-fired, nominal 1,000 MW powerplant to be located in Kern County, California.

As an officer of La Paloma Generating Company, LLC, I hereby attest, under penalty of perjury, that the contents of this application are true and accurate to the best of my knowledge.

Dated this 10th day of July, 1998.

Frank De Rosa
Vice President
La Paloma Generating Company, LLC

100 Pine Street, Suite 2000 • San Francisco, California 94111 • 415-675-6400 • Fax 415-675-6450

1.1 INTRODUCTION

La Paloma Generating Company, LLC (the Applicant) is seeking approval from the California Energy Commission (CEC) to construct and operate the La Paloma Generating Project. The project will be a nominally rated 1048 MW natural gas-fired, combined cycle electric generating project. The Applicant proposes to locate the project approximately 1.5 miles east of the community of McKittrick in western Kern County, California.

The La Paloma Generating Project will employ advanced combustion turbine technology to create a highly efficient and environmentally superior source of electricity for California's restructured energy market.

The La Paloma Generating Project's Application for Certification (AFC) has been prepared in accordance with CEC guidelines and provides:

- A description of the proposed project
- A description of the project's selection through the Electricity Report (ER) demand conformance planning process and confirmed in the current ER
- An assessment of its likely impact on the existing environment
- The proposed mitigation to assure that environmental issues are properly and responsibly addressed, and
- Compliance with applicable laws, ordinances, regulations and standards.

1.2 NOI PETITION

On June 11, 1998, the Applicant submitted a "Petition for Interpretation" to the CEC requesting a determination that the La Paloma Generating Project is exempt from the Notice of Intent (NOI) requirements of Public Resources Code (PRC) Section 25502. The Applicant anticipates a decision on this petition on or before this AFC is accepted as data adequate by the CEC.

1.3 PROJECT NEED

California Public Resources Code (PRC) Section 25520(e) requires that an applicant provide a statement of need with information that demonstrates compatibility of the proposed facility with the most recent Electricity Report (ER). PRC Section 25523(f) requires that the CEC make findings consistent with the CEC integrated assessment of need in siting cases, such as this AFC. Facilities must be in conformance with the assessment to receive certification.

The controlling document for this application is ER 96, the most recent Electricity Report. This document establishes the amount of new capacity required for California and sets forth the test that applicants must pass to achieve certification.

1.3.1 Need Conformance Criteria

ER 96 established a needs test for merchant projects, such as the La Paloma Generating Project. The La Paloma Generating Project meets this test. The project is being developed by the La Paloma Generating Company, LLC. No contracts with utility companies have been or will be executed that will commit utility ratepayers to purchase power from the facility. The developer (Applicant) is "at risk" for the sale of the project output.

The capacity represented by the La Paloma Generating Project (1048 MW) added to the capacity of the three generating projects currently before the Commission (High Desert Power Project – 800 MW, Sutter Power Project – 500 MW, Pittsburg District Energy Facility – 500 MW) totals 2,848 MW, which is far below the 6,737 MW found needed in ER 96. Therefore, the La Paloma Generating Project meets the criteria of the Commission's demand conformance guidelines.

1.4 PROJECT SCHEDULE

The project will be constructed by the La Paloma Generating Company, LLC on an approximate 24-month schedule following the issuance of a Notice To Proceed. Construction of the generating facility will occur between month 6 and month 24, including system checkout and start-up.

See Figure 3.8-1 in Section 3.0 for a summary project construction schedule. The Applicant expects to begin commercial operation in the summer of 2001.

1.5 FACILITY LOCATION AND DESCRIPTION

1.5.1 Facility Location

The La Paloma Generating Project plant site is located in western Kern County, about 40 miles west of Bakersfield, California. The site is 23 acres in size and located near the intersection of Reserve Road and Skyline Road about 1.5 miles east of McKittrick in the northeast corner of Township 30 South, Range 22 East (Diablo Base Meridian) (West Elk Hills, California, USGS Quadrangle, 1:24,000 scale). The site has been previously used for oil production. Please refer to Map 3.2-1 (1:72,000 scale on the following page and 1:24,000 scale in Section 3.0) for the location of all project components.

Appendix O contains the assessor's parcel number and property owner's names and addresses for all parcels within 500 feet of the linear facilities and 1,000 feet of the plant site.

1.5.2 Facility Description

The proposed La Paloma Generating Project is a combined cycle power plant. It includes four power islands, a switchyard, control and administrative buildings, cooling towers, storage tanks, parking, and other ancillary facilities.

Each power island will consist of an advanced technology combustion turbine (CTG), a heat recovery steam generator (HRSG), and a steam turbine generator (STG). Together, the four power islands will be nominally rated at 1,048 MW.

At the present time the ABB KA-24 single-shaft combined cycle power island most closely meets the project's requirements. The Applicant is also considering two power islands of General Electric 7FA gas turbines configured in their standard 2-on-1 combined cycle arrangement.

The CTG converts thermal energy produced by the combustion of natural gas into mechanical energy. This mechanical energy is used to drive the unit's electric generator and gas compressor. The four CTGs will be equipped with an inlet air evaporative cooling system to enhance performance on hot days. Each CTG generator is nominally rated at 172 MW (65° F and 55% RH).

Each CTG will exhaust into a heat recovery steam generator. The HRSG design will be a sliding-pressure, unfired, dual-pressure reheat type with horizontal gas flow. Each HRSG includes inlet and outlet ductwork and a 100-foot-tall steel stack.

The HRSG will produce steam for the steam turbine generator. The steam turbine converts thermal energy from steam into mechanical energy that drives the unit's generator. The steam turbine will rotate at 3,600 rpm. It will be a condensing-extraction type reheat turbine with side exhaust. The STG generator is designed for an output nominally rated at 96 MW with HP inlet throttle steam conditions of 2,321 psia and 1,048° F.

A detailed description of the power island components is presented in Section 3.4 (Facility Description), Section 3.5 (Facility Civil/Structural Features), Section 3.6 (Transmission Facilities), and Section 3.7 (Pipelines).

Heat rejection for the power cycle will be accomplished with a two-pass deaerating surface condenser for each STG, a recirculating water system, and two four-cell conventional evaporative cooling towers. The cooling towers will be outfitted with high efficiency mist eliminators to minimize drift.

The La Paloma Generating Project is designed to have very low emissions of air pollutants. It will be one of the cleanest thermal power plants in the United States. Oxides of nitrogen (NO_x) will be controlled by a combination of dry low NO_x combustors and post combustion control. Post combustion control will be either SCONOx™ or selective catalytic reduction (SCR). Emissions of NO_x will be controlled to 2.5 ppmvd at 15 percent O_2.

Emissions of carbon monoxide (CO) will be reduced by good combustion engineering and control. CO emissions will be controlled to 10 ppmvd at 15 percent O_2. Volatile organic compounds (VOC), sulfur dioxide (SO_2), and particulates less than 10 microns in size (PM_{10}) will be reduced by the use of natural gas as the plant's sole fuel type.

1.5.3 Site Layout

Figure 1.5-1 provides an artist's rendering of an aerial view of the facility. Figure 3.4-2 in Section 3.0 provides a site layout showing the location of the facility's components. Figure 3.3-1 in Section 3.0 shows the site elevation and the plant's components. Figure 5.13-1 in Section 5.13, and also shown on the following page presents a photographic reproduction of the existing site area and a color model of the project site after construction.

1.5.4 Transmission Interconnection

The La Paloma Generating Project will interconnect with the Midway Substation, located east of Buttonwillow, California. A new 13.6-mile 230 kV bundled double circuit transmission line is required for the interconnection. The two circuits will be supported by tubular steel structures. The conductors will be 1,590-kcmil ACSR "Falcon", an aluminum conductor with steel reinforcement.

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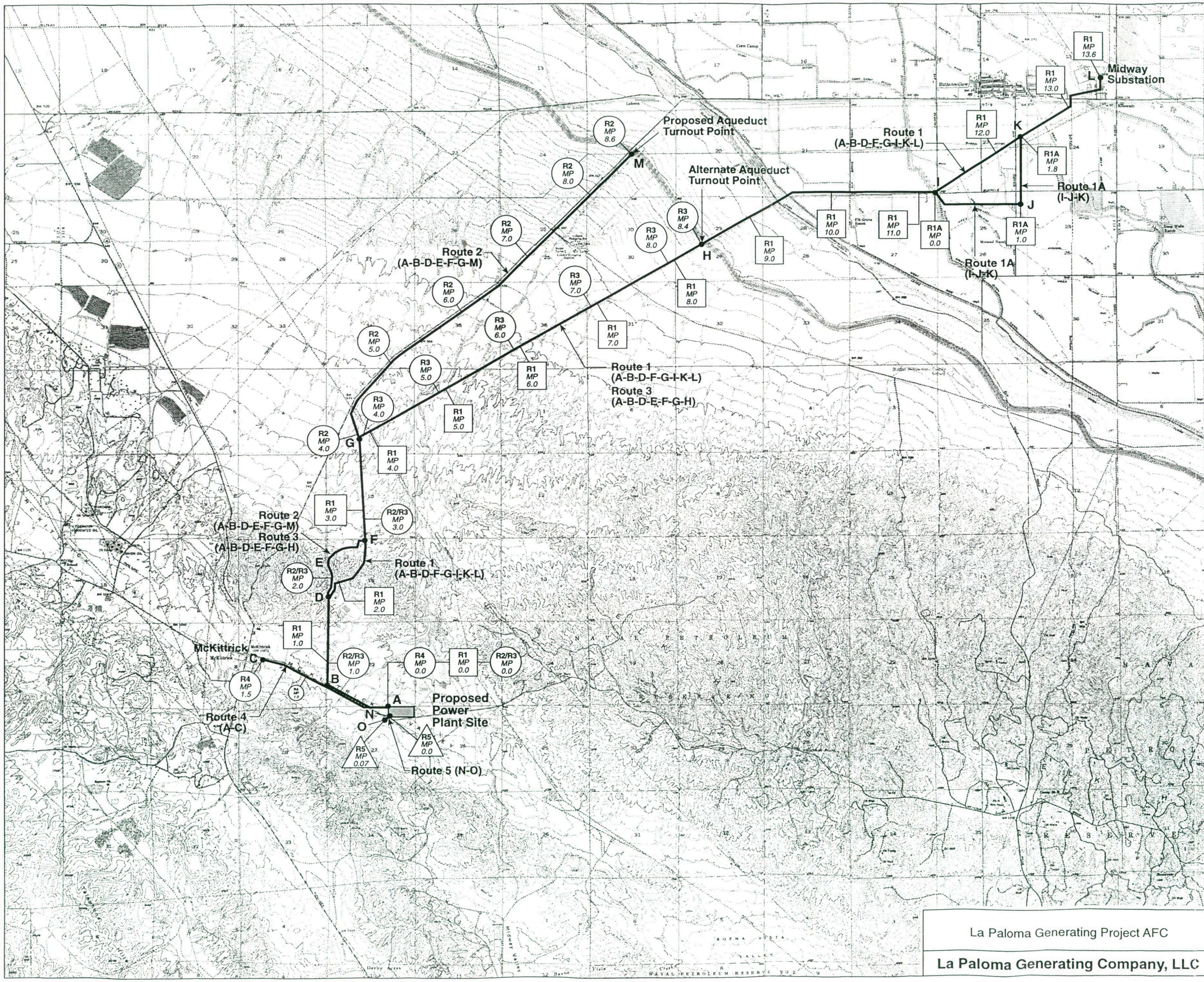


LEGEND

R1 MP 0.0	Transmission Line
R2 MP 0.0	Water Supply Pipeline
R5 MP 0.0	Gas Supply Pipeline

- Route 1 (A-B-D-F-G-I-K-L) – Proposed 230 kV Transmission Line
- Route 1A (I-J-K) – Alternate 230 kV Transmission Line
- Route 2 (A-B-D-E-F-G-M) – Proposed Water Supply Line (Highway 58)
- Route 3 (A-B-D-E-F-G-H) – Alternate Water Supply Line
- Route 4 (A-C) – Potable Water Supply Line
- Route 5 (N-O) – Gas Supply Line

N

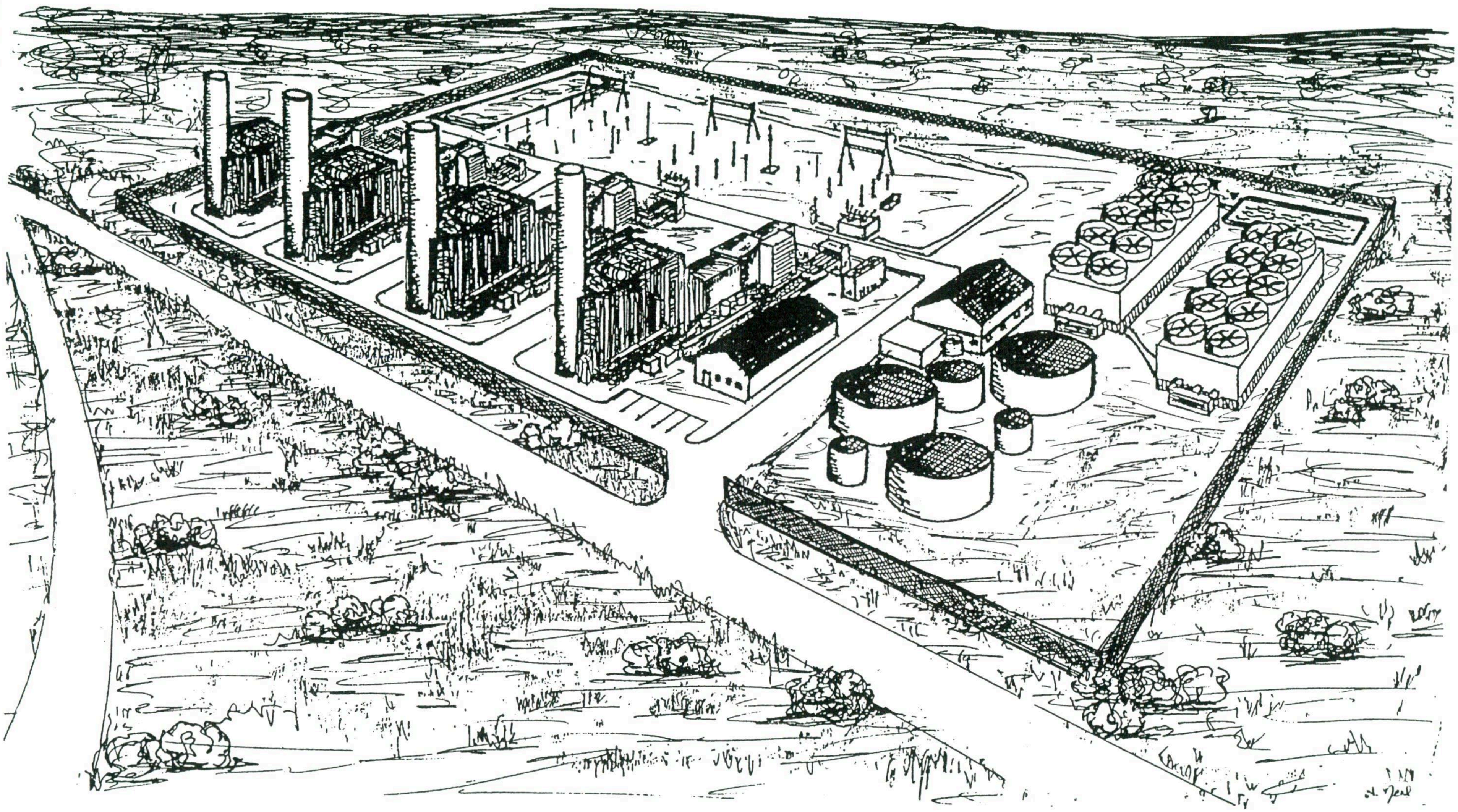
0 6000 12000
feet
(1:72,000)

La Paloma Generating Project AFC **La Paloma Generating Company, LLC**	Map 3.2-1. LOCATION OF LA PALOMA GENERATING PROJECT COMPONENTS	1998

97SB047-0000/062998/gos

La Paloma Generating Project AFC	**Figure 5.13-1. a)** A closeup view of the power plant site, seen from Reserve Rd. (VP 1); **b)** Computer model showing mass and scale of plant facilities relative to VP 1. (Details of piping and other plant features would be visible at this distance.)	1998
La Paloma Generating Company		

This page follows p. 1-5.



La Paloma Generating Project AFC	Figure 1.5-1: ARTIST'S RENDERING OF LA PALOMA FACILITY SITE	
La Paloma Generating Company, LLC		1998

The proposed 230 kV transmission route (Route 1) begins at the plant site and runs along the south side of Reserve Road (all linear components are depicted on Map 3.2-1). The route then turns north and parallels the Midway-Sunset 230 kV transmission line, then turns northeast and parallels the north side of the Diablo-Midway 500 kV transmission line to its termination at Midway Substation (MP 13.6).

Between milepost (MP) 9.5 and MP 13.1, the route crosses irrigated agricultural fields. The new structures will be placed adjacent to the existing Diablo-Midway 500 kV transmission line structures in order to reduce impact on agricultural operations.

1.5.5 Fuel Gas and Interconnection

The proposed generating facility will be fueled by natural gas. There is no oil back-up fuel supply. Natural gas at approximately 735 psig will be delivered to the site from the existing interstate natural gas pipeline jointly owned by the Kern River Gas Transmission Company and the Mojave Pipeline Company. This interstate pipeline runs along the south side of Reserve Road. A new 370-foot pipeline (Route 5) will be constructed from a tie-in point along the existing natural gas pipeline to the plant site.

1.5.6 Water Supply

Raw water will be supplied to the facility by the West Kern Water District. To deliver raw water, a new 24-inch diameter pipeline will be constructed from a new turnout on the California Aqueduct. The facility's average hourly water requirement is 5,300 gpm. This equates to an annual average water requirement of 5,500 acre feet.

The proposed pipeline route (Route 2) begins at the intersection of State Route 58 (SR 58) at the California Aqueduct. The route will run adjacent to the southern edge of the SR 58 right of way for 4.3 miles. The route then turns southeast and follows along unpaved private roads to Reserve Road, where it turns east to parallel Reserve Road 0.9 miles to the plant site. See Section 3.7.2 for more detail about the proposed raw water pipeline route and an alternate route that parallels the Diablo-Midway corridor (Route 3).

Potable water will be supplied by constructing a 1.5-mile, 6-inch diameter pipeline to connect the plant with the existing potable water supply distribution system operated by the West Kern Water District (District). The pipeline (Route 4) will be constructed adjacent to Reserve Road.

The plant's water supply will be secured by entering into a long-term agreement with the West Kern Water District (District). The District receives an annual allotment of 25,000 acre feet from the State Water Project and also possesses 216,000 acre feet of banked groundwater reserves. With the La Paloma Generating Project, the District's annual customer demand will be 19,000 acre feet per year. The District's allotment is more than sufficient to meet its customer demand with the La Paloma Generating Project during normal water years. During dry years when the District does not receive its full allotment, it will use banked water to meet any supply shortfall. The banked water reserve is sufficient to sustain the District's commitments during extended periods of shortfall.

1.5.7 Hazardous Materials and Waste Management

The plant has been designed to minimize the type and quantities of hazardous materials required for plant operation. Where choices of materials present themselves, materials with reduced hazards will be selected. Hazardous material storage and handling facilities will be designed with redundant containment to minimize the impact of spills. For example, the Applicant will use aqueous ammonia for air emission control systems. Although more expensive, aqueous ammonia is significantly less hazardous than anhydrous ammonia in the event of an accidental release.

Approximately 6 to 9 cubic yards per day of non-hazardous filter cake will be generated by the plant's raw water pretreatment system. This material will be transported offsite by a licensed solid waste hauler to a licensed disposal site.

Other non-hazardous solid wastes generated from routine maintenance activities and office operations will be recycled to the extent practical, and the remainder removed on a regular basis by a licensed solid waste hauler and disposed at a licensed disposal site.

Waste oil and small amounts of other hazardous wastes will be generated by plant operations. First priority will be given to recycling these wastes. Wastes that cannot be recycled will be transported by a licensed hazardous waste hauler to a disposal site that is licensed to receive these wastes. Estimates of the quantities of hazardous waste that will be generated during the operation of the project are low enough that the project will qualify as a "Small Quantity Generator" under state and federal waste regulations.

1.5.8 Process Wastewater Discharge

Process wastewater consisting primarily of cooling water blowdown from the circulating cooling water system will be disposed by injection wells into the underlying Tulare formation. The Tulare formation is used by the oil production industry in western Kern County to dispose of process wastewater. Average daily injection of the facility's process wastewater will be 544,000 gallons. Characteristics of the wastewater stream include elevated

TDS levels and residual water treatment chemicals. The injection wells will be classified as either Class I or Class V depending upon the TDS of the water in the underlying formation. Groundwater in the Tulare formation ranges from 4,000 ppm to 21,000 ppm. Receiving formations with water below 10,000 ppm TDS are classified as Class V wells. The Applicant has obtained a permit from the Department of Oil and Gas to drill a test injection well on the project site. The results of this test will determine the design of the injection well disposal system and the class of well. It is anticipated that the process wastewater disposal requirements of the project can be met using 2 or 3 injection wells and 1 back-up well. The wells will be located on the project site or immediately adjacent to it.

1.6 PLANT OPERATION

The La Paloma Generating Project will operate as a base load unit. The plant will be designed with a high degree of automation. Thirty-five full-time employees will be required to operate and maintain the plant. The plant will be staffed 24-hours per day.

1.7 SAFETY

The design of the plant has been developed to ensure the safety and health of both workers and the general public. Design and construction of the facility will be in accordance with the current Uniform Building Code Seismic Zone 4 requirements and current California Building Code requirements.

Safety and emergency systems will be incorporated into the design and construction of the facility to ensure safe and reliable operation. Worker safety programs will be developed for both construction and operation, and implemented to assure compliance with federal and state occupational safety and health requirements.

A detailed discussion of safety features and emergency systems is presented in Sections 4.1 and 4.2.

1.8 ENVIRONMENTAL CONSIDERATIONS

The AFC for the La Paloma Generating Project addresses the following environmental resource issues in detail in Section 5.0, Environmental Resources:

- Air Quality
- Geological Hazards and Resources
- Agriculture and Soils
- Water Resources

- Biological Resources
- Cultural Resources
- Paleontological Resources
- Land Use
- Socioeconomics
- Traffic and Transportation
- Noise
- Visual Resources
- Waste Management
- Hazardous Materials Management
- Public Health / Worker Safety
- Cumulative Impacts.

The Applicant has minimized potential environmental impacts through project design measures, including facility siting and incorporation of Applicant-committed mitigation measures into the proposed project. The project will have insignificant environmental impacts.

1.8.1 Air Quality

Western Kern County is classified as non-attainment with respect to federal and state ambient air quality standards for ozone and PM_{10}. The area is attainment for all other criteria pollutants.

The La Paloma Generating Project is classified as a major source under the San Joaquin Valley Unified Air Pollution Control District's New Source Review (NSR) regulations (Rule 2010). Under the federal Prevention of Significant Deterioration (PSD) requirements, the La Paloma Generating Project is classified as a major source only of nitrogen oxides and carbon monoxide. Because the SJVUAPCD is not delegated PSD permitting authority from the U.S. Environmental Protection Agency (EPA), the application for PSD review must be submitted directly to EPA Region IX.

The plant will employ Lowest Achievable Emission Rate (LAER) technology to reduce emissions of criteria pollutants from the plant. The Applicant's choice of emission control technology is discussed in detail in Section 5.2. The proposed technology will make the La Paloma Generating Project one of the cleanest power plants in the United States.

Modeling of the effects of the La Paloma Generating Project on ambient air quality was accomplished with the use of ISCST3 (Version 97363) (EPA, 1995b). The modeling results show that for all criteria pollutants and averaging periods, the project meets both federal and state ambient air quality standards (AAQS). The effects of the project are below the Significant Impact Levels (SIL) for sulfur dioxide, nitrogen dioxide, and carbon monoxide for all averaging periods. The project is below SIL for PM_{10} annual emissions but above the SIL at a small isolated location on a hill to the southwest of the plant site for the PM_{10} 24-hour averaging period.

These modeling results are conservative because the project is required to purchase sufficient air emission offsets to support reasonable progress toward attainment of Ambient Air Quality Standards (AAQS) in Kern County as part of the SJVUAPCD's New Source Review Rule 2010. Emission Reduction Credits (ERCs) will be purchased by the Applicant from the SJVUAPCD ERC bank to satisfy this requirement.

La Paloma Generating Company, LLC, is currently negotiating with several holders of ERCs in western Kern County to obtain the ERCs required by Rule 2010. ERCs will be obtained for the project's emissions of NO_x, VOC, and SO_x. Limited quantities of PM_{10} are available in the ERC bank, and there is very little potential to create ERCs from existing sources of PM_{10} in the San Joaquin Valley. Consequently, the Applicant proposes to offset the portion of PM_{10} emissions that it cannot obtain from the District's ERC bank by acquiring PM_{10} precursor ERCs. The use of precursor ERCs to offset PM_{10} is allowed by Rule 2010. Both oxides of sulfur (SO_x) and oxides of nitrogen (NO_x) are precursors of PM_{10} and may be used to offset the project's PM_{10} emissions.

In California's deregulated power market, this proposed merchant power plant is predicted to displace older thermal power plants that currently operate on the grid. These older plants are much less efficient (nearly twice the design heat rate) and emit air pollutants at much higher rates per MWH. The La Paloma Generating Project is predicted to have "insignificant impacts" locally and regionally and its emissions will be fully offset by greater than a one-to-one ratio. Power plant displacement will result in significant reductions in air emissions state-wide as older plants reduce operations, repower, and/or shut down.

1.8.2 Geology and Soils

None of the project's major structures or equipment are within the projected trace of any active or potentially active faults. To minimize potential seismic risks, plant structures and equipment will be designed in accordance with UBC Seismic Zone 4 requirements. There are no liquefaction, erosion, sedimentation, landslide, flooding or expansive soil hazards associated with the project location.

The proposed plant site is located in an oil field of declining productivity. Nonetheless, the project will not affect this resource because the site is well above the oil producing sands and beyond the western edge of the existing fields.

1.8.3 Biological Resources

Undeveloped areas in western Kern County provide habitat for a number of sensitive plant and animal habitats. Biological surveys were performed focusing on species that are federal- or state-listed as threatened or endangered, species proposed for listing, candidate species, species of special concern, BLM or California Department of Fish and Game special species, and species from the California Native Plant Society Lists 1, 2 and 3. Surveys were conducted between March 1998 and May 1998. Additional surveys will be conducted through January 1999 to gather information on the occurrence of other species for which surveys could not be conducted during the spring, such as summer-blooming plants and wildlife that is present only in the winter.

Biological impacts have been minimized by siting facilities away from sensitive habitats. The power plant site is located in a disturbed area within a developed oil field. The pipeline and transmission line routes were located to maximize the use of existing roads and transmission line corridors.

The project study area contains several managed areas for wildlife habitat. These include the Lokern Natural Area (30,000 acres) and the following managed lands within the Lokern Natural Area:

- BLM's Lokern Area of Critical Environmental Concern (3,040 acres)
- California Department of Fish and Game and the Department of Water Resources parcels located within the Lokern Natural Area (1,000 acres)
- Center for Natural Lands Management area located within the Lokern Natural Area (3,500 acres)
- Chevron Conservation Bank.

The 23-acre plant site is disturbed and consists of non-native grasslands with some saltbrush scrub. No sensitive plant or animal species were identified on or near the plant site at the time of the surveys. However, the saltbrush scrub in the surrounding area is occupied by some federal- and state-listed species. Implementation of the mitigation measures identified in

Section 5.6.3 in combination with avoidance features specifically addressing sensitive species will mitigate potential impacts.

Construction of the electric transmission line, gas pipeline and water pipelines will require disturbance of habitat occupied by sensitive plant and animal species. The project will employ special construction practices to minimize impacts on sensitive species and their habitats. These practices are identified in Section 5.6.3. La Paloma Generating Company, LLC, will seek approval of its plan to minimize and mitigate the impacts of the project on sensitive species and their habitats both from the CEC and the U.S. Fish and Wildlife Service through a Section 7 consultation. This consultation with the U.S. Fish and Wildlife Service will be conducted as part of the FLPMA permit procedures to construct and operate a portion of the project's electric transmission line on federal lands administered by BLM.

1.8.4 Cultural and Paleontological Resources

Based on existing literature and field investigations, the proposed power plant site and construction lay-down area contain two historic sites that may have elements older than 45 years. Both sites consist of equipment and machinery associated with oil production activities in the area. However, neither site has the integrity or qualities that would make the site eligible for listing under the National Historic Preservation Act or important under Appendix K of CEQA.

Based on field investigations of potential linear routes, construction of the transmission line and pipelines is not expected to negatively affect any significant/important cultural resources. Mitigation measures to be implemented by the project include proper monitoring of grading and excavation activities, avoidance and protection of cultural resources, employee training, and recommended participation by Native American Monitors. These measures will ensure that the project will have no significant adverse impacts on cultural resources.

The project area including the power plant site, construction lay-down area, and project linears (pipelines and transmission lines) contain rock units with a high potential for significant paleontological resources. However, no fossil materials were observed during field surveys. Given that only monitoring during excavation can reveal paleontological specimens, the project will employ a paleontologist to monitor excavation in specific areas. The paleontologist will collect samples for data recovery and analysis. In the event of a significant find, work will be halted and emergency discovery procedures will be implemented. Additional measures taken to protect paleontological resources include worker education, avoidance of resources through placement of project elements, and protection of resources through access restrictions, construction restrictions and/or fencing.

1.8.5 Land Use and Visual Resources

The proposed power plant site and construction lay-down area are within a privately-owned oil and gas production field. This production field is surrounded by disturbed lands associated with petroleum and/or oil fields. There are no sensitive land uses within a one mile radius of the plant site and lay-down area. Construction and operation activities are compatible with existing land uses.

All of the proposed linear routes fall within Kern County. Portions of these proposed routes fall within a half-mile of residences and agricultural lands that are considered sensitive land uses. Residences may experience short-term increases in noise, dust, traffic, and vehicle emissions during construction of the transmission line and pipelines. To minimize impacts to agricultural areas, transmission structures will be located adjacent to existing transmission towers or along the edges of fields where practicable. From a visual perspective, the proposed power plant site and construction lay-down area are consistent with the visual elements of the affected area. This is due primarily to distance, the orientation of the nearest residences, screening by structures, landscaping, and conditions of viewing. Visual impacts along the proposed linear routes are considered minor because most of the existing visual conditions for the subject views are characterized by existing transmission lines. Overall, land use and visual impacts associated with the project are not considered significant because of compatibility with existing uses.

1.8.6 Socioeconomics and Transportation

The study area for socioeconomic impacts includes all communities within a two-hour, one-way commuting distance of the site. Within this study area, the principal urbanized area is the City of Bakersfield, located 35 miles away with a population of approximately 223,000. The remaining communities are rural towns dependent upon agricultural and/or oil field related activities.

Under Executive Order 12898, Environmental Justice, federal screening criteria were applied to the study area. According to the analysis, there appear to be no potential minority or low-income population-based environmental justice issues associated with the construction and operation of this project.

Based on Kern County Building Trades Council estimates concerning workforce settlement patterns and data concerning available housing and services (schools, medical facilities, police, fire, etc.), the construction and operation workforce will not have significant adverse impacts on local communities. The project will create an average of 451 jobs during construction and 35 jobs during operations. Moreover, results from the Impact Analysis for

Planning (IMPLAN) model indicate that the project will create a total of 1000 secondary jobs during construction, and a total of 66 additional jobs once the project is operational.

Construction of the power plant will require the use of heavy equipment such as forklifts, cranes, cement mixers and drilling equipment. In addition, an estimated total of 8,274 truck deliveries will be made over the course of the 19-month construction period. The majority of these deliveries will originate in Bakersfield or Los Angeles. All trucks traveling to the site will use Reserve Road and Skyline Road. Both highways and local roads leading to the site have the capacity to accommodate large increases in traffic without reducing their level of service (LOS) to a significantly adverse level.

The operational workforce of 35 employees will generate roughly 70 vehicle trips per day. This traffic combined with the approximately 11 truck trips per month, will not have a significant adverse impact on traffic.

1.9 SUMMARY

The impacts associated with construction and operation of the proposed La Paloma Generating Project have been considered throughout the planning of this facility. Screening criteria were used to select sites for the power plant and associated linears so as to minimize adverse impacts. In addition, engineering design features such as post-combustion NO_x controls were selected to protect local and regional resources. In those instances where a potential for impacts to the environment have been identified, mitigation measures have been selected to minimize potential impacts.

The proposed 1048 MW La Paloma Generating Project will provide benefits to the local economy and will help the State meet improved electrical generation requirements for the future. By employing advanced combustion turbine technology, the project will create a highly efficient and environmentally superior source of electricity for California's restructured energy market.

Attachment 13 – California Energy Commission Application to Construct Commission Decision:

Excerpted Section I and Section V

(complete document available at

https://efiling.energy.ca.gov/GetDocument.aspx?tn=35900&DocumentContentId=66565)

Initial Brief of the

California Independent System Operator Corporation

PG&E – La Paloma Unexecuted LGIA

ER21-2592

February 13, 2023

I. PROJECT PURPOSE AND DESCRIPTION

Summary and Discussion of the Evidence

The La Paloma Generating Company, LLC (La Paloma; Applicant) is a limited liability corporation formed by PG&E Generating Company (formerly known as U. S. Generating Company). PG&E Generating is an unregulated subsidiary of PG&E Corporation. La Paloma proposes to "... construct and operate an electrical generating facility that supplies economic, reliable, and environmentally sound electrical energy and capacity to the restructured California energy market." (Exs. 1, section 2; 35, p. 5). The La Paloma Generating Project (LPGP) is a 1,048 megawatt (MW) natural gas-fired, combined-cycle power plant. Electrical energy from this merchant power plant [1] will be sold into the California Power Exchange (PX), as well as to wholesale power consumers pursuant to bilateral sales agreements. (Exs. 1, section 3; 35, p. 5).

The LPGP will be located in western Kern County, approximately 40 miles west of Bakersfield and 1.9 miles east of McKittrick, in section 27, near the intersection of Reserve and Skyline Roads. The power plant site is approximately 23 acres in size, and is located within an area of declining oil production. (4/21/99 RT 25, 32).[2]

The power generating facility will consist of four power islands. Each island will be comprised of a combustion turbine generator (CTG), a heat recovery steam generator (HRSG) and exhaust stack, and wet surface cooling condenser. (Exs. 1, section 3; 35, p. 5). Natural gas supplied by a new pipeline will fuel the project. This pipeline will tap into the existing interstate natural gas pipeline located approximately 370 feet west of the plant site; the existing pipeline is jointly owned and operated by Kern River Natural Gas Transmission Company and the Mojave Pipeline Company.

[1] A merchant power plant is one which is privately owned, and whose costs are not borne by utility ratepayers.

[2] "RT" refers to the official reporter's transcript for the date indicated.

The La Paloma Generating Project will use approximately 5,500 acre-feet of water annually. Monthly water requirements will vary, ranging from about 610 acre-feet during February to about 680 acre-feet in August. The West Kern Water District (WKWD) will supply the project with California Aqueduct water via a new eight-mile long pipeline; a turnout from the Aqueduct, a pump station, and a 700,000 galllon storage tank will also be constructed. The water pipeline will largely follow the corridor of state Highway 58. [3] Potable water for domestic needs will be supplied from the WKWD's existing municipal system via a new two-mile pipeline to McKittrick. (Ex. 1, section 3).

Blowdown water from the cooling tower will constitute the primary source of wastewater. This will be disposed either by direct injection or by treatment in a zero discharge system.[4] Sanitary waste will be disposed in an on-site leach field. Storm water run off will be collected by storm drains and directed to a retention basin. (Ex. 35, p. 7).

Applicant also proposes to construct a new bundled 230 kilovolt (kV) double circuit electric transmission line to interconnect the project with PG&E's Midway Substation, located northeast of the project site near the community of Buttonwillow. This transmission tie-line would be from 13.6 to 14.2 miles long,[5] and would parallel the existing Midway-Sunset 230 kV and PG&E Diablo-Midway #2 500 kV transmission line. From the Midway Substation, electrical production from the LPGP will be transmitted to users through the existing utility transmission and distribution network (Exs. 1, section 3; 35, p. 5). The project's general features are shown on Figure 1.

[3] Applicant initially proposed two possible routes for the water supply pipeline, either along the right-of-way of the transmission tie line, or along the corridor of state Highway 58. The testimony of record establishes that Applicant is seeking certification for only the route that follows Highway 58 (Route No. 2; see 4/21/99 RT 21:8-11; see also Ex. 26).

[4] Applicant is seeking the option of using either groundwater injection or zero discharge. (4/21/99 RT 34:12-13). Applicant intends to return to the Commission within 60 days following licensing to indicate which wastewater discharge system it will in fact use (4/21/99 RT 34: 24-26 to 35: 1-5).

[5] There are two possible transmission line routes. Route 1 crosses an ecological reserve managed by the California Department of Fish and Game; Route 1B essentially jogs around this reserve. (4/21/99 RT 32-33; see also Ex.s 26 and 28). The routes are similar in other respects. Though Applicant has requested licensing of both routes, it prefers Route 1 and, as discussed in the "Biological Resources" portion of this Decision (*infra*), is negotiating with CDFG to use this route.

Applicant desires to commence project construction late in 1999; capital costs are estimated at $500 million. The project is expected to create a peak of 727 (and average of 451) construction jobs, as well as 35 permanent operational jobs. Commercial operation is anticipated to begin late in the year 2001.

FINDINGS

Based upon the evidence of record, we find as follows:

1. The project objective is to construct and operate a nominally rated 1,048 MW natural gas-fired combined-cycle merchant power plant.

2. The project consists of the power generation equipment, the transmission interconnection, the raw and potable water supply pipelines, turnout and water storage tank, the natural gas supply pipeline, a communications tower, and appurtenant facilities.

V. ENGINEERING ASSESSMENT

The broad engineering assessment conducted for the La Paloma Generating Project is comprised of individual analyses affecting the facility design, as well as the efficiency and the reliability of the proposed power plant. The subjects of this assessment include not only the power generating equipment, but also other project-related elements such as the associated linear facilities (transmission line, the natural gas supply pipeline, the raw water supply pipeline, and the potable water line).

A. FACILITY DESIGN

Summary and Discussion of the Evidence

The facility design portion of the engineering assessment combines five technical topic areas: geologic hazards; civil engineering; structural engineering; mechanical engineering; and electrical engineering. (4/21/99 RT 83; see also Ex. 1, section 13.5, and Appendices A-G and I). Even though the final design[11] of the project has not yet been determined, sufficient detail nevertheless exists to permit an analysis of whether the project can be designed and constructed both in accordance with applicable law and in a manner that protects environmental quality and public health and safety. As part of this analysis, the necessity for special design features to address unique site conditions is also considered. Finally, Conditions of Certification are established to ensure that the project is in fact designed and constructed in an acceptable manner. (4/21/99 RT 83-84).

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[11] One of the Applicant's witnesses explained the various engineering design phases . The first phase is essentially a feasibility and development analysis in which the general project technologies and economics are assessed. The next step is more detailed and contains a preliminary engineering design. At approximately the time of project certification, Applicant will commence the final detailed engineering phase and detailed procurement of equipment. (4/21/99 RT 79--80).

The project site is located approximately 12.5 miles from the San Andreas Fault. It is in Seismic Zone 4, a designation indicating the highest level of potential earthquake related shaking in California. (4/21/99 RT 84). To address this potentiality, major structures and components (including the combustion turbine generator pedestal and foundation, steam turbine generator pedestal and foundation, heat recovery steam generator structure and foundation, exhaust stack foundation, and cooling tower) will be designed and constructed in conformance with the dynamic analysis requirements of the most recent edition of the California Building Code. [12] (4/21/99 RT 85; Ex. 1, p. 318). Additional studies will also be conducted prior to final facility design in order to identify and mitigate any expansive soils that may be present in the areas of structure foundations. [13]

Mechanical features of the La Paloma project include four combustion turbine generators burning natural gas, with a dry-low NOx combustor used to control NOx; four heat recovery steam generators, dual pressure, unfired, reheat type; four steam turbine generators, condensing reheat type; feed water system; two wet cooling towers; turbine inlet air cooling systems, evaporative type; water and wastewater treatment equipment; pressure vessels, piping systems and pumps; aqueous ammonia storage, handling and piping system; air compressors; fire protection systems; and heating, ventilating, air conditioning, potable water, plumbing and sanitary sewage systems.[14] (Ex.1, p.318). The mechanical systems will be designed in accordance with applicable codes and standards.

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[12] The 1998 edition of the California Building Code is currently in effect. Should this version be superseded by the time that the final plans for the LPGP are submitted, however, the successor version will be used . (4/21/99 RT 90, 91:4- 18). Equipment items and components subjected to dynamic analysis requirements will be described in detail prior to the start of that increment of construction of which they are a part. (4/21/99 RT 94).

[13] At the time of the April evidentiary hearings, Applicant was in the process of taking and analyzing additional soil borings. (4/21/99 RT 74 - 77; see also Ex. 35, p. 322).

[14] The La Paloma Generating Project will consist of four power trains, each composed of one ASEA Brown Boveri (ABB) KA-24 172 MW gas turbine, one heat recovery steam generator, and one 96 MW steam turbine driving an electric generator. (Exs. 1, section 3; 35, p. 365).

The major electrical equipment associated with the project includes: the 13.6 to 14.2 mile long 230 kV double-circuit transmission line (discussed in detail later in this Decision), four high voltage switchyard breakers with disconnect switches, four generator step-up transformers, two unit auxiliary transformers, two generator circuit breakers, and power control wiring, protective relaying, grounding system, site lighting, and cathodic protection system. (Ex. 35, p. 319).

The evidence of record concerning design of the facility also includes the ancillary linear facilities. The transmission line will be routed to avoid impacting existing oil field facilities and associated maintenance activities. (4/21/99 RT 90). The eight-mile long raw water supply pipeline will be 24 inches in diameter and sized to deliver the anticipated peak flow of 5,000 gallons per minute; a pumping station will also be constructed as part of the project . The natural gas supply line will be approximately 370 feet long and 20 inches in diameter; it will be buried at least 36 inches and will be suitably coated and cathodically protected against corrosion. The potable water supply line will be six inches in diameter, approximately 9,000 feet long, and designed to withstand a pressure of 150 pounds per square inch. (Ex. 35, p. 320).

The testimony of record indicates the Conditions of Certification will ensure that the final design and construction of the project complies with applicable standards . Contained in these Conditions are requirements specifying the roles, qualifications, and responsibilities of engineers overseeing project design and construction. The Conditions also require that no element of construction proceed without approval from the local building official and that qualified special inspectors perform appropriate inspections required by the California Building Code.[15] (4/21/99 RT 86 -87).

[15] In this instance, the local Chief Building Official serves as the delegatee of the Commission.

The environmental impacts of the project are discussed elsewhere in this Decision (for example, under topics such as Biological Resources and Noise). The testimony indicates that Facility Design considerations do not pose the potential for creating cumulative impacts.

Finally, the testimony addresses potential project closure under three scenarios: planned closure, unexpected temporary closure, and unexpected permanent closure. The testimony of record indicates that the general closure provisions contained in the Compliance Plan (*ante*) and supplemented by Condition of Certification GEN-9 are sufficient to adequately address and minimize any potential adverse impacts associated with project closure. (4/21/99 RT 92; Ex. 35, pp. 323-324).

FINDINGS AND CONCLUSIONS

Based upon the uncontroverted evidence of record, we find and conclude as follows:

1. The La Paloma Generating Project is currently in the preliminary design stage.

2. The evidence of record contains sufficient information to establish that the proposed facility can be designed and constructed in conformity with the applicable laws, ordinances, regulations, and standards set forth in the appropriate portion of Appendix A of this Decision.

3. The Conditions of Certification set forth below are necessary to ensure that the project is designed and constructed both in accordance with applicable law and in a manner that protects environmental quality and public health and safety.

4. The Facility Design aspects of the proposed project do not create potential cumulative impacts.

5. The Conditions of Certification below and the provisions of the Compliance Plan contained in this Decision set forth requirements to be followed in the event of the planned, or the unexpected temporary, or the unexpected permanent closure of the facility.

We therefore conclude that with the implementation of the Conditions of Certification listed below, the La Paloma Generating Project is likely to be designed and constructed in conformity with applicable law pertinent to its geologic, and its civil, structural, mechanical, and electrical engineering, aspects.

CONDITIONS OF CERTIFICATION

GEN-1 The project owner shall design, construct and inspect the project in accordance with the California Building Code (CBC)[16] and all other applicable laws, ordinances, regulations, and standards (LORS) in effect at the time initial design plans are submitted to the Chief Building Official (CBO) for review and approval. The CBC in effect is that edition that has been adopted by the California Building Standards Commission, and published at least 180 days previously.

In the event the LPGP is designed to a successor edition to the 1998 CBC, the 1998 CBC provisions identified herein shall be replaced with the applicable successor provisions.

Where, in any specific case, different sections of the code specify different materials, methods of construction, or other requirements, the most restrictive shall govern. Where there is a conflict between a general requirement and a specific requirement, the specific requirement shall govern.

<u>**Verification:**</u> Within thirty (30) days (or a lesser number of days mutually agreed to by the project owner and the CBO) after receipt of the Certificate of Occupancy, the project owner shall submit to the Compliance Project Manager (CPM) a statement of verification, signed by the responsible design engineer, attesting that all designs, construction, installation and inspection requirements of the applicable LORS and the Commission’s Decision have been met for facility design. The project owner shall provide the CPM a copy of the Certificate of Occupancy in the next Monthly Compliance Report after

[16] All the Sections, Chapters, Appendices and Tables in these Conditions, unless otherwise stated, refer to Sections, Chapters, Appendices and Tables of the 1998 California Building Code (CBC).

receipt of the permit from the CBO [1998 CBC, Section 109 – Certificate of Occupancy.]

GEN-2 The project owner shall furnish to the CPM and to the CBO a schedule of facility design submittals, a Master Drawing List, and a Master Specifications List. The schedule shall contain a description and list of proposed submittal packages for design, calculations, and specifications for major structures and equipment (see list of major structures and equipment below). To facilitate audits by Commission staff, the project owner shall provide designated packages to the CPM when requested.

FACILITY DESIGN Table 1

Major Equipment List

Quantity	Description	Size/Capacity	Remarks
4	Combustion Turbine (CT)	172 MW	Dry low ox combustion control and starter package.
4	Steam Turbine	96 MW	Condensing reheat type.
4	Generator	300 MVA	Hydrogen cooling system.
4	CT inlet filter	640,000 CFM	
4	Heat Recovery Steam Generator (HRSG)	480,587 lb./hr.	HP and LP.
4	HRSG Stack	18'-6" dia.X100' high	Steel stack.
1	Aqueous ammonia	45,000 gal.	Ammonia storage tank.
1	Fire/service	600,000 gal.	Water storage tank.
1	Demineralized water	180,000 gal.	Demineralized water storage tank.
4	Circulating water pumps	55,000 gpm	
1	Water storage reservoir tank	700,000 gal.	Welded steel storage reservoir.
2	Wet cooling towers	590 mm Btu/hr.	
4	Step-up transformers	18 kV to 230 kV	To electrical grid.

FACILITY DESIGN Table 2

Major Structures, Equipment and Associated Foundations

Quantity	Description	Dimensions (ft)*		
		Length	Width	Height
4	Combustion gas turbine generator and starter package (CT)	50	45	20
4	CT air inlet filter with air cooling system	100	20	35
4	Generator with enclosure	40	20	25
4	Heat Recovery Steam Generator (HRSG)	130	45	65
4	HRSG stack		18.5 dia.	100
4	Selective catalytic reduction skid (SCR)	20	15	10
4	Steam turbine pedestal w/turbine and condenser	45	50	30
4	Auxiliary transformer	45	45	25
4	Step-up transformer	45	30	25
1	Demineralized water storage tank		40 dia.	20
1	Fire/Service water storage tank		60 dia.	30
1	Aqueous ammonia storage tank		26 dia.	12
2	Wet cooling tower	230	65	40
1	Water storage reservoir		74 dia.	24
1	Free-standing communication tower			30
1	Switchyard buses and towers	700	230	35
1	Electrical/administrative/control building	60	80	20
4	Gas compressors	41	57	23

*Dimensions are approximate

Verification: At least sixty (60) days (or a lesser number of days mutually agreed to by the project owner and the CBO) prior to the start of rough grading, the project owner shall submit the schedule, a Master Drawing List, and a Master Specifications List to the CBO and to the CPM. The project owner shall provide schedule updates in the Monthly Compliance Report.

GEN-3 The project owner shall make payments to the CBO for design review, plan check, and construction inspection equivalent to the fees listed in the 1998 CBC, Chapter 1, Section 107 and Table 1-A – Building Permit Fees; Appendix Chapter 33, Section 3310 and Table A-33-A – Grading Plan Review Fees, and Table A-33-B – Grading

Permit Fees. If Kern County has adjusted the CBC fees for design review, plan check, and construction inspection, the project owner shall pay the adjusted fees.

<u>Verification:</u> The project owner shall make the required payments to the CBO at the time of submittal of the plans, design calculations, specifications, or soil reports. The project owner shall send a copy of the CBO's receipt of payment to the CPM in the next Monthly Compliance Report indicating that the applicable fee has been paid.

GEN-4 Prior to the start of rough grading, the project owner shall assign a California registered architect, structural engineer, or civil engineer as a resident engineer (RE) to be in general responsible charge of the project. [Building Standards Administrative Code (Cal. Code of Regs., Tit. 24, § 4-209 – Designation of Responsibilities).]

The RE may delegate responsibility for portions of the project to other registered engineers. Registered mechanical and electrical engineers may be delegated responsibility for mechanical and electrical portions of the project, respectively. A project may be divided into parts, provided each part is clearly defined as a distinct unit. Separate assignment of general responsible charge may be made for each designated part.

<u>Protocol:</u> The RE shall:

1. monitor construction progress to ensure compliance with LORS;

2. ensure that construction of all the facilities conforms in every material respect to the applicable LORS, approved plans, and specifications;

3. prepare documents to initiate changes in the approved drawings and specifications when directed by the project owner or as required by conditions on the project;

4. be responsible for providing the project inspectors and testing agency(ies) with complete and up-to-date set(s) of stamped drawings, plans, specifications, and any other required documents;

5. be responsible for the timely submittal of construction progress reports to the CBO from the project inspectors, the contractor, and other engineers who have been delegated responsibility for portions of the project; and

6. be responsible for notifying the CBO of corrective action or the disposition of items noted on laboratory reports or other tests as not conforming to the approved plans and specifications.

The RE shall have the authority to halt construction and to require changes or remedial work if the work does not conform to applicable requirements.

If the RE or the delegated engineers are reassigned or replaced, the project owner shall submit the name, qualifications, and registration number of the newly assigned engineer to the CBO for review and approval. The project owner shall notify the CPM of the CBO's approval of the new engineer.

Verification: At least thirty (30) days (or a lesser number of days mutually agreed to by the project owner and the CBO) prior to the start of rough grading, the project owner shall submit to the CBO for review and approval the name, qualifications, and registration number of the RE and any other delegated engineers assigned to the project. The project owner shall notify the CPM of the CBO's approval(s) of the RE and other delegated engineer(s) within five (5) days of the approval(s).

If the RE or the delegated engineer(s) are subsequently reassigned or replaced, the project owner has five (5) days in which to submit the name, qualifications, and registration number of the newly assigned engineer to the CBO for review and approval. The project owner shall notify the CPM of the CBO's approval of the new engineer within five (5) days of the approval.

GEN-5 Prior to the start of rough grading, the project owner shall assign at least one of each of the following California registered engineers to the project: a) a civil engineer; b) a geotechnical engineer or a civil engineer experienced and knowledgeable in the practice of soils engineering; c) a design engineer who is either a structural engineer or a civil engineer who is fully competent and proficient in the design of power plant structures and equipment supports; d) a mechanical engineer; and e) an electrical engineer. [California Business and Professions Code, Section 6704 et seq., and sections 6730 and 6736; requires state registration to practice as a civil engineer or structural engineer in California.]

The tasks performed by the civil, mechanical, electrical, or design engineers may be divided between two or more engineers, as long as each engineer is responsible for a particular segment of the project (e.g. proposed earthwork, civil structures, power plant structures, equipment support). No segment of the project shall have more than one responsible engineer. The transmission line may be the responsibility of a separate California registered electrical engineer.

The project owner shall submit to the CBO for review and approval the names, qualifications, and registration numbers of all engineers assigned to the project. [1998 CBC, section 104.2 – Powers and Duties of Building Official.]

If any one of the designated engineers is subsequently reassigned or replaced, the project owner shall submit the name, qualifications, and registration number of the newly assigned engineer to the CBO for review and approval. The project owner shall notify the CPM of the CBO's approval of the new engineer.

Protocol: A: The civil engineer shall:

1. design (or be responsible for the design), stamp, and sign all plans, calculations, and specifications for proposed site work, civil works, and related facilities. At a minimum, these include: grading, site preparation, excavation, compaction, construction of secondary containment, foundations, erosion and sedimentation control structures, drainage facilities, underground utilities, culverts, site access roads, and sanitary sewer systems; and

2. provide consultation to the RE during the construction phase of the project, and recommend changes in the design of the civil works facilities and changes in the construction procedures.

Protocol: B: The geotechnical engineer or civil engineer experienced and knowledgeable in the practice of soils engineering shall:

1. review all the engineering geology reports, and prepare the final soils grading report;

2. prepare the soils engineering reports required by the 1998 CBC, Appendix Chapter 33, Section 3309.5 – Soils Engineering Report, and Section 3309.6 – Engineering Geology Report;

3. be present, as required, during site grading and earthwork to provide consultation and monitor compliance with the requirements set forth in the 1998 CBC, Appendix Chapter 33, Section 3317 – Grading Inspections;

4. recommend field changes to the civil engineer and RE;

5. review the geotechnical report, field exploration report, laboratory tests, and engineering analyses detailing the nature and extent of the site soils that may be susceptible to liquefaction, rapid settlement, or collapse when saturated under load; and

6. prepare reports on foundation investigation to comply with the 1998 CBC, Chapter 18, Section 1804 – Foundation Investigations.

   This engineer shall be authorized to halt earthwork and to require changes if site conditions are unsafe or do not conform with predicted conditions used as a basis for design of earthwork or foundations. [1998 CBC, Section 104.2.4 – Stop orders.]

   Protocol: C: The design engineer shall:

1. be directly responsible for the design of the proposed structures and equipment supports;

2. provide consultation to the RE during design and construction of the project;

3. monitor construction progress to ensure compliance with LORS;

4. evaluate and recommend necessary changes in design; and

5. prepare and sign all major building plans, specifications and calculations.

   Protocol: D: The mechanical engineer shall be responsible for, and sign and stamp a statement with, each mechanical submittal to the CBO stating that the proposed final design plans, specifications, and calculations conform with all of the mechanical engineering design requirements set forth in the Commission Decision.

   Protocol: E: The electrical engineer shall:

1. be responsible for the electrical design of the project; and

2. sign and stamp electrical design drawings, plans, specifications, and calculations.

Verification: At least thirty (30) days (or a lesser number of days mutually agreed to by the project owner and the CBO) prior to the start of rough grading, the project owner shall submit to the CBO for review and approval the names, qualifications, and registration numbers of all the responsible engineers assigned to the project. The project owner shall notify the CPM of the CBO's approval(s) of the engineers within five (5) days of the approval(s).

If the designated responsible engineer is subsequently reassigned or replaced, the project owner has five (5) days in which to submit the name, qualifications, and registration number of the newly assigned engineer to the CBO for review and approval. The project owner shall notify the CPM of the CBO's approval of the new engineer within five (5) days of the approval.

GEN-6 Prior to the start of an activity requiring special inspection, the project owner shall assign to the project qualified and certified special inspector(s) who shall be responsible for the special inspections required by the 1998 CBC, Chapter 17, Section 1701 – Special Inspections and Section – 1701.5 Type of Work (requiring special inspection), Section 106.3.5 – Inspection and observation program.

Protocol: The Special Inspector shall:

1. be a qualified person who shall demonstrate competence, to the satisfaction of the CBO, for inspection of the particular type of construction requiring special or continuous inspection;

2. observe the work assigned for conformance with the approved design drawings and specifications;

3. furnish inspection reports to the CBO and RE. All discrepancies shall be brought to the immediate attention of the RE for correction then, if uncorrected, to the CBO and the CPM; and,

4. submit a final signed report to the RE, CBO, and CPM stating whether the work requiring special inspection was, to the best of the inspector's knowledge, in conformance with the approved plans and specifications and the applicable provisions of the applicable edition of the CBC.

A certified weld inspector [certified American Welding Society (AWS) and/or American Society of Mechanical Engineers (ASME) as applicable] shall inspect welding performed on-site requiring special inspection (including structural, piping, tanks and pressure vessels).

Verification: At least fifteen (15) days prior to the start of an activity requiring special inspection, the project owner shall submit to the CBO for review and approval, with a copy to the CPM, the name(s) and qualifications of the certified weld inspector(s), or other certified special inspector(s) assigned to the project to perform one or more of the duties set forth above. The project owner shall also submit to the CPM a copy of the CBO's approval of the qualifications of all special inspectors in the next Monthly Compliance Report.

If the special inspector is subsequently reassigned or replaced, the project owner has five (5) days in which to submit the name and qualifications of the newly assigned special inspector to the CBO for approval. The project owner shall notify the CPM of the CBO's approval of the newly assigned inspector within five (5) days of the approval.

GEN-7 The project owner shall keep the CBO informed regarding the status of construction. If any discrepancy between design and construction is discovered during construction, the project owner shall prepare and submit a non-conformance report (NCR) describing the nature of the discrepancy to the CBO. The NCRs shall reference this Condition of Certification, and applicable sections of the applicable edition of the CBC.

<u>Verification</u>: The project owner shall submit monthly construction progress reports to the CBO and CPM. The project owner shall transmit a copy of the CBO's approval or disapproval of any corrective action taken to resolve a discrepancy to the CPM within fifteen (15) days. If disapproved, the project owner shall advise the CPM, within five (5) days, of the reason for disapproval and the revised corrective action to obtain CBO's approval.

GEN-8 The project owner shall obtain the CBO's final approval of all completed work. The project owner shall request the CBO to inspect the completed structure and review the submitted documents. When the work and the "as-built" and "as graded" plans conform to the approved final plans, the project owner shall notify the CPM regarding the CBO's final approval. The marked up "as-built" drawings for the construction of structural and architectural work shall be submitted to the CBO. Changes approved by the CBO shall be identified on the "as-built" drawings. [1998 CBC, Section 108 – Inspections.]

<u>Verification:</u> Within fifteen (15) days of the completion of any work, the project owner shall submit to the CBO, with a copy to the CPM, (a) a written notice that the completed work is ready for final inspection, and (b) a signed statement that the work conforms to the final approved plans.

GEN-9 The project owner shall file a closure/decommissioning plan with the CPM and Kern County for review and approval at least twelve (12) months (or other mutually agreed to time) prior to commencing the closure activities.

<u>Protocol:</u> The closure plan shall include a discussion of the following:

1. the proposed closure/decommissioning activities for the project and all appurtenant facilities constructed as part of the project;

2. all applicable LORS, all local/regional plans, and a discussion of the conformance of the proposed decommissioning activities to the applicable LORS and local/regional plans;

3. activities necessary to restore the site if the decommissioning plan requires removal of all equipment and appurtenant facilities; and

4. closure/decommissioning alternatives, other than complete restoration of the site.

<u>Verification</u>: At least twelve (12) months prior to closure or decommissioning activities, the project owner shall file a copy of the closure/decommissioning plan with Kern County and the CPM for review and approval.

GEO-1 Prior to the start of construction, the project owner shall assign to the project an engineering geologist(s), certified by the State of California, to carry out the duties required by the 1998 CBC, Appendix Chapter 33, Section 3309.4. The certified engineering geologist(s) assigned must be approved by the CPM (the functions of the engineering geologist can be performed by the responsible geotechnical engineer, if that person has the appropriate California license).

<u>Verification:</u> At least thirty (30) days (or a lesser number of days mutually agreed to by the project owner and the CBO) prior to the start of construction, the project owner shall submit to the CBO for approval the name(s) and license number(s) of the certified engineering geologist(s) assigned to the project. The submittal shall include a statement that CBO approval is needed. The CBO will approve or disapprove of the engineering geologist(s) and will notify the project owner and CPM of its findings within fifteen (15) days of receipt of the submittal.

If the engineering geologist(s) is subsequently replaced, the project owner shall submit for approval the name(s) and license number(s) of the newly assigned individual to the CBO and CPM. The CBO will approve or disapprove of the engineering geologist(s) and will notify the project owner and the CPM of the findings within fifteen (15) days of receipt of the notice of personnel change.

GEO-2 The assigned engineering geologist shall carry out the duties required by the 1998 CBC, Appendix Chapter 33, Section 3309.4 – Engineered Grading Requirement, and Section 3318.1 – Final Reports. Those duties are:

1. Prepare the Engineering Geology Report. This report shall accompany the Plans and Specifications when applying to the CBO for the grading permit.

2. Monitor geologic conditions during construction.

3. Prepare the Final Geologic Report.

Protocol: The Engineering Geology Report required by the 1998 CBC, Appendix Chapter 33, Section 3309.3 Grading Designation, shall include an adequate description of the geology of the site, conclusions and recommendations regarding the effect of geologic conditions on the proposed development, and an opinion on the adequacy, for the intended use, of the site as affected by geologic factors.

The Final Geologic Report to be completed after completion of grading, as required by the 1998 CBC, Appendix Chapter 33, Section 3318.1, shall contain a final description of the geology of the site and any new information disclosed during the grading and the effect of same on recommendations incorporated in the approved grading plan. Engineering geologists shall submit a statement that, to the best of their knowledge, the work within their area of responsibility is in accordance with the approved Engineering Geology Report and applicable provisions of this chapter.

Verification: (1) Within fifteen (15) days after submittal of the application(s) for grading permit(s) to the CBO, the project owner shall submit a signed statement to the CPM stating that the Engineering Geology Report has been submitted to the CBO as a supplement to the plans and specifications and that the recommendations contained in the report are incorporated into the plans and specifications. (2) Within ninety (90) days following completion of the final grading, the project owner shall submit copies of the Final Geologic Report required by the 1998 CBC, Appendix Chapter 33, Section 3318 Completion of Work, to the CPM and the CBO.

CIVIL-1 Prior to the start of site grading, the project owner shall submit to the CBO for review and approval the following:

1. design of the proposed drainage structures and the grading plan;

2. an erosion and sedimentation control plan;

3. related calculations and specifications, signed and stamped by the responsible civil engineer; and

4. soils report as required by the 1998 CBC, Appendix Chapter 33, Section 3309.5 – Soils Engineering Report and Section 3309.6 – Engineering Geology Report.

Verification: At least fifteen (15) days prior to the start of site grading, the project owner shall submit the documents described above to the CBO for review and approval. In the next Monthly Compliance Report following the CBO's approval, the project owner shall submit a written statement certifying that the documents have been approved by the CBO.

CIVIL-2 The resident engineer shall, if appropriate, stop all earthwork and construction in the affected areas when the responsible geotechnical engineer or civil engineer experienced and knowledgeable in the practice of soils engineering identifies unforeseen adverse soil or geologic conditions. The project owner shall submit modified plans, specifications, and calculations to the CBO based on these new conditions. The project owner shall obtain approval from the CBO before resuming earthwork and construction in the affected area. [1998 CBC, Section 104.2.4 – Stop orders.]

Verification: The project owner shall notify the CPM, within five (5) days, when earthwork and construction is stopped as a result of unforeseen adverse geologic/soil conditions. Within five (5) days of the CBO's approval, the project owner shall provide to the CPM a copy of the CBO's approval to resume earthwork and construction in the affected areas.

CIVIL-3 The project owner shall perform inspections in accordance with the 1998 CBC, Section 108 – Inspections, Chapter 17, Section 1701.6 – Continuous and periodic special inspection and Appendix Chapter 33, Section 3317 – Grading inspection. All plant site-grading operations shall be subject to inspection by the CBO and the CPM.

If, in the course of inspection, it is discovered that the work is not being done in accordance with the approved plans, the discrepancies shall be reported immediately to the resident engineer, the CBO, and the CPM. The project owner shall prepare a written report detailing all discrepancies and non-compliance items, and the proposed corrective action, and send copies to the CBO and the CPM.

Verification: Within five (5) days of the discovery of any discrepancies, the resident engineer shall transmit to the CBO and the CPM a non-conformance report (NCR), and the proposed corrective action. Within five (5) days of resolution of the NCR, the project owner shall submit the details of the corrective action to the CBO and the CPM. A list of NCRs for the reporting month shall also be included in the following Monthly Compliance Report.

CIVIL-4 After completion of finished grading and erosion and sedimentation control and drainage facilities, the project owner shall obtain the CBO's approval of the final "as-graded" grading plans and final "as-built" plans for the erosion and sedimentation control facilities. [1998 CBC, Section 109 – Certificate of Occupancy.]

Verification: Within thirty (30) days (or a lesser number of days mutually agreed to by the project owner and the CBO) of the completion of the erosion and sedimentation control mitigation and drainage facilities, the project owner shall submit to the CBO the responsible civil engineer's signed statement that the installation of the facilities and all erosion control measures were completed in accordance with the final approved combined grading plans, and that the facilities are adequate for their intended purposes. The project owner shall submit a copy of this report to the CPM in the next Monthly Compliance Report.

STRUC-1 Prior to the start of any increment of construction, the project owner shall submit to the CBO for review and approval the applicable designs, plans, and drawings, and a list of those project structures, components, and major equipment items that will undergo dynamic structural analysis. Designs, plans, and drawings shall be those for:

1. major project structures;

2. major foundations, equipment supports, and anchorages;

3. large field fabricated tanks;

4. turbine/generator pedestals; and

5. switchyard structures.

<u>Protocol:</u> The project owner shall:

1. obtain agreement with the CBO on the list of those structures, components, and major equipment items to undergo dynamic structural analysis;

2. meet the pile design requirements of the 1998 CBC. Specifically, Section 1807 – General Requirements, Section 1808 – Specific Pile Requirements, and Section 1809 – Foundation Construction (in seismic zones 3 and 4);

3. obtain approval from the CBO for the final design plans, specifications, calculations, soils reports, and applicable quality control procedures. If there are conflicting requirements, the more stringent shall govern (i.e., highest loads, or lowest allowable stresses shall govern). All plans, calculations, and specifications for foundations that support structures shall be filed concurrently with the structure plans, calculations, and specifications [1998 CBC, Section 108.4 – Approval Required];

4. submit to the CBO the required number of copies of the structural plans, specifications, calculations, and other required documents of the designated major structures at least ninety (90) days prior to the start of on-site fabrication and installation of each structure, equipment support, or foundation [1998 CBC, Section 106.4.2 – Retention of plans and Section 106.3.2 – Submittal documents.]; and

5. ensure that the final plans, calculations, and specifications clearly reflect the inclusion of approved criteria, assumptions, and methods used to develop the design. The final designs, plans, calculations, and specifications shall be signed and stamped by the responsible design engineer. [1998 CBC, Section 106.3.4 – Architect or engineer of record.]

<u>Verification:</u> At least thirty (30) days (or a lesser number of days mutually agreed to by the project owner and the CBO) prior to the start of any increment of construction, the project owner shall submit to the CBO, with a copy to the CPM, the responsible design engineer's signed statement that the final design plans, specifications, and calculations conform with all of the requirements set forth in the Commission's Decision.

If the CBO discovers non-conformance with the stated requirements, the project owner shall resubmit the corrected plans to the CBO within twenty (20) days of receipt of the nonconforming submittal, with a copy of the transmittal letter to the CPM.

The project owner shall submit to the CPM a copy of a statement from the CBO that the proposed structural plans, specifications, and calculations have been approved and are in conformance with the requirements set forth in the applicable LORS.

STRUC-2 The project owner shall submit to the CBO the required number of sets of the following:

1. concrete cylinder strength test reports (including date of testing, date sample taken, design concrete strength, tested cylinder strength, age of test, type and size of sample, location and quantity of concrete placement from which sample was taken, and mix design designation and parameters);

2. concrete pour sign-off sheets;

3. bolt torque inspection reports (including location of test, date, bolt size, and recorded torques);

4. field weld inspection reports (including type of weld, location of weld, inspection of non-destructive testing (NDT) procedure and results, welder qualifications, certifications, qualified procedure description or number [ref: AWS]; and

5. reports covering other structure activities requiring special inspections shall be in accordance with the 1998 CBC, Chapter 17, Section 1701 – Special Inspections, Section 1701.5 – Type of Work (requiring special inspection), Section 1702 – Structural Observation and Section 1703 – Nondestructive Testing.

Verification: If a discrepancy is discovered in any of the above data the project owner shall, within five (5) days, prepare and submit an NCR describing the nature of the discrepancies to the CBO, with a copy of the transmittal letter to the CPM. The NCR shall reference the Condition(s) of Certification and applicable CBC chapter and section. Within five (5) days of resolution of the NCR, the project owner shall submit a copy of the corrective action to the CBO and the CPM.

The project owner shall transmit a copy of the CBO's approval or disapproval of the corrective action to the CPM within fifteen (15) days. If disapproved, the project owner shall advise the CPM, within five (5) days, of the reason for disapproval and the revised corrective action necessary to obtain CBO's approval.

STRUC-3 The project owner shall submit to the CBO design changes to the final plans required by the 1998 CBC, Chapter 1, Section 106.3.2 – Submittal documents, and Section 106.3.3 – Information on plans and specifications, including the revised drawings, specifications, calculations, and a complete description of, and supporting rationale for, the proposed changes, and shall give the CBO prior notice of the intended filing.

Verification: On a schedule suitable to the CBO, the project owner shall notify the CBO of the intended filing of design changes, and shall submit the required number of sets of revised drawings and the required number of copies of the other above-mentioned documents to the CBO, with a copy of the transmittal letter to the CPM. The project owner shall notify the CPM, via the Monthly Compliance Report, when the CBO has approved the revised plans.

STRUC-4 Tanks and vessels containing quantities of toxic or hazardous materials exceeding amounts specified in Chapter 3, Table 3-E of the 1998 California Building Code (CBC) shall, at a minimum, be designed to comply with Occupancy Category 2 of the 1998 CBC. Chapter 16, Table 16–K of the 1998 CBC requires use of the following seismic design criteria: $I = 1.25$, $I_p=1.5$ and $I_w=1.15$.

Verification: At least thirty (30) days (or a lesser number of days mutually agreed to by the project owner and the CBO) prior to the start of installation of the tanks or vessels containing the above specified quantities of highly toxic or explosive substances that would be hazardous to the safety of the general public if released, the project owner shall submit to the CBO for review and approval final design plans, specifications, and calculations, including a copy of the signed and stamped engineer's certification.

The project owner shall send copies of the CBO approvals of plan checks to the CPM in the following Monthly Compliance Report. The project owner shall also transmit a copy of the CBO's inspection approvals to the CPM in the Monthly Compliance Report following completion of any inspection.

MECH-1 Prior to the start of any increment of piping construction, the project owner shall submit, for CBO review and approval, the proposed final design drawings, specifications, and calculations for each plant piping system (exclude: domestic water, refrigeration systems, and small bore piping, i.e., piping and tubing with a diameter equal to or less than two and one-half inches). The submittal shall also include the applicable Quality Assurance/Quality Control (QA/QC) procedures. The project owner shall design and install all piping, other than domestic water, refrigeration, and small bore piping to the applicable edition of the CBC. Upon completion of construction of any piping system, the project owner shall request the CBO's inspection approval of said construction. [1998 CBC, Section 106.3.2 – Submittal documents, Section 108.3 – Inspection Requests.]

Protocol: The responsible mechanical engineer shall submit a signed and stamped statement to the CBO when: 1)the proposed final design plans, specifications, and calculations conform with all of the piping requirements set forth in the Commission Decision; and 2) all of the other piping systems, except domestic water, refrigeration systems, and small bore piping, have been designed, fabricated, and installed in accordance with all applicable ordinances, regulations, laws and industry standards, including, as applicable:

American National Standards Institute (ANSI) B31.1 (Power Piping Code);
ANSI B31.2 (Fuel Gas Piping Code);
ANSI B31.3 (Chemical Plant and Petroleum Refinery Piping Code);
ANSI B31.8 (Gas Transmission and Distribution Piping Code); and
Specific City/County code.

The CBO may require the project owner, as necessary, to employ special inspectors to report directly to the CBO to monitor shop fabrication or equipment installation. [1998 CBC, Section 104.2.2 – Deputies.]

Verification: At least thirty (30) days (or a lesser number of days mutually agreed to by the project owner and the CBO) prior to the start of any increment of piping construction, the project owner shall submit to the CBO for approval, with a copy of the transmittal letter to the CPM, the proposed final design plans, specifications, calculations, and quality control procedures for that increment of construction of piping systems, including a copy of the signed and stamped engineer's certification of conformance with the Commission Decision. The project owner shall transmit a copy of the CBO's inspection approvals to the CPM in the Monthly Compliance Report following completion of any inspection.

MECH-2 For all pressure vessels installed in the plant, the project owner shall submit to the CBO and California Occupational Safety and Health Administration (Cal-OSHA), prior to operation, the code certification papers and other documents required by the applicable LORS. Upon completion of the installation of any pressure vessel, the project owner shall request the appropriate CBO and/or Cal-OSHA inspection of said installation. [1998 CBC, Section 108.3 – Inspection Requests.]

The project owner shall:

1. ensure that all boilers and fired and unfired pressure vessels are designed, fabricated, and installed in accordance with the appropriate section of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, or other applicable code. Vendor certification, with identification of applicable code, shall be submitted for prefabricated vessels and tanks; and

2. have the responsible design engineer submit a statement to the CBO that the proposed final design plans, specifications, and calculations conform to all of the requirements set forth in the appropriate ASME Boiler and Pressure Vessel Code or other applicable codes.

Verification: At least thirty (30) days (or a lesser number of days mutually agreed to by the project owner and the CBO) prior to the start of on-site fabrication or installation of any pressure vessel, the project owner shall submit to the CBO for review and approval final design plans, specifications, and calculations, including a copy of the signed and stamped engineer's certification, with a copy of the transmittal letter to the CPM.

The project owner shall send copies of the CBO plan check approvals to the CPM in the following Monthly Compliance Report. The project owner shall also transmit a copy of the CBO's and/or Cal-OSHA inspection approvals to the CPM in the Monthly Compliance Report following completion of any inspection.

MECH-3 Prior to the start of construction of any heating, ventilating, air conditioning (HVAC), or refrigeration system, the project owner shall submit to the CBO for review and approval the design plans, specifications, calculations, and quality control procedures for that system. Packaged HVAC systems, where used, shall be identified with the appropriate manufacturer's data sheets.

Verification: The project owner shall design and install all HVAC and refrigeration systems within buildings and related structures in accordance with the applicable edition of the CBC. Upon completion of any increment of construction, the project owner shall request the CBO's inspection and approval of said construction. The final plans, specifications, and calculations shall include approved criteria, assumptions, and methods used to develop the design. In addition, the responsible mechanical engineer shall sign and stamp all plans, drawings, and calculations and submit a signed statement to the CBO that the proposed final design plans, specifications, and calculations conform with the applicable LORS. [1998 CBC, Section 108.7 Other Inspections; Section 106.3.4 – Architect or engineer of record.]

At least thirty (30) days (or a lesser number of days mutually agreed to by the project owner and the CBO) prior to the start of construction of any HVAC or refrigeration system, the project owner shall submit to the CBO the required HVAC and refrigeration calculations, plans, and specifications, including a copy of the signed and stamped statement from the responsible mechanical engineer certifying compliance with the applicable edition of the CBC, with a copy of the transmittal letter to the CPM.

The project owner shall send copies of CBO comments and approvals to the CPM in the next Monthly Compliance Report. The project owner shall transmit a copy of the CBO's inspection approvals to the CPM in the Monthly Compliance Report following completion of any inspection.

MECH-4 Prior to the start of each increment of plumbing construction, the project owner shall submit for the CBO's approval the final design plans, specifications, calculations, and QA/QC procedures for all plumbing systems, potable water systems, drainage systems (including sanitary drain and waste), toilet rooms, building energy conservation systems, and temperature control and ventilation systems, including water and sewer connection permits issued by the local agency. Upon completion of any increment of construction, the project owner shall request the CBO's inspection approval of said construction. [1998 CBC, Section 108.3 – Inspection Requests, Section 108.4 – Approval Required.]

The project owner shall design, fabricate, and install:

1. plumbing, potable water, all drainage systems, and toilet rooms in accordance with Title 24, California Code of Regulations, Division 5, Part 5, and the California Plumbing Code (or other relevant section(s) of the

currently adopted California Plumbing Code and Title 24, California Code of Regulations); and

2. building energy conservation systems and temperature control and ventilation systems in accordance with Title 24, California Code of Regulations, Division 5, Chapter 2-53, Part 2.

The final plans, specifications, and calculations shall clearly reflect the inclusion of approved criteria, assumptions, and methods used to develop the design. In addition, the responsible mechanical engineer shall stamp and sign all plans, drawings, and calculations and submit a signed statement to the CBO that the proposed final design plans, specifications, and calculations conform with all of the requirements set forth in the Commission Decision.

Verification: At least thirty (30) days (or a lesser number of days mutually agreed to by the project owner and the CBO) prior to the start of construction of any of the above systems, the project owner shall submit to the CBO the final design plans, specifications, and calculations, including a copy of the signed and stamped statement from the responsible mechanical engineer certifying compliance with the applicable edition of the CBC, and send the CPM a copy of the transmittal letter in the next Monthly Compliance Report.

The project owner shall transmit a copy of the CBO's inspection approvals to the CPM in the next Monthly Compliance Report following completion of that increment of construction.

ELEC-1 For the 13.8 kV and lower systems, the project owner shall not begin any increment of electrical construction until plans for that increment have been approved by the CBO. These plans, together with design changes and design change notices, shall remain on the site for one year after completion of construction. The project owner shall request that the CBO inspect the installation to ensure compliance with the requirements of applicable LORS. [1998 CBC, Section 108.4 – Approval Required, and Section 108.3 – Inspection Requests.]

Protocol: The following activities shall be reported in the Monthly Compliance Report:

1. receipt or delay of major electrical equipment;

2. testing or energization of major electrical equipment; and

3. the number of electrical drawings approved, submitted for approval, and still to be submitted.

Verification: At least thirty (30) days (or a lesser number of days mutually agreed to by the project owner and the CBO) prior to the start of each increment of electrical construction, the project owner shall submit to the CBO for review and approval the final design plans, specifications, and calculations, including a copy of the signed and stamped statement from the responsible electrical engineer attesting to compliance with the applicable LORS, and send the CPM a copy of the transmittal letter in the next Monthly Compliance Report.

ELEC-2 The project owner shall submit to the CBO the required number of copies of items A and B for review and approval and one copy of item C: [CBC 1998, Section 106.3.2 – Submittal documents.]

A. Final plant design plans to include:

1. one-line diagrams for the 13.8 kV, 4.16 kV and 480 V systems;
2. system grounding drawings;
3. general arrangement or conduit drawings; and
4. other plans as required by the CBO.

B. Final plant calculations to establish:

1. short-circuit ratings of plant equipment;
2. ampacity of feeder cables;
3. voltage drop in feeder cables;
4. system grounding requirements;
5. coordination study calculations for fuses, circuit breakers and protective relay settings for the 13.8 kV, 4.16 kV and 480 V systems;
6. system grounding requirements;
7. lighting energy calculations; and
8. other reasonable calculations as customarily required by the CBO.

C. A signed statement by the registered electrical engineer certifying that the proposed final design plans and specifications conform to requirements set forth in the Commission Decision.

Verification: At least thirty (30) days (or a lesser number of days mutually agreed to by the project owner and the CBO) prior to the start of each increment of electrical equipment installation, the project owner shall submit to the CBO for review and approval the final design plans, specifications, and calculations for the items enumerated above, including a copy of the signed and stamped statement from the responsible electrical engineer certifying compliance with the applicable LORS. The project owner shall send the CPM a copy of the transmittal letter in the next Monthly Compliance Report.

Attachment 14 – Title V Permit (2017): Excerpted Detailed Summary of Facility Permits

Complete document available at http://www.valleyair.org/notices/Docs/2017/11-06-17_(S-1162576)/S-1162576.pdf

Initial Brief of the

California Independent System Operator Corporation

PG&E – La Paloma Unexecuted LGIA

ER21-2592

February 13, 2023

NOV 0 7 2017

Mr. James Maiz
La Paloma Generating Plant
PO Box 175
McKittrick, CA 93251-0175

Re: Notice of Preliminary Decision – Title V Permit Renewal
District Facility # S-3412
Project # S-1162576

Dear Mr. Maiz:

Enclosed for your review and comment is the District's analysis of the application to renew the Federally Mandated Operating Permit for La Paloma Generating Plant at 1760 W. Skyline Road, McKittrick, California.

The notice of preliminary decision for this project will be published approximately three days from the date of this letter. After addressing all comments made during the 30-day public notice and the 45-day EPA comment periods, the District intends to issue the renewed Federally Mandated Operating Permit. Please submit your written comments on this project within the 30-day public comment period, as specified in the enclosed public notice.

Thank you for your cooperation in this matter. If you have any questions, please contact Mr. Leonard Scandura, Permit Services Manager, at (661) 392-5500.

Sincerely,

Arnaud Marjollet
Director of Permit Services

Enclosures

cc: Tung Le, CARB (w/enclosure) via email
cc: Gerardo C. Rios, EPA (w/enclosure) via email

ATTACHMENT C

Detailed Summary List of Facility Permits

SJVUAPCD
SOUTHERN

Detailed Facility Report

For Facility=3412 and excluding Deleted Permits
Sorted by Facility Name and Permit Number

10/23/17
3:30 pm

LA PALOMA GENERATING CO LLC	FAC #: S 3412	TYPE: TitleV	EXPIRE ON: 01/31/2017
1760 W SKYLINE RD	STATUS: A	TOXIC ID: 60303	AREA: 3 /
MCKITTRICK, CA 93251	TELEPHONE: 6617626005		INSP. DATE: 06/18

PERMIT NUMBER	FEE DESCRIPTION	FEE RULE	QTY	FEE AMOUNT	FEE TOTAL	PERMIT STATUS	EQUIPMENT DESCRIPTION
S-3412-1-18	262,000 KW Power generation unit	3020-08B H	1	14,452.00	14,452.00	A	ABB GT-24 NATURAL GAS FIRED COMBINED CYCLE GAS TURBINE ENGINE/ELECTRICAL GENERATOR #1 WITH INLET FOGGERS, DRY LOW NOX COMBUSTORS, STEAM POWER AUGMENTATION, SELECTIVE CATALYTIC REDUCTION, STEAM TURBINE, AND ELECTRICAL GENERATOR (262 MW NOMINAL RATING)
S-3412-2-19	262,000 KW Power generation unit	3020-08B H	1	14,452.00	14,452.00	A	ABB GT-24 NATURAL GAS FIRED COMBINED CYCLE GAS TURBINE ENGINE/ELECTRICAL GENERATOR #2 WITH INLET FOGGERS, DRY LOW NOX COMBUSTORS, STEAM POWER AUGMENTATION, SELECTIVE CATALYTIC REDUCTION, STEAM TURBINE AND ELECTRICAL GENERATOR (262 MW NOMINAL RATING)
S-3412-3-19	262,000 KW Power generation unit	3020-08B H	1	14,452.00	14,452.00	A	ABB GT-24 NATURAL GAS FIRED COMBINED CYCLE GAS TURBINE ENGINE/ELECTRICAL GENERATOR #3 WITH INLET FOGGERS, DRY LOW NOX COMBUSTORS, STEAM POWER AUGMENTATION, SELECTIVE CATALYTIC REDUCTION, STEAM TURBINE, AND ELECTRICAL GENERATOR (262 MW NOMINAL RATING)
S-3412-4-14	262,000 KW Power generation unit	3020-08B H	1	14,452.00	14,452.00	A	ABB GT-24 NATURAL GAS FIRED COMBINED CYCLE GAS TURBINE ENGINE/ELECTRICAL GENERATOR #4 WITH INLET FOGGERS, DRY LOW NOX COMBUSTORS, STEAM POWER AUGMENTATION, OXIDATION CATALYST, SELECTIVE CATALYTIC REDUCTION, STEAM TURBINE, AND ELECTRICAL GENERATOR (262 MW NOMINAL RATING)
S-3412-5-4	part of ele gen process	999-99	1	0.00	0.00	A	COOLING TOWER #1 WITH 8 CELLS AND HIGH EFFICIENCY DRIFT ELIMINATOR
S-3412-6-4	part of ele gen process	999-99	1	0.00	0.00	A	COOLING TOWER #2 WITH 8 CELLS AND HIGH EFFICIENCY DRIFT ELIMINATOR
S-3412-8-4	no applicable fee	999-99	1	0.00	0.00	A	587 BHP CATERPILLAR MODEL #3406 DIESEL-FIRED EMERGENCY STANDBY IC ENGINE POWERING AN ELECTRICAL GENERATOR (#1)
S-3412-9-4	no applicable fee	999-99	1	0.00	0.00	A	587 BHP CATERPILLAR MODEL #3406 DIESEL-FIRED EMERGENCY STANDBY IC ENGINE POWERING AN ELECTRICAL GENERATOR (#2)
S-3412-10-4	no applicable fee	999-99	1	0.00	0.00	A	587 BHP CATERPILLAR MODEL #3406 DIESEL-FIRED EMERGENCY STANDBY IC ENGINE POWERING AN ELECTRICAL GENERATOR (#3)
S-3412-11-4	no applicable fee	999-99	1	0.00	0.00	A	587 BHP CATERPILLAR MODEL #3406 DIESEL-FIRED EMERGENCY STANDBY IC ENGINE POWERING AN ELECTRICAL GENERATOR (#4)
S-3412-13-2	no applicable fee	999-99	1	0.00	0.00	A	6.4 MMBTU/HR CLAYTON MODEL EG-154-1 LNB NATURAL GAS FIRED BOILER
S-3412-14-4	240 bhp IC engine	3020-10 C	1	264.00	264.00	A	240 BHP CLARKE-DETROIT DIESEL-ALLISON MODEL #JU6H-UF60 DIESEL-FIRED EMERGENCY IC ENGINE POWERING A FIREWATER PUMP

Number of Facilities Reported: 1

Attachment 15 – Environmental Protection Agency Injection Control Permit Fact Sheet

Initial Brief of the

California Independent System Operator Corporation

PG&E – La Paloma Unexecuted LGIA

ER21-2592

February 13, 2023

FACT SHEET

U.S. Environmental Protection Agency, Region 9 Draft Class I Underground Injection Control Permit # CA10710001
To La Paloma Generating Company, LLC

Location:
La Paloma Generating Company, LLC
1760 W. Skyline Road, P.O. Box 175
McKittrick, CA 93251

Permittee Contact:
Mr. Nick Park, Plant Manager
La Paloma Generating Company, LLC
1760 W. Skyline Road, P.O. Box 175
McKittrick, CA 93251
Plant phone: (661) 762-6000

Regulatory Contact:
Adam Freedman, Environmental Scientist
U.S. Environmental Protection Agency, Region 9
Ground Water Office, Mail Code WTR-9
75 Hawthorne Street
San Francisco, CA 94105-3901
Telephone: (415) 972-3845
Fax: (415) 972-3545 (include name and mail code from above)
Email: freedman.adam@epa.gov

I. Purpose of the Fact Sheet

Pursuant to the Underground Injection Control (UIC) regulations in Title 40 of the Code of Federal Regulations (CFR), §124.8, the purpose of this fact sheet is to briefly describe the principal facts and the considerations that went into preparing the draft permit. To meet these objectives, this fact sheet contains background information on the permit process, a description of the facility, a brief discussion of the permit conditions, and the reasons for these permit conditions.

II. Permit Process

Application and Review Period

The U.S. Environmental Protection Agency, Region 9 (EPA) Director has authority to issue permits for underground injection activities under 40 CFR §144.31. La Paloma Generating Company, LLC (LPGC) is applying for a UIC permit renewal (of permit #CA199000001) to operate a Class I injection well facility to dispose of non-hazardous wastewater from the La Paloma Generating Plant. EPA received an individual permit application dated March 28, 2007, for between three (3) and five (5) Class I nonhazardous UIC wells from LPGC. In a letter to LPGC dated April 30, 2007, EPA confirmed that the application was administratively complete. Following this, EPA began the technical review. Following a thorough technical review, EPA determined that the information provided was sufficient to complete a draft UIC permit. EPA has now completed a draft Class I nonhazardous UIC permit that would authorize the construction of up to five (5) injection wells in total. The draft permit contains numerous construction, operation, maintenance, monitoring, reporting, and abandonment requirements.

Based on our review of the proposed well construction, operation standards, monitoring requirements, and the existing geologic setting, EPA believes the activities allowed under the proposed draft permit are protective of Underground Sources of Drinking Water as required under the Safe Drinking Water Act.

Public Participation

The public has thirty (30) days to review and comment on the Class I UIC draft permit (40 CFR §124.10). The draft permit and this fact sheet are available at the following locations:

Kern County Library
701 Truxtun Avenue
Bakersfield, CA 93301

U.S. Environmental Protection Agency, Region 9
Ground Water Office
Attn: Adam Freedman, Mail Code WTR-9
75 Hawthorne Street
San Francisco, CA 94105

The draft permit and fact sheet are also available at the EPA Region 9 web page:
http://www.epa.gov/region09/water/groundwater/uic-permits.html

The public comment period begins on February 3, 2008 and ends on March 4, 2008. During this period, all written comments on the draft permit can be sent, faxed, or e-mailed to Adam Freedman using the contact information listed on the first page of this fact sheet. Adam Freedman is also available by phone for any questions regarding the draft permit.

All persons, including the applicant, who object to any condition of the draft permit or EPA's decision to prepare a draft permit must raise all reasonably ascertainable issues and submit all reasonable arguments supporting their position by the close of the comment period (40 CFR §124.13). The public comment period may be reopened if this could expedite decision making (40 CFR §124.13). If requested, a public hearing may be held (40 CFR §§124.11 and 124.12).

Final Decision Making Process

After the close of the public comment period, EPA will review and consider all comments relevant to the UIC permit and application. A response to comments will be sent to the applicant and each person who has submitted written comments or requested notice of the final permit decision and posted on the EPA website. The response to comments will contain: a response to all significant comments on the draft permit; EPA's final decision; any permit conditions that are changed and the reasons for the changes; and procedures for appealing the decision. The final decision shall be to either issue or deny the permit. The final decision shall become effective no sooner than thirty (30) days after the service of the notice of decision. Within thirty (30) days after the final permit decision has been issued, any person who filed comments on the draft permit, participated in any Public Hearing on this matter, or takes issue with any changes in the draft permit, may petition the Environmental Appeals Board to review any condition of the permit decision. Commenters are referred to 40 CFR §124.19 for procedural requirements of the appeal process. If no comments request a change in the draft permit, the permit shall become effective immediately upon issuance (40 CFR §124.15).

III. Description of the Facility

The La Paloma Generating Plant (LPGP) began commercial operation in March 2003. The facility consists of a 1,022 MW combined cycle, natural gas-fired electrical power plant. The combined cycle power block consists of four combustion turbine generators, and four heat recovery steam generators. The facility area is approximately 400 acres.

LPGP currently utilizes a zero liquid discharge (ZD) system to treat and dispose of wastewater. The construction of the ZD system followed EPA's denial of authorization for LPGC to inject into the previously proposed injection zone, which EPA determined to be an underground source of drinking water (USDW). LPGP has experienced difficulties processing the large volume of wastewater generated by the facility and has experienced ongoing mechanical and corrosion-related material failures in the ZD system resulting in a high level of maintenance. These challenges have caused unplanned outages of electrical generation and prompted significant brine disposal practices at landfills.

Wastewater from the LPGP consists primarily of cooling tower blowdown from the power plant cooling process with lesser volumes of boiler and evaporative cooler blowdown, wash water, filter backwash, equipment drains, and stormwater from equipment containment areas at the generating plant. According to LPGC's proposed design, before final discharge to the UIC disposal well, wastewater will continue to pass through the filtration portion (multi-media filters and reverse osmosis system) of the ZD wastewater treatment system. The filtrate will then be pumped into the UIC disposal well. Pretreatment of both wastewater and raw water will effectively remove solids that could otherwise plug the injection zone.

LPGC has applied for a permit to allow well construction and operation at an injection rate of 2,126 barrels per day (bbl/day) in each of 5 wells or 3,543 bbl/day in each of 3 wells, resulting in an anticipated average injection rate of 10,600 barrels of wastewater per day, or 0.45 million gallons per day (mgd). The maximum anticipated injection rate is 19,400 bbl/day, or 0.81 mgd, which is estimated to occur no more than 14 days per operating year. All potential injection wells will be located on property near LPGC's facility on W. Skyline Road in McKittrick, California.

IV. Brief Summary of Specific Permit Conditions

In order to protect public health and the environment, the following conditions for injection well construction, corrective action, operation, monitoring and reporting, plugging and abandonment, and financial responsibility have been included in the La Paloma Generating Company, LLC Draft Class I UIC Permit:

Well Construction (Part II, Section A of the Draft Permit)

No injection well drilling, testing, construction, or operation may commence without prior written approval from EPA. Well design specifications include a Conductor casing (14-16 inch diameter) to approximately 40 feet below ground surface, Surface casing (9-5/8 inch diameter) from ground surface to approximately 500 ft bgs, Long String casing (7 inch diameter) from ground surface to approximately 4,400 feet below ground surface to the top of the target Miocene Olig sand injection zone of the Reef Ridge Formation, and tubing (5-inch diameter) from the surface to approximately 4,228 ft bgs. The conductor pipe, surface casing, and long string casing are all designed to be cemented to the surface. The injection apparatus additionally includes the installation of a 5.0 inch liner. Complete well schematics are included in Appendix B of the draft permit.

EPA will require logs and other tests to be conducted during drilling and construction that shall include, at a minimum, deviation checks, casing logs, and injection formation tests. Before surface, intermediate, and long string casings are set, a dual induction/spontaneous potential/gamma ray log will be run over the course of the entire open hole sequence after the well is drilled to each respective terminal depth. After each casing is set and cementing complete, a spherically focused cement bond evaluation log will be run over the course of the entire cased hole sequence. EPA will require mechanical integrity testing after completion and regularly while operating, to ensure that injection fluid is properly contained.

EPA will require injection formation information to be determined through well logs and tests and shall include a characterization of porosity, permeability, static formation pressure, and effective thickness of the injection zone. A fall-off pressure test (FOT) will be conducted six months after the start of injection and annually thereafter to determine and monitor formation characteristics. A step-rate test (SRT) will be conducted on at least one representative well before injection is authorized, to establish maximum injection pressure.

Groundwater testing at well sites will be required during construction of the wells and shall include well logs and Total Dissolved Solids (TDS) analysis of target formation water to demonstrate either the presence and characteristics of, or the lack of, any Underground Sources of Drinking Water (USDWs). Formation water samples from the injection zone will be collected for subsequent analyses from the first injection well upon its completion to confirm that representative Olig formation water is being collected.

Corrective Action (Part II, Section B of the Draft Permit)

The applicant completed preliminary calculations of the Zone of Endangering Influence (ZEI), based on reasonable assumptions and EPA has confirmed that these appear to be within the half-mile Area of Review (AOR). After assumptions are confirmed or replaced by field test data obtained through hydrogeologic testing required under the proposed permit, the ZEI will be recalculated annually, and if the recalculated ZEI extends beyond the AOR, corrective action may be required. Corrective action may include, but is not limited to reentering, plugging, and abandoning any production or exploratory wells which penetrate the injection zone and are located within the permit's AOR.

Well Operation (Part II, Section C of the Draft Permit)

Prior to receiving authorization to inject, LPGC will conduct mechanical integrity (MI) testing, step-rate testing, injection zone parameter testing, a hazardous waste determination of the injectate, and ground water sampling. No hazardous waste may be injected into any of the proposed injection wells. Maximum allowable injectate volume and pressure limitations are subject to results of testing required under the permit. The permit requires annual mechanical integrity and pressure transient testing to ensure protection of underground sources of drinking water. Mechanical integrity must be demonstrated by means of an annular pressure test in the tubing/casing annulus, an evaluation of cement integrity in the casing/borehole annulus and sufficient results from temperature logs and radioactive tracer testing. Formation pressure data will be measured and monitored annually to ensure that pressure buildup is limited to the AOR.

The injection well will be operated so as to not initiate or propagate fractures in the injection formation. A maximum surface injection pressure (pumping pressure) will be calculated based on formation test data.

Monitoring, Record Keeping, and Reporting (Part II, Section D of the Draft Permit)

LPGC is required to continuously monitor injection rate, total injection volume, injection pressure, annular pressure, and injection fluid temperature. LPGC is required to sample the injectate on a quarterly basis to determine the following: Inorganics (Major Anions and Cations); Solids (Total Dissolved Solids and for Total Suspended Solids); General and Physical Parameters (Turbidity, pH, Conductivity, Hardness, Specific Gravity, Alkalinity, Biological Oxygen Demand (BOD), Density and Viscosity); Trace Metals; Volatile Organic Compounds (VOCs); and Semi-VOCs.

All sampling analyses must be performed at a laboratory approved by EPA. LPGC is required to maintain all operational and monitoring records, and to submit quarterly summary reports to EPA.

Well Plugging and Abandonment (Part II, Section E of the Draft Permit)

Upon determination that any injection well regulated by this permit is to be permanently abandoned, LPGC would be required to abandon the injection well according to the Plugging and Abandonment Plans in Appendix E of the draft permit. EPA reserves the right to change the manner in which a well will be plugged if the well is modified during its permitted life or if the well is not consistent with EPA requirements for construction or mechanical integrity.

Financial Responsibility (Part II, Section F of the Draft Permit

Authority to drill and construct any well will not be granted until financial resources sufficient to properly close, plug, and abandon the well amounting to $127,000 per well are posted and approved by EPA. Failure to submit the required financial demonstration could result in the termination of the permit.

Duration of Permit (Part II, Section G of the Draft Permit)

The permit and the authorization to inject would be issued for a period of up to ten (10) years unless terminated under the conditions set forth in Part III, Section B.1 of the draft permit.

Attachment 16 – Motion for Joint Administration in 2018 Bankruptcy Proceeding

Initial Brief of the

California Independent System Operator Corporation

PG&E – La Paloma Unexecuted LGIA

ER21-2592

February 13, 2023

**IN THE UNITED STATES BANKRUPTCY COURT
FOR THE DISTRICT OF DELAWARE**

In re:	Chapter 11
LA PALOMA GENERATING COMPANY, LLC,	Case No. 16-__________ ( )
Debtor.	
Tax I.D. No. 52-2129359	

In re:	Chapter 11
LA PALOMA ACQUISITION CO, LLC,	Case No. 16-__________ ( )
Debtor.	
Tax I.D. No. 03-0562500	

In re:	Chapter 11
CEP LA PALOMA OPERATING COMPANY, LLC,	Case No. 16-__________ ( )
Debtor.	
Tax I.D. No. 03-0562503	

DEBTORS' MOTION FOR ENTRY OF AN ORDER
<u>DIRECTING JOINT ADMINISTRATION OF CHAPTER 11 CASES</u>

La Paloma Generating Company, LLC ("**La Paloma**") and its affiliated debtors and debtors in possession (collectively, the "**Debtors**")[1] respectfully request entry of an order directing joint administration of their chapter 11 cases for procedural purposes only and granting

[1] The Debtors in these cases, along with the last four digits of each Debtor's federal tax identification number, are La Paloma Generating Company, LLC (9359), La Paloma Acquisition Co, LLC (2500), and CEP La Paloma Operating Company, LLC (2503). The address of the Debtors' corporate headquarters is 1700 Pennsylvania Avenue, NW, Suite 800, Washington, DC 20006.

related relief. In support of this motion, the Debtors rely on and incorporate by reference *Niranjan Ravindran's Declaration in Support of the Debtors' Chapter 11 Petitions and First Day Pleadings* (the "**Ravindran Declaration**"), filed concurrently with this motion.[2] In further support of the motion, the Debtors, by and through their undersigned counsel, respectfully represent:

JURISDICTION AND VENUE

1. This Court has jurisdiction to consider this motion under 28 U.S.C. §§ 157 and 1334 and venue is proper under 28 U.S.C. §§ 1408 and 1409. This is a core proceeding under 28 U.S.C. § 157(b).[3]

BACKGROUND

2. On December 6, 2016 (the "**Petition Date**"), each of the Debtors filed a voluntary petition with this Court for relief under chapter 11 of the Bankruptcy Code. The Debtors manage and operate their business as debtors in possession under sections 1107(a) and 1108 of the Bankruptcy Code.

3. La Paloma owns a 1,022 MW (nameplate capacity) natural gas-fired, combined cycle generating facility consisting of four identical power blocks, located on an approximately 400-acre site in McKittrick, California (the "**Facility**"). Approximately 110 miles northwest of Los Angeles and 40 miles west of Bakersfield, the Facility is optimally located for maximizing power flows throughout northern and southern California. The Facility commenced operation in March 2003 and operates as a merchant facility selling capacity and power into the

[2] Capitalized terms used but not defined in this motion have the meanings used in the Ravindran Declaration.

[3] Pursuant to rule 9013-1(f) of the Local Rules of Bankruptcy Practice and Procedure of the United States Bankruptcy Court for the District of Delaware (the "**Local Rules**"), the Debtors hereby expressly confirm their consent to the entry of a final order by this Court in connection with this motion if it is later determined that this Court, absent consent of the parties, cannot enter final orders or judgments in connection therewith consistent with Article III of the United States Constitution.

California Independent System Operator market. CEP La Paloma Operating Company, LLC ("**CEP**") is the manager of La Paloma and its direct parent and sole member, La Paloma Acquisition Co, LLC ("**LPAC**"). As described in the Ravindran Declaration, CEP subcontracts its management responsibilities to various third parties.

4. Additional information on the Debtors' business and capital structure, as well as a description of the reasons for filing these cases is set forth in the Ravindran Declaration.

RELIEF REQUESTED

5. By this motion, pursuant to Bankruptcy Rule 1015(b) and Local Rule 1015-1, the Debtors request entry of an order, substantially in the form attached as Exhibit A, directing procedural consolidation and joint administration of these chapter 11 cases.

6. In addition, the Debtors request that the caption of their chapter 11 cases in all pleadings and notices in the jointly administered cases be as follows:

IN THE UNITED STATES BANKRUPTCY COURT
FOR THE DISTRICT OF DELAWARE

In re:	:	Chapter 11
LA PALOMA GENERATING COMPANY, LLC, *et al.*[1]	:	Case No. 16-__________ ( )
	:	Jointly Administered
Debtors.	:	

[1] The Debtors in these cases, along with the last four digits of each Debtor's federal tax identification number, are La Paloma Generating Company, LLC (9359), La Paloma Acquisition Co, LLC (2500), and CEP La Paloma Operating Company, LLC (2503). The address of the Debtors' corporate headquarters is 1700 Pennsylvania Avenue, NW, Suite 800, Washington, DC 20006.

7. The Debtors also seek waiver of the requirements of section 342(c)(1) of the Bankruptcy Code and Bankruptcy Rules 1005 and 2002(n) that the case caption on pleadings

and notices in these cases contain the name, tax identification number, and address of each Debtor and any names used by each Debtor in the previous eight years. As an alternative to including this information in each caption, the Debtors propose to include the following footnote to each pleading filed and notice mailed by the Debtors, listing the Debtors in these chapter 11 cases and the last four digits of their tax identification numbers along with the address of the Debtors' corporate headquarters:

> The Debtors in these cases, along with the last four digits of each Debtor's federal tax identification number, are La Paloma Generating Company, LLC (9359), La Paloma Acquisition Co, LLC (2500), and CEP La Paloma Operating Company, LLC (2503). The address of the Debtors' corporate headquarters is 1700 Pennsylvania Avenue, NW, Suite 800, Washington, DC 20006.

8. The Debtors also request that the Court make a separate docket entry in each of the Debtors' chapter 11 cases (except that of La Paloma), substantially similar to the following:

> An order has been entered in this case consolidating this case with the case of La Paloma Generating Company, LLC (Case No. 16-_______(___)) for procedural purposes only and providing for its joint administration in accordance with the terms thereof. The docket in Case No. 16-_______ (___) should be consulted for all matters affecting this case.

BASIS FOR RELIEF REQUESTED

9. Bankruptcy Rule 1015(b) provides, in relevant part, that "[i]f . . . two or more petitions are pending in the same court by or against . . . a debtor and an affiliate, the court may order a joint administration of the estates." Fed. R. Bankr. P. 1015(b). The Debtors are "affiliates" of each other as that term is defined in section 101(2) of the Bankruptcy Code, as Blocker (La Paloma), LLC (i) is the direct parent and sole member of CEP and (ii) holds approximately $52.3% of the membership interests in LPAC, which is the direct parent and sole

member of La Paloma. This Court thus is authorized to consolidate the Debtors' cases for procedural purposes.

10. Local Rule 1015-1 provides additional authority for the Court to order joint administration of these chapter 11 cases:

> An order of joint administration may be entered, without notice and an opportunity for hearing, upon the filing of a motion for joint administration pursuant to Fed. R. Bankr. P. 1015, supported by an affidavit, declaration or verification, which establishes that the joint administration of two or more cases pending in the Court under title 11 is warranted and will ease the administrative burden for the Court and the parties. An order of joint administration entered in accordance with this Local Rule may be reconsidered upon motion of any party in interest at any time. An order of joint administration under this Local Rule is for procedural purposes only and shall not cause a "substantive" consolidation of the respective debtors' estates.

Del. Bankr. L.R. 1015-1.

11. The Ravindran Declaration establishes that joint administration of the Debtors' cases is warranted because it will ease the administrative burden on the Court and all parties in interest. Joint administration of the Debtors' cases will eliminate the need for duplicate pleadings, notices, and orders in each of the respective dockets and will save the Court, the Debtors, and other parties in interest substantial time and expense when preparing and filing such documents. Further, joint administration will protect parties in interest by ensuring that they will be apprised of the various motions filed with the Court with respect to each of the Debtors' cases. Therefore, joint administration of the Debtors' cases is appropriate under Bankruptcy Rule 1015(b) and Local Rule 1015-1.

12. Joint administration will not adversely affect the Debtors' respective constituencies because this motion seeks only administrative, not substantive consolidation of the Debtors' estates. Parties in interest will not be harmed by the relief requested; instead, parties in

interest will benefit from the cost reductions associated with the joint administration of these chapter 11 cases. Accordingly, the Debtors submit that the joint administration of these chapter 11 cases is in the best interests of their estates, their creditors, and all other parties in interest.

13. Finally, the Debtors submit that use of the simplified caption, without reference to the Debtors' full tax identification numbers, addresses, and previous names, will eliminate cumbersome and confusing procedures and ensure uniformity of pleading identification. Other case-specific information will be listed in the petitions for the respective Debtors and such petitions are publicly available and will be provided by the Debtors upon request. Therefore, the Debtors submit the policies behind the requirements of section 342(c)(1) of the Bankruptcy Code and Bankruptcy Rules 1005 and 2002(n) have been fully satisfied.

14. Courts in this District have routinely granted relief similar to the relief requested in several other cases involving multiple related debtors.[4] For these reasons, the Debtors submit that the relief requested is necessary and appropriate, is in the best interest of their respective estates and creditors, and should be granted in all respects.

NOTICE

15. The Debtors will provide notice of this motion by facsimile, e-mail, overnight delivery, or hand delivery to: (i) the Office of the United States Trustee for the District of Delaware; (ii) the holders of the 30 largest unsecured claims against the Debtors on a

[4] *See, e.g., In re New Gulf Res., LLC*, Case No. 15-12566 (BLS) (Bankr. D. Del. Dec. 18, 2015) (D.I. 33); *In re Am. Apparel, Inc.*, Case No. 15-12055 (BLS) (Bankr. D. Del. Oct. 6, 2015) (D.I. 65); *In re Samson Res. Corp.*, Case No. 15-11934 (CSS) (Bankr. D. Del. Sept. 18, 2015) (D.I. 70); *In re Colt Holding Co. LLC*, Case No. 15-11296 (LSS) (Bankr. D. Del. June 16, 2015) (D.I. 69); *In re Corinthian Colleges, Inc.*, Case No. 15-10952 (KJC) (Bankr. D. Del. May 5, 2015) (D.I. 19); *In re Frederick's of Hollywood, Inc.*, Case No. 15-10836 (KG) (Bankr. D. Del. Apr. 21, 2015) (D.I. 48); *In re Allied Nevada Gold Corp.*, Case No. 15-10503 (MFW) (Bankr. D. Del. Mar. 11, 2015) (D.I. 53); *In re Cal Dive International, Inc.*, Case No. 15-10458 (CSS) (Bankr. D. Del. Mar. 6, 2015) (D.I. 57); *In re RadioShack Corporation*, No. 15-10197 (BLS) (Bankr. D. Del. Feb. 6, 2015) (D.I. 98); *In re Dendreon Corporation*, Case No. 14-12515 (LSS) (Walsh, J.) (Bankr. D. Del. Nov. 12, 2014) (D.I. 49).

consolidated basis; (iii) all agents and trustees under the Debtors' prepetition debt instruments; (iv) counsel to the agents and trustees under the Debtors' prepetition debt instruments; (v) the Internal Revenue Service; (vi) the Securities and Exchange Commission; and (vii) any other party entitled to notice pursuant to Local Rule 9013-1(m). Following the hearing, a copy of this motion and any order entered with respect to it will be served on the foregoing parties and all parties having filed requests for notice in these chapter 11 cases. A copy of the motion is also available on the Debtors' case website at http://dm.epiq11.com/lapaloma.

16. As this motion is seeking "first day" relief, notice of this motion and any order entered hereon will be served on all parties required by Local Rule 9013-1(m). Due to the urgency of the relief requested, the Debtors submit that no other or further notice is necessary.

NO PRIOR MOTION

17. The Debtors have not made any prior motion for the relief sought in this motion to this Court or any other.

The Debtors respectfully request entry of an order granting the relief requested in its entirety and any other relief as is just and proper.

Dated: December 6, 2016
Wilmington, Delaware

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Proposed Attorneys for the
Debtors and Debtors in Possession

Exhibit A

Proposed Order

IN THE UNITED STATES BANKRUPTCY COURT
FOR THE DISTRICT OF DELAWARE

In re:	Chapter 11
LA PALOMA GENERATING COMPANY, LLC,	Case No. 16-__________ ( )
Debtor.	
Tax I.D. No. 52-2129359	
In re:	Chapter 11
LA PALOMA ACQUISITION CO, LLC,	Case No. 16-__________ ( )
Debtor.	
Tax I.D. No. 03-0562500	
In re:	Chapter 11
CEP LA PALOMA OPERATING COMPANY, LLC,	Case No. 16-__________ ( )
Debtor.	
Tax I.D. No. 03-0562503	

ORDER DIRECTING JOINT
ADMINISTRATION OF CHAPTER 11 CASES

Upon the Debtors'[1] motion (the "**Motion**")[2] for entry of an order (this "**Order**") directing the Debtors' chapter 11 cases to be jointly administered for procedural purposes only

[1] The Debtors in these cases, along with the last four digits of each Debtor's federal tax identification number, are La Paloma Generating Company, LLC (9359), La Paloma Acquisition Co, LLC (2500), and CEP La Paloma Operating Company, LLC (2503). The address of the Debtors' corporate headquarters is 1700 Pennsylvania Avenue, NW, Suite 800, Washington, DC 20006.

[2] Capitalized terms used but not defined in this Order have the meanings used in the Motion.

and granting related relief, all as more fully set forth in the Motion; and due and sufficient notice of the Motion having been provided under the particular circumstances, and it appearing that no other or further notice need be provided; and the Court having jurisdiction to consider the Motion and the relief requested therein in accordance with 28 U.S.C. §§ 157 and 1334; and consideration of the Motion and the relief requested therein being a core proceeding under 28 U.S.C. § 157(b)(2); and this Court's entry of a final order being consistent with Article III of the United States Constitution; and venue being proper before this Court under 28 U.S.C. §§ 1408 and 1409; and a hearing having been held to consider the relief requested in the Motion (the "**Hearing**"); and upon the Ravindran Declaration and the record of the Hearing and all the proceedings had before the Court; and the Court having found and determined the relief requested in the Motion to be in the best interests of the Debtors, their estates and creditors, and any parties in interest; and the legal and factual bases set forth in the Motion and at the Hearing having established just cause for the relief granted herein; and after due deliberation thereon and sufficient cause appearing therefor, it is HEREBY ORDERED THAT:

1. The Motion is granted as set forth herein.

2. Each of the above-captioned chapter 11 cases of the Debtors are consolidated for procedural purposes only and shall be jointly administered by the Court under Case No. 16-__________ (____).

3. Nothing contained in the Motion or this Order is to be deemed or construed as directing or otherwise effecting a substantive consolidation of these chapter 11 cases.

4. The caption of the jointly administered cases shall read as follows:

IN THE UNITED STATES BANKRUPTCY COURT
FOR THE DISTRICT OF DELAWARE

In re:	Chapter 11
LA PALOMA GENERATING COMPANY, LLC, *et al.* [1]	Case No. 16-__________ ( )
Debtors.	Jointly Administered

[1] The Debtors in these cases, along with the last four digits of each Debtor's federal tax identification number, are La Paloma Generating Company, LLC (9359), La Paloma Acquisition Co, LLC (2500), and CEP La Paloma Operating Company, LLC (2503). The address of the Debtors' corporate headquarters is 1700 Pennsylvania Avenue, NW, Suite 800, Washington, DC 20006.

5. All pleadings and notices shall be captioned as indicated in the preceding decretal paragraph, and all original docket entries shall be made in the case of La Paloma Generating Company, LLC, Case No. 16-_______ (____).

6. A docket entry shall be made in each of the Debtors' cases (except that of La Paloma Generating Company, LLC) substantially similar to the following:

> An order has been entered in this case consolidating this case with the case of La Paloma Generating Company, LLC (Case No. 16-________(____)) for procedural purposes only and providing for its joint administration in accordance with the terms thereof. The docket in Case No. ________ (____) should be consulted for all matters affecting this case.

7. The Debtors are directed to include the following footnote to each pleading they file and notice they mail in these cases, listing the Debtors in these chapter 11 cases and the last four numbers of their tax identification numbers along with the address of the Debtors' corporate headquarters only:

> The Debtors in these cases, along with the last four digits of each Debtor's federal tax identification number, are La Paloma Generating Company, LLC (9359), La Paloma Acquisition Co, LLC (2500), and CEP La Paloma Operating Company, LLC

(2503). The address of the Debtors' corporate headquarters is 1700 Pennsylvania Avenue, NW, Suite 800, Washington, DC 20006.

8. The terms and conditions of this Order are immediately effective and enforceable upon its entry.

9. The Debtors are authorized and empowered to take all actions necessary or appropriate to implement the relief granted in this Order.

10. This Court retains jurisdiction over all matters arising from or related to the implementation or interpretation of this Order.

Dated: _______________, 2016
Wilmington, Delaware

____
UNITED STATES BANKRUPTCY JUDGE

Attachment 17 – La Paloma Bankruptcy Pre-Trial Brief

Initial Brief of the

California Independent System Operator Corporation

PG&E – La Paloma Unexecuted LGIA

ER21-2592

February 13, 2023

IN THE UNITED STATES BANKRUPTCY COURT
FOR THE DISTRICT OF DELAWARE

In re: LA PALOMA GENERATING COMPANY, LLC, *et al.*,[1] Debtors.	Chapter 11 Case No. 16-12700 (CSS) (Jointly Administered)

PRE-TRIAL BRIEF OF LAW OF LA PALOMA LIQUIDATING TRUST

Dated: January 26, 2018
Wilmington, Delaware

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[1] The Debtors in these cases, along with the last four digits of each Debtor's federal tax identification number are: La Paloma Generating Company, LLC (9359), La Paloma Acquisition Co, LLC (2500) and CEP La Paloma Operating Company, LLC (2503). The address of the Debtors' corporate headquarters is 1700 Pennsylvania Avenue, NW, Suite 800, Washington DC 20006.

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I. INTRODUCTION

The La Paloma Generating Facility is a combined-cycle gas turbine ("CCGT") electric generating plant located in the southern portion of Kern County, California (the "Facility"). The Facility became operational in 2003 as a "base load" facility intended to operate continuously pursuant to contracts that guaranteed above-market revenue sufficient to support construction.

Today, the Facility operates in a very different and less economic world than existed when it was conceived and built. The Facility is now a "load following" facility, meaning that it operates only periodically when pricing allows economic operation, without long term contracts for sale of electricity or capacity (although some of La Paloma's generation was subject to intermediate term "tolling contracts" and capacity contracts during some of the years at issue).[2]

The express policy of the State of California is to replace gas-fired generation with renewable (solar, hydro, wind and geothermal) energy sources. Assembly Bill 32 ("AB 32"), "The Global Warming Solutions Act of 2006," adopted in 2006, required that greenhouse gas emissions (primarily carbon dioxide from burning fossil fuels such as natural gas) be reduced to 1990 levels by 2020, with an 80 percent reduction from 1990 levels by 2050. In 2008, California passed legislation requiring utilities to procure 33 percent of their energy from renewable resources by 2020 and, in 2015, the state doubled down with new legislation requiring utilities to obtain 50 percent of their energy from

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[2] *See* Niranjan Ravindran's Declaration in Support of the Debtors' Chapter 11 Petitions and First Day Pleadings (the "Ravindran Decl.") [D.I. 10], ¶ 9; Expert Report of Phillip Muller, September 28, 2017, ("Muller Report").

renewable resources by 2030.[3] AB 32 also required that a "carbon tax" be imposed on businesses that burned fossil fuel as part of the "cap and trade program." This program, which became enforceable in 2013, implemented taxes on La Paloma that amount to over $25 million per year. The policy preference for renewable resources has materially reduced revenue and increased operating costs for merchant (non-utility) generators like La Paloma. Indeed, the California Independent System Operator (CAISO) determined, as reported in its *Annual Report on Market Issues & Performance* from 2011 through 2016, that energy prices were "substantially below" the fixed operating cost for an average new CCGT generator.[4]

The Facility also is adversely impacted by its remote location, which is too far from major cities to dependably provide electricity, subjecting it to transmission constraint or "congestion" pricing penalties that materially reduce the price received for electricity—in addition to the already reduced energy prices reported by CAISO.

As a result of these changes, no new gas-fired facilities have been built since 2010 unless they have the contracts necessary to operate profitably.[5] In short, there is no "market" for facilities like La Paloma, whether to build or buy.

The California State Board of Equalization (the "SBE") assesses the Facility to establish its value, which is then transmitted to Kern County, which actually levies and collects the tax.

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[3] Executive Order S-14-08; SBX1-2; SB 350.

[4] CAISO 2011 Annual Report on Market Issues & Performance ("Annual Report") at 45-46; 2012 Annual Report at 52; 2013 Annual Report at 55; 2014 Annual Report at 52; 2015 Annual Report at 53; 2016 Annual Report at 55.

[5] http://www.energy.ca.gov/sitingcases/all_projects.html; *see also* Muller Report at 10-11.

The SBE has largely ignored the regulatory impact on the market for gas fired generation in California. It levied massive assessments for the years in question as follows:

Year	Original SBE-Assessed Value	SBE–Assessed Value After Appeal
2012	$401,900,000	$377,600,000
2013	$333,300,000	$333,300,000
2014	$310,200,000	$310,200,000
2015	$290,800,000	$290,800,000
2016	$168,800,000	$136,100,000

These assessments cannot be reconciled with the standard of taxable value governing California property tax assessments. The "full cash value" for property tax purposes is "value in exchange," *i.e.*, "the amount of cash or its equivalent that property would bring if exposed for sale in the open market under conditions in which neither buyer nor seller could take advantage of the exigencies of the other, and both the buyer and the seller have knowledge of all of the uses and purposes to which the property is adapted and for which it is capable of being used." Rev. & Tax. Code, § 110(a). The SBE ignores the reality that no market exists for facilities such as La Paloma. While the property must be assessed even in the absence of an active market, nevertheless the value must reflect prevailing economic and regulatory conditions. The challenged assessments do not do so.

The SBE's expert Mark Pomykacz with Federal Appraisal substantially corroborates the SBE's administrative value determinations, reaching a cumulative value which is 95% of the SBE cumulative value below, although the Mr. Pomykacz does so using dramatically different assumptions:[6]

Year	Federal Appraisal	SBE-Assessed Value After Appeal
2012	$358,300,000	$377,600,000
2013	$352, 800,000	$333,300,000
2014	$329,000,000	$310,200,000
2015	$223,800,000	$290,800,000
2016	$139,200,000	$136,100,000

In contrast, La Paloma's opinions of value developed by evcValuation properly reflect the dismal market realities for gas fired generation in California:[7]

Year	evcValuation
2012	$36,000,000
2013	$30,000,000
2014	$12,000,000
2015	$2,700,000
2016	$1,700,000

Two appraisal issues largely explain the differences between the three groups of values: (i) whether the cost approach can be used at all for this property; and if so, how that appraisal method should be implemented; and (ii) whether revenues derived from long term contracts (actual or merely imputed) that exceed market rates on the dates of value can be included in the revenue stream capitalized pursuant to the income approach.

As to the cost approach, the SBE Staff utilized a cost approach that materially exceeded its own income approach by 200% to 300% for each year at issue. The

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[6] Expert Report of Mark Pomycacz, Federal Appraisal, Sep. 21, 2017 ("Federal Appraisal Report") at p. 60).

[7] Expert Report of Kevin Reilly, evcValuation, Sep. 28, 2017 ("evcValuation Report") Executive Summary at p. 2.

disparity between the two value indicators was caused by the SBE's failure to adequately reduce the cost indicator for economic obsolescence. Not every appraisal method is suitable for every property and the cost approach is not suitable for the Facility, in part, because the magnitude of the required depreciation and obsolescence adjustments renders the cost approach unreliable. Federal Appraisal conducts a cost approach, but places no weight on it because of the difficulty of calculating obsolescence, effectively conceding the SBE should not have relied on that indicator. (Federal Appraisal Report at p. 60). Nor does La Paloma utilize the cost approach to value the operating Facility. But, the subject assessments are all based 60% on the cost approach, and the SBE continued to use the cost approach in 2017 despite its litigating position in this action, such that the Court must address the invalidity of that method as part of the relief granted to La Paloma. Even though La Paloma and the SBE agree in this litigation that the cost approach should be accorded no weight for purposes of the valuing the operating Facility, the SBE's continued misuse of that appraisal method should be corrected by judgement.

As to the income approach, both the SBE and Federal Appraisal capitalize the actual above-market contract revenues received by La Paloma, contrary to California law. Ignoring reality, Federal Appraisal assumes such above-market or "out of market" revenue will continue indefinitely. (Federal Appraisal Report, § 21, p. 82-107). Such contracts are intangible assets and the revenue from those contracts cannot be used to assess the Facility. Use of above-market contracts for assessment purposes was expressly considered by the California Supreme Court in a case resolved against the SBE, *Elk Hills Power, LLC v. State Board of Equalization*, 57 Cal.4th 593 (2013). Including those revenue streams in the income approach is error.

In sum, the SBE has ignored market and regulatory realities to assess the Facility above fair market value in violation of fundamental appraisal standards required under California property tax law.

II. FACTUAL BACKGROUND

A. La Paloma's Business

La Paloma owned a natural gas-fired, combined cycle electric generating facility consisting of four identical power blocks with an aggregate nameplate generating capacity of 1,022 megawatts ("MW") located on an approximately 400-acre site in McKittrick, California that commenced operations in 2003. (Ravindran Decl., ¶ 9; Muller Report at 9-10). The Facility is located approximately 110 miles northwest of Los Angeles and 40 miles west of Bakersfield, which is at a point on the electric transmission grid where it can conceivably provide energy for use in both northern and southern California. (Ravindran Decl., ¶ 9). The Facility employs a technology that reduces the amount of fuel used and the amount of carbon dioxide emitted relative to many other natural gas-fired electric generating facilities. (*Id.*)

The Facility is operationally controlled by the California Independent System Operator Corporation ("CAISO"). (*Id.*, ¶10). CAISO is an independent electric grid operator that manages the grid and flow of power covering approximately 80% of California and a small part of Nevada. (*Id.*) The Facility is not owned by or affiliated with PG&E or any other utility that sells electric energy directly to customers. (*Id.*) Instead, the electric energy and certain related services from the Facility are sold into a centralized electric market operated by CAISO and purchased by utilities for distribution or sale to retail customers. (*Id.*)

The Facility operates as a merchant facility, which means that, with minor exceptions, it does not have a contract for sale of its output at a fixed price but rather is subject to prices in the CAISO day-ahead market that vary from hour-to-hour based on the amount of demand and the amount of supply being offered by competing sellers. (*Id.;* Muller Report at 9-10). During the period at issue, La Paloma relied on a series of fairly short-term market-priced agreements with various counterparties. (Muller Report at 10). La Paloma was never, and could never have been, the recipient of an above-market contract, typically referred to as a standard offer contract, authorized under the federal Public Utility Regulatory Policies Act ("PURPA") or any other government program. (*Id.*) La Paloma was developed in anticipation of recovering its costs through wholesale market mechanisms designed to eliminate the justification for above-market prices implemented by PURPA. (*Id.*) Thus, as of December 6, 2016 (the "Petition Date"), 97.6% of La Paloma's revenue was generated from the sale of energy into the CAISO market. (Ravindran Decl., ¶ 10).

La Paloma also sold a product called resource adequacy capacity ("RA"), which helps utilities to ensure that they have access to adequate electric generating capacity available to serve the needs of their customers and to maintain the reliability of the electric grid. (*Id.*, ¶ 11). As of the Petition Date, only 2.4% of La Paloma's revenue was generated from the sale of RA. (*Id.*)

B. Changes to the California Power Generation Market Negatively Impact the Facility

La Paloma's bankruptcy filings are the result of a confluence of adverse market developments, a challenged regulatory environment, mounting compliance obligations under California's "cap and trade" scheme, and substantial debt service requirements.

(Ravindran Decl., ¶ 30). Slower than expected growth in demand for electric energy, changes in commodity markets, and the build out of renewable generation resources in the California market have compressed the Facility's generation output and reduced the margin between the market price for electric energy and the market price for natural gas fuel consumed in generating such energy (this margin often is referred to as a "spark spread"). (*Id.*) To mitigate these pressures, La Paloma attempted to secure additional contracts for the sale of RA, but was unable to meet this goal. (*Id.*)

These issues have been exacerbated by an inhospitable regulatory environment. (*Id.*) CAISO has failed to provide a market mechanism to compensate the Facility and other similar facilities for the reliability service that they provide. (*Id.*) Indeed, CAISO has denied or withdrawn outage requests from the Facility to place some of its units in "outage" mode so that they would not be required to operate. (*Id.*) As a result of the foregoing factors, the margins La Paloma earned from energy sales had been compressed, and its cash flows were insufficient to address their environmental requirements, together with debt service payments of over $30 million per year for the years at issue. (*Id.*)

1. La Paloma's Revenue Declines

La Paloma experienced a substantial decline in its generation output and margins from merchant sales of output from the Facility, despite efforts to sell all of the energy and other services available from the Facility. (Ravindran Decl., ¶ 31). La Paloma generally offered for sale into the CAISO market energy from all four of the Facility's units. (*Id.*) When the price of such offer was at or below the clearing price in the wholesale market, then CAISO provided an award and subsequently "dispatches" the unit to generate and sell energy. (*Id.*) The Facility is regularly dispatched by CAISO for power when it is economic to operate, but capacity factors (*i.e.*, the amount of energy actually generated compared to the maximum capacity to generate) across the full year cycle and spark spreads have compressed. (*Id.*) La Paloma had sought to enter into bilateral contracts with third parties to sell energy and capacity (*i.e.*, RA) at fixed prices but was unable to find additional purchasers willing to enter into such contracts. (*Id.*) In addition, despite efforts to augment revenues with sales of RA, La Paloma had only been able to find purchasers for 17.6% of the Facility's capacity for 2016. (*Id.*)

The plight of natural gas-fired electric generators in California is discussed in CAISO's *Annual Report on Market Issues & Performance* from 2011 to 2016. Taking the 2015 report as an example, CAISO reported that a combined cycle, natural gas-fired electric generating facility (such as the Facility) requires compensation of $165.20 per year for each kilowatt of capacity to cover its fixed costs; however, the report stated that net revenues in 2015 to cover fixed costs of such units were only $39.62/kW-year in the northern California market zone and $45.77/kW-year in the southern California market zone.[8] The CAISO reports from 2011 to 2016 are consistent in this respect, reporting every year that "net revenue estimates for a hypothetical combined cycle unit in NP151 and SP 15 both fall substantially below the . . . annualized fixed costs."[9]

As a result, the California Energy Commission reports that gas fired facilities are not being built.[10] Indeed, La Paloma was one of the last natural gas-fueled power plants in California to be built without a long-term power purchase agreement with a utility.

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[8] CAISO 2011 Annual Report on Market Issues & Performance at 53-54.

[9] CAISO 2011 Annual Report on Market Issues & Performance ("Annual Report") at 45-46; 2012 Annual Report at 52; 2013 Annual Report at 55; 2014 Annual Report at 52; 2015 Annual Report at 53; 2016 Annual Report at 55.

[10] http://www.energy.ca.gov/sitingcases/all_projects.html

(Muller Report at 10-11). There is no gas fired facility under construction except a peaker plant in SDG&E territory that has a power sales contract.[11] Two gas powered facilities are licensed, and have been so licensed since 2011 and 2012 respectively, but construction is "on hold."[12] No gas fired merchant plant has been built without a power sale agreement since 2005.[13] The market does not support construction of gas-fired plants when the mandate is to shift generation to "renewable" generation.

2. Failed CAISO Market Reform Efforts

CAISO proposed changes to its tariff in 2012 to implement a Flexible and Local Reliability Resource Retention mechanism. (Ravindran Decl., ¶ 33). The CAISO tariff is a document that is filed with Federal Energy Regulatory Commission ("FERC") that, among other things, establishes the terms and conditions for participation of sellers and buyers in the CAISO market. (*Id.*) The purpose of the proposal was to offer temporary financial support to electric generating resources that are otherwise uneconomic to operate but that provide important benefits to the market (for example, by offering the ability to quickly adjust to market conditions) and that support reliability of local portions of the electric grid. (*Id.*) However, FERC rejected CAISO's proposed tariff revisions, finding that they did not create proper price signals and that they failed to address the underlying need to ensure the presence of financial incentives for electric generating resources to enter and remain in the market. (*Id.*) At the time, FERC urged CAISO and its stakeholders to focus on the development of a durable, market-based mechanism that would provide incentives to ensure that electric generating resources would be available

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[11] http://www.energy.ca.gov/sitingcases/all_projects.html

[12] *Id.*

[13] *Id.*

to meet the resource adequacy and reliability needs of the CAISO market. (*Id.*) Since that time, no such durable, market-based mechanism providing needed resources and incentives to remain in the market has developed. (*Id.*)

3. CAISO Denies and Withdraws La Paloma's Outage Requests

As a result of the inability of the CAISO market to provide sufficient compensation to La Paloma for the past several years, La Paloma requested CAISO approval in May 2016 to designate units 1, 3, and 4 of the Facility as being in "outage" mode from July 1, 2016 to November 30, 2016, to alleviate the financial losses they were experiencing. (Ravindran Decl., ¶ 34). These proposed outages would protect La Paloma from being required to operate those units of the Facility. La Paloma argued that the outages were necessary because no RA had been procured from the units and operation was expected to be uneconomic. (*Id.*) These requests were denied by CAISO because the CAISO tariff did not have a provision for declaring outages for economic reasons. (*Id.*) In addition, in June 2016, CAISO canceled a previously approved maintenance outage for unit 2 due to the need for the Facility to be available to generate during an impending heat wave. (*Id.*)

4. La Paloma Unsuccessfully Seeks Alternative Compensation

La Paloma sought other forms of compensation, including proposing to enter into a "Reliability Must Run" ("RMR") contract with CAISO or being designated a "CPM" (Capacity Procurement Mechanism) resource under the CAISO tariff. (Ravindran Decl., ¶ 35). RMR and CPM contracts provide compensation to electric generating units that are needed to maintain the reliability of the electric grid but are not receiving sufficient compensation from the market to support continued operation. *Id.* However, even though CAISO previously found unit 2 of the Facility was needed during the 2016 summer heat wave, as discussed above, CAISO declined to execute an RMR or CPM contract with La Paloma. (*Id.*) Therefore, La Paloma was denied this relief. (*Id.*)

On June 17, 2016, La Paloma filed a complaint against CAISO with FERC, requesting that FERC issue an order requiring CAISO to grant La Paloma an RMR designation effective as of July 1, 2016, for units 1, 3, and 4 of the Facility, or otherwise provide a mechanism for cost recovery to allow La Paloma to continue operating those units. (*Id.*, ¶ 36). On October 3, 2016, FERC denied the complaint, finding that CAISO reasonably denied La Paloma's economic outage requests. (*Id.*)

5. Renewable Energy Resources Compress Output and Prices

Power generation in California is now focused on "preferred resources," including renewable resources and demand response that produce fewer greenhouse gas emissions. (Muller Report at 3, 11). Growth in the supply of lower marginal cost solar-power-generated electricity associated with "behind the meter" installations in California (*i.e.*, solar collectors installed by residential and commercial electric customers on the customer side of their electric meters that are capable of selling energy back to the electric grid whenever generation from the collectors exceeds the customer's needs), has resulted in a decrease in overall demand for electric generation from natural gas-fired units and other conventional generating resources, and also suppressed market clearing prices. (Ravindran Decl., ¶ 38; Muller Report at 9). Competition from utility scale solar and wind-powered electric generation has also contributed to this effect. (Ravindran Decl., ¶ 38; Muller Report at 9). However, because generation from solar and wind-powered resources is intermittent, due to changes in the amount of sunlight during the daytime (and of course the absence of sunlight at night) and variations in wind speeds, generation capacity from conventional resources is still needed. (*Id.*) In fact, electric generation from flexible resources, such as the Facility, that can quickly respond to changes in demand, is particularly important due to the increase in generation from intermittent resources; however, the CAISO market does not adequately compensate natural gas-fired electric generating resources for providing that flexibility. (*Id.*)

6. Low Natural Gas and Electric Prices Reduce Margins

In addition, technological improvements in hydraulic fracturing (fracking) have contributed to significant increases in U.S. natural gas production and decreased natural gas prices. (*Id.*, ¶ 39). While this has reduced the cost of fuel for the Facility, it also has reduced the price of electric energy in the CAISO market, because it has reduced the short-run marginal cost of gas-fired generators that typically set CAISO market prices. (*Id.*) This has reduced La Paloma's income and cash flows. (*Id.*)

C. <u>The SBE and Kern County Erroneously Assess the Facility</u>

La Paloma's analysis of its property tax liability has revealed significant errors in the historical assessments of the Facility. Among other things, the SBE's tax assessment practices did not adequately account for the regulatory and market conditions in which the Facility operated, and, as a consequence, the SBE consistently assessed the Facility far in excess of its fair market value from 2012 to 2016.

As set forth in La Paloma's Verified Complaint, in assessing the value of the Facility, the SBE incorrectly implemented two appraisal methods: the income approach and the cost approach:

- *Income Approach Errors.* The SBE developed a separate income approach for the Facility for each year in controversy, each of which materially overstated projected revenue and, thus, materially overstated the income and value. One factor leading to the SBE's inflated revenue projections was that the SBE utilized revenue from a private power sale agreement instead of simply using market revenue to the Facility for assessment purposes. An identifiable revenue stream could always be attributed to the favorable power sales agreement pursuant to which the Facility operated for certain of the years at issue, in contrast to market revenues. The favorable power sales agreement was an intangible asset that was exempt from assessment, yet the SBE did not remove the value of that favorable contract from the assessed value, or refrain from including such value in the assessment in the first place.

- *Cost Approach Errors*. The SBE developed a separate cost approach indicator for the Facility for each year in controversy, and each grossly overstated market value. Among other errors, the SBE did not account for all forms of obsolescence, which is a mandatory step in the cost approach. The SBE's cost indicator is materially greater than the income indicator for each year in controversy, but the SBE never explains or demonstrates why its cost indicator is reasonable, *i.e.*, why replacing the Facility would be economically feasible. Using 2016 as an example, in order to justify a purchase price equal to the revised cost indicator, the Facility would have to earn $32 million annually (13.825% (SBE's unloaded discount rate) x $232,371,071 million (SBE's cost indicator)). The SBE forecasts that the Facility would earn only $12,770,055 in 2016 (which grossly overstates actual revenue), which is only a fraction of what would be required to support the cost indicator used. The SBE does not explain why a buyer would pay nearly double the income indicator for the Facility; if a buyer did so it could not recover the purchase price by operating the Facility even under the SBE's unrealistic assumptions, much less obtain a return on such investment.[14]

The SBE then took the outputs of these error-riddled processes and weighted the income indicator 40% and the cost indicator 60% to arrive at a single market value. These weightings were wholly arbitrary. Moreover, weighting invalid or incomplete value indicators is not an accepted appraisal practice. Together, the SBE's use of flawed

[14] During La Paloma's chapter 11 case, the Debtors ran an extensive sales process to try and sell the Facility and the only two preliminary indications of interest received (not even offers, just indications of interest) were for $25 million and $75 million, respectively. Moreover, both offers were predicated on the Facility being sold free and clear of all liens, claims, interests, and encumbrances in addition to the asserted pre-close CARB liability (of more than $60 million) on account of the Debtors' emissions up until the date the Facility changed control (*i.e.*, taking into account potential CARB liability, parties were attributing little to no value to the Facility itself). As such, when the market spoke, it indicated that the Facility is worth *far less* than the SBE is assessing.

methods inflated the assessed value of the Facility for each year in question, which in turn led to improper calculations of La Paloma's property tax liability. As a result, the liquidating trustee is owed more than $14 million in tax refunds and statutory interest.

III. ARGUMENT

A. The SBE's Use of the Cost Approach Should be Expressly Disapproved

The SBE used a cost approach at the administrative level to establish the assessed value of the Facility for each year at issue. Moreover, even though the SBE's trial expert has opined that the cost approach should not be used, the SBE continued to use the cost approach in the 2017 assessment. A dispute exists concerning use of the cost approach that affects past and future assessments that must be resolved.

The cost approach assumes that the cost of building a new, similar facility sheds light on market value because a potential buyer would presumably consider building a facility instead of buying the subject. However, building another facility like the subject from 2012 to 2016 was not possible for both economic and regulatory reasons. Hence, the cost approach cannot shed light on the fair market value of the Facility.

The SBE's use of the cost approach was error for a host of reasons. *First,* it is a truism that cost does not equal value. The SBE's cost indicator was never tested for economic reasonableness, and in fact the SBE's own income indicator demonstrates that building a substitute or rebuilding the Facility would not be economic. *Second,* the cost approach is best suited for recently constructed facilities because such construction represents the market's determination that the facility was at least "worth" the cost of construction (*i.e.*, the cost of construction would be recovered and an adequate return on that cost could also be obtained in the market). Conversely, the cost approach is not appropriate when substantial depreciation and obsolescence exists, and an adequate return "of and on" the cost of investment cannot be obtained. Here, the magnitude of depreciation and obsolescence affecting the Facility rendered the cost approach unreliable and inappropriate. *Third,* the SBE failed to account for all obsolescence affecting the Facility, rendering the SBE's cost approach incomplete. *Fourth,* no gas fired merchant plants are being built without long term contracts (which were not available to build a replacement for the Facility) and so building a new facility is not an alternative to buying an existing facility or the subject (there is no "build or buy" decision). *Fifth,* building a new facility is impossible because regulatory approval could not be obtained.

Two sets of information set forth below demonstrate that the cost indicator was uneconomic and that even the degree of obsolescence calculated by the SBE renders the cost approach unreliable for the Facility.

First, the SBE cost indicator exceeded the SBE income indicator by factors of between 200% and 300%, as shown in the chart below:

Tax Year	CEA Indicator	Cost Indicator
2012	195,131,583	$499,243,500
2013	172,689,738	$440,395,569
2014	151,851,612	$440,394,569
2015	143,629,865	$388,960,966
2016	73,347,596	$177,939,361

Second, the amount of depreciation and obsolescence calculated by the SBE (without any deduction for an income shortfall, as discussed below) and used to establish the cost indicator was substantial, as follows:

Year	RCN[15]	Depreciation and Obsolescence	Percentage (Rounded)
2012	$758,752,000	$281,759,336	37%
2013	$769,232,000	$351,088,267	46%
2014	$817,440,000	$440,590,647	54%
2015	$837,352,000	$474,278,469	57%
2016	$905,472,000	$751,888,004	83%

These discrepancies are addressed in detail below to explain why the income approach alone is the proper method for valuing the Facility given the degree of obsolescence affecting it.

1. The cost indicator was not demonstrated to be economic

The reasonableness of the cost indicator is not a given to be automatically accepted—it must be verified. Under the heading "Limitations of the Cost Approach," in its *Guidelines for Substantiating Additional Obsolescence*, the SBE instructs that "[a]n appraiser cannot assume that the cost approach, or any valuation approach, automatically provides the best indicator of value. All available information must be analyzed to determine the best indicator of value. The cost approach is most reliable when the property being appraised is relatively new and has experienced little deprecation."[16] Hence, before the cost indicator may be considered, it must first be tested for reasonableness (economic feasibility), especially where the subject is not new and there is more than a "little" depreciation.

[15] "Replacement Cost New."

[16] SBE, *Guidelines for Substantiating Additional Obsolescence for Personal Property and Fixtures*, LTA No. 2010/030 (June 11, 2010), p. 28.

The basic principle is explained by the SBE's *Assessor's Handbook,*[17] as follows: "If a property owner would not, *or economically should not*, construct a replacement for the existing property if it were destroyed, then a value indicator from the cost approach has little relationship to market value. This occurs when reconstruction would not be economically feasible."[18] The Handbook also advises that "a cost estimate should be reviewed for the realism of the depreciation estimate and whether it is supported by market data."[19]

A cost study must be reconcilable with the income approach. This is so because "cost" is not "value"—it must be shown to be economic and so represent "value." The income approach provides the required economic reference point in the absence of sales data. The SBE's own appraisal guidelines recognize that a cost study must "consider the earning ability of the property," and that it:

> **[m]ust be reconcilable with other value indicators and other related financial or economic information**. Staff has traditionally used other value indicators to test the reasonableness of the replacement cost less depreciation (ReplCLD) indicator. . . . For the income indicator, [it must be explained] why the property is worth more or less than the capitalized income. . . . **[I]f the CEA indicator is lower than the ReplCLD . . . indicator, this may be an indication that a further adjustment for obsolescence may be required.**[20]

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[17] The *Assessors' Handbooks* are a series of manuals developed by the SBE to interpret California property tax laws. Though they do not have the force of law, courts routinely rely on and give great weight to *Assessors' Handbooks. See Elk Hills Power, LLC v. State Board of Equalization,* 57 Cal.4th 593, 616, 620-621 (2013) (citing AH-502 regarding intangible asset assessment issues with approval); *SHC Half Moon Bay v. County of San Mateo*, 226 Cal. App. 4th 471, 484-485 (2014) ("Assessors' handbooks . . . serve as a primary reference and basic guide for assessors, and have been relied upon and accorded great weight in interpreting valuation questions.").

[18] AH § 501, *Basic Appraisal,* (2002), p. 75 (emphasis added).

[19] AH § 504, Assessment of Personal Property and Fixtures, (October 2002), p. 90.

[20] SBE, *Guidelines for Substantiating Additional Obsolescence for State-Assessed Telecommunications Properties* (April, 2009) pp. 2-3 (emphasis added).

Here, the SBE's income indicator is a fraction of the SBE's cost indicator, plainly showing that further adjustment is required.

The SBE's own conclusions at the administrative level demonstrate that the cost indicator is uneconomic. In 2012, the SBE concluded that a willing, well-informed and prudent buyer would pay $540 million for a facility capable of generating revenue worth only $195 million after being capitalized. In 2016, the SBE concluded that a willing, prudent buyer would pay $223 million for a facility that is capable of generating revenue worth only $73 million after being capitalized. While La Paloma disputes these sums, the SBE's cost approach cannot be supported with market economics.

Two issues arise: What is the actual amount of obsolescence that should have been accounted for and how much depreciation and obsolescence will render the cost approach invalid?

2. The actual additional amount of required obsolescence is measured by the income approach

Economic obsolescence is established by measuring "[t]he relationship between replacement cost new and the cash flows the hypothetical replacement is capable of generating . . . compare the replacement cost new to the income indicator of value for the same property; *the difference is economic obsolescence*."[21] This text is cited by the SBE's *Guidelines for Substantiating Additional Obsolescence for Personal Property* (LTA no. 2009/033) a dozen times. The *Appraisal of Real Estate,* 13th Edition, notes that "[t]techniques and procedures from [the income approach] are used to analyze

[21] American Society of Appraisers, *Valuing Machinery and Equipment: The Fundamentals of Appraising Machinery and Technical Assets* (3rd Ed., 2011) p.80 (emphasis added).

comparable sales data *and to measure obsolescence in the cost approach.*"[22] The SBE advises that where the cost and income indicators are inconsistent, then "*additional external obsolescence is present in this property and is appropriately reflected in the income indicator.*"[23]

There are different ways to use income data to measure economic obsolescence. One way is to simply use the difference between the income and cost indicators to measure economic obsolescence, as suggested by the *Wind Turbine Guidelines*. Doing so here shows an additional economic obsolescence adjustment of $159,023,475 ($232,371,071 - $73,347,596) is required for 2016.

Another approach to quantifying economic obsolescence is to determine the implied return required on the cost indicator, determine the difference between that required return and the actual forecasted income, and then capitalize that sum and deduct it from the cost indicator.[24] Here, the implied return on the SBE's 2016 cost indicator is $32,371,071 ($232,371,071 (SBE's cost indicator) x .13825 (SBE's unloaded discount rate). The SBE forecasts annual income of only $12,770,055, leaving a shortfall of $19,417,985. This capitalizes to $140,455,588 using the SBE's unloaded discount rate of 13.825%.[25] The SBE Staff's 2016 cost indicator would, if properly adjusted, result in

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[22] *Id.*, at p. 445.

[23] SBE, *Guidelines for the Assessment of Wind Energy Properties,* LTA no. 2017/020, June 27, 2017, p. 17 (emphasis added).

[24] See, *The Appraisal of Real Estate* (13th ed.), p. 444 ("External Obsolescence Estimated by Capitalization of Income Loss.")

[25] This same method is used by SBE expert Federal Appraisal in this action to estimate economic obsolescence in their appraisal of the Facility as discussed below. Federal Appraisal estimates economic obsolescence of $554 million (68% of RCN plus entrepreneurial profit) in 2012, $522 million (73%) in 2103, $466 million (70%) in 2014,

values of between $160 million and $140 million lower using its own data and analysis for 2016 to account for earning shortfall relative to "cost."

Correctly accounting for all obsolescence increases the amount of depreciation and obsolescence as follows, using an average to the two methods just reviewed:

Year	RCN	Depreciation and Obsolescence	Percentage (Rounded)
2012	$758,752,000	$634,876,165	84%
2013	$769,232,000	$687,928,550	89%
2014	$817,440,000	$620,858,098	76%
2015	$837,352,000	$655,328,814	78%
2016	$905,472,000	$846,195,921	94%

(*See* Exhibit 1 (Additional Economic Obsolescence Worksheets, 2012-2016). Thus, correctly calculated depreciation and obsolescence, using the SBE's own (incorrect) income assumptions, shows RCN should be between 76% and 94% depending on year. These adjustments, which are substantially corroborated by Federal Appraisal, show more than a "little" depreciation and obsolescence.

The SBE Staff contended at the administrative level that it was excused from using the income approach to measure economic obsolescence because each method of appraisal should be carried out independently from the others, and using an income approach to measure economic obsolescence is "circular' in the sense that doing so simply results in a value equal to the income indicator. But Staff reads the requirement for "independence" in isolation, without regard to all other appraisal practice requiring the cost approach to be tested for reasonableness, and contrary the SBE's own appraisal guidelines.

$558 million (80%) in 2015, and $674 million (90%) in 2016. *See* Federal Appraisal, § 13.7, p. 48.

3. The amount of adjustment required for depreciation and obsolescence renders the cost approach inappropriate

The SBE's own independent trial expert, Mark Pomykacz with Federal Appraisal, has opined that the cost approach is unsuitable to appraise the La Paloma facility for all years at issue (2012-2016). Mr. Pomykacz concluded: "The primary reason why the cost approach is found to be unreliable is that it is too difficult to properly adjust for functional or economic obsolescence." (Federal Appraisal Report at p. 60). He also concluded that depreciation and obsolescence was 91% of RCN in 2016 calculated as: $1,137,567,485 (all forms of depreciation and obsolescence) / $1,247,283,450 (RCN, including an unsupported 15% component for entrepreneurial profit). (Federal Appraisal Report at p. 47; *see also* footnote 24, *supra*).

The SBE's *Guidelines for the Assessment of Wind Energy Properties* offer some guidance about the relatively "little" degree of obsolescence required to render the cost approach unreliable.[26] In the example provided, RCN was $250 million, the cost indicator was $182.5 million after depreciation, and the income indicator was $155.5 million, for a difference of $27 million. Depreciation totaled $67.5 million, or 27% of RCN. The external obsolescence component ($27 million) was only 10.8% of RCN. Combined depreciation and obsolescence was only about 40% of RCN. Yet, the *Guidelines* advise "[b]ecause the property is believed to have a significant amount of additional external obsolescence, no reliance should be placed on the cost approach in accordance with Rule 6."[27] Here, depreciation and obsolescence (ranging from a low of

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[26] SBE, *Guidelines for the Assessment of Wind Energy Properties*, LTA no. 2017/020, June 27, 2017, p. 17.

[27] *Id.*

76% in 2014 to a high of 94% in 2016) grossly exceed the limit beyond which the cost approach cannot be used.

The Court should articulate a "bright line" level of depreciation and obsolescence for the Facility, which if exceeded, precludes use of the cost approach. The rule is that "The cost approach is most reliable when the property being appraised *is relatively new and has experienced little deprecation.*" Cal. Code Regs, title 18, § 6. La Paloma requests that the combined depreciation and obsolescence factor which renders the cost approach inappropriate be set at 50%: the Facility is not "new" and 50% is materially greater than that the 40% benchmark the SBE has articulated for excessive depreciation and obsolescence, and materially greater than a "little" depreciation under any accepted meaning of the word. This threshold is particularly reasonable in the context of the unique market and regulatory limitations affecting the Facility.

B. <u>The Revenue from the Out-of-Market Contracts Held by La Paloma Cannot be Used to Assess the Property.</u>

The SBE Staff's Capitalized Earnings Ability (*i.e.*, income approach or "<u>CEA</u>") indicator improperly includes out-of-market energy prices and other revenues based on favorable contracts not available to market participants generally, which represent tax exempt intangible assets. These above market income streams can be readily identified. At trial, Federal Appraisal also uses these contractual revenues. Doing so was error. The SBE has an "active duty" to exclude the value of intangible assets from assessment and has violated that duty.

1. The SBE has an independent, active duty to avoid assessing exempt intangible assets.

The SBE has an affirmative duty to remove the value of intangible assets from assessed values. The California Court of Appeal has stated this duty as follows:

> *[T]he Board's appraisers are required by law to identify and value intangible assets, if any, and exclude these values from the appraisal of the taxpayer's property.*
>
> * * * * *
>
> [W]here the types of intangible assets identified by Sprint may reasonably be said to exist, *the Board must exclude* their values when assessing the tangible property for taxation.
>
> * * * * *
>
> To permit the Board and its appraisers to ignore such widely accepted categories of intangibles with no explanation, other than it was appraising the "enhancement value" of the intangibles, would grant the Board unfettered discretion in its assessment practices, thereby precluding any meaningful judicial review.

GTE Sprint Communications Corp. v. County of Alameda, 26 Cal. App.4th 992, 999, 1004, 1007-1008 (emphasis added).

The California Supreme Court puts the burden of ensuring that exempt intangible assets are not assessed squarely on the SBE: "Section 110(d)(2) requires *taxing authorities* to value intangible assets and *actively remove* that value from a unit's taxable base value, so that the intangibles are not directly taxed." *Elk Hills Power,* 57 Cal.4th at 608 (emphases added.)

Here, the SBE ignored its statutory obligations by capitalizing net operating revenues attributable to the business, including above market contracts, and by failing to remove the value of such contracts or any other intangible asset from their appraisal.

2. The value of intangible assets must be removed from an assessment even if such assets are required to utilize the property at its highest and best use

Even if the intangible assets are necessary for the beneficial and productive use of a property, they remain exempt and their value must be excluded from assessment:

> If the plaintiff taxpayer presents evidence that the value of intangible assets contributed in some way to the unit valuation of its taxable property, the court must first determine if those intangible assets were necessary to the beneficial or productive use of the property, because if they are not, then they could not have been taken into account in the

> valuation. (§ 110, subds. (d), (e).) Second, *if the intangible assets are necessary to the beneficial or productive use of the taxable property, the court must determine* whether the plaintiff has put forth credible evidence that the fair market value of those assets has been improperly subsumed in the valuation. ***If so, then the valuation violates section 110(d)(1), which prohibits an assessor from using the value of intangible rights and assets to enhance the value of taxable property, and the fair market value of those assets must be removed pursuant to section 110(d)(2).***

Elk Hills Power, 57 Cal. App. 4th at 615 (emphases added).

Thus, even if a contractual revenue stream is necessary for the beneficial and productive use of a property, or "contributes in some way" to the value of a property, that asset remains exempt from assessment. The *value,* as separate and distinct from the *existence,* of such asset cannot be "reflected" in the assessed value or "enhance" (increase) the assessed value. *See* Rev. & Tax. Code § 110(d)(1) ("The value of a business using taxable property shall not enhance or be reflected in the value of the taxable property."). Instead, the incremental contribution of value from that exempt intangible asset must be identified and removed from the assessed value (or not included in the first place.)

The California Supreme Court distinguishes between simply *assuming the existence* of an intangible asset required to operate a property and *taxing* that asset:

> Section 110(d)(1) prevents *the value* of intangible assets from enhancing or being reflected in the valuation of taxable property. Section 110(e) allows assessors to enhance the valuation of taxable property, not by including *the value* of intangible assets in the valuation (see 110(d)(1)), but simply by *assuming the presence* of intangible assets when valuing the taxable property put to beneficial or productive use. While the value of the taxable property is enhanced, it is not enhanced by *the value* of intangible assets. That would violate section 110(d)(1) as well as section 212(c).

Elk Hills Power, 57 Cal. App. 4th at 613, 615 (emphasis added). Thus, even where an asset provides the means by which a property is put to use and may be "considered" in assessing that property, the actual value of that asset is exempt and must be removed from the assessed value.

3. The cases of *Watson Cogeneration* and *Freeport McMorran*, holding that revenue from above-market power sales agreements can be considered for property tax services, are distinguishable and have been superseded by the California Supreme Court's Decision in *Elk Hills Power Company*

Two California cases have held that the revenue from an above market power sale agreement was properly considered to assess the power plants holding those contracts. *See Freeport McMoran Resources v. County of Lake,* 12 Cal. App.4th 634 (1993); *Watson Cogeneration Company v. County of Los Angeles,* 98 Cal. App.4th 1066 (2002). Both cases are distinguishable and both cases are superseded, and their approaches rejected, by the California Supreme Court's decision in *Elk Hills Power*.

As an introduction, both cases address how "standard offer" power sale contracts created for "Qualifying Facilities" ("QFs") would be handled for property tax assessment purposes. QFs were a new class of generating facility created in 1978 under PURPA and defined as "[a] small power producer or co-generator that meets certain guidelines and thereby qualifies to supply generating capacity and electric energy to utilities, which must purchase this power at a price approved by the state regulatory bodies."[28] Under this regulatory scheme, a QF was required to use renewable or alternative energy sources, and meet certain efficiency and fuel-use standards (which the Facility never met). PURPA sought to stimulate development of this new class of power producers by creating a market, including the development of four "Standard Offer" contracts that Investor-Owned Utilities ("IOUs") were required to make available to third party QFs. Following

[28] Pacific Gas and Electric Company, *Resource, An encyclopedia of energy utility terms* (2nd ed., 1992), p. 366.

California's energy market restructuring in the 1990s, the Standard Offer contracts offered to QFs became historical artifacts that are no longer available.

i. Freeport McMoran Resources v. County of Lake

Freeport considers whether the revenue streams earned under a Standard Offer 4 ("SO4") contract issued in 1983, which provided for fixed energy prices in excess of market prices, could be included in the revenues being capitalized to determine the assessed value of a power plant in 1989. *Freeport-McMoran,* 12 Cal. App. 4th at 637-638. No new SO4 contracts were available on the January 1, 1989 date of value, but the existing SO4 contract remained in force. *Id.* at 639. The taxpayer argued that the SO4 contract revenues could not be considered because they violated the principle that objective market based revenues must be used determine the revenue to be capitalized and because the SO4 was an exempt intangible asset. *Id.* at 642.

The Court of Appeals rejected both of the taxpayer's arguments, holding that the above-market power sales agreement could be considered for property tax purposes for two reasons. First, the SO4 revenue stream is what a prospective purchaser of the property would anticipate earning and thus represented the "market." *Id.* at 644. The Court of Appeal observed that "60 to 70 percent of the 1,300 to 1,500 qualifying facilities in California operate with SO4 contracts" and so the evidence showed that "the proper market" was that measured by SO4 contracts. *Id.* at 644-645. Second, the Court of Appeal found "intangible values that cannot be separately taxed as property may be reflected in the valuation of taxable property." *Id.* at 645 (internal punctuation omitted.) It explained: "In this case, the SO4 contracts are the means by which appellants properties are put to beneficial use and must be considered in assessing the properties. . .

[B]ecause the SO4 contract is the means by which appellant can sell the electricity it produces, the income generated by the SO4 contract is inextricably tied to the beneficial use of the property and properly considered in assessing its value." *Id.* 645.

ii. Watson Cogeneration Company v. County of Los Angeles

Watson also considered the assessment of a power plant operated pursuant to Standard Offer-type contract (a modified SO2 version made in 1984) and addressed the same issue concerning the assessment of an intangible asset as was considered in Freeport. *Watson* considered a different energy market than did *Freeport*, because by date of value considered (January 1, 1997) the electricity markets had been deregulated, which allowed the taxpayer to sell electricity without a Standard Offer contract. *Id.* at 1073. The taxpayer contended that *Freeport* was based on the fact that the SO4 contract there was the only means by which the taxpayer could have sold electricity into the market, and so that contract was "inextricably tied to the beneficial use of the property." *Id.* Thus, even if Freeport had been correctly decided, it was no longer applicable in light of changes in the market which had changed to eliminate the necessity of having a standard offer contract to operate as a qualifying facility. *Id.*

Watson followed *Freeport,* observing that the California Power Exchange pursuant to which the taxpayer could have sold electricity had not yet begun operation on the valuation date, thereby sidestepping a key issue. *Id.* at 1074. Moreover, the taxpayer conceded that while it could have operated without the SO2, its operations would be more profitable utilizing the contract. *Id.* Thus, *Watson* concluded that the "highest and best of the property was as a qualifying facility with a power purchase agreement." *Id.*

Watson, however, added a line of analysis not present in *Freeport. Watson* emphasized that the SO2 was the product of "government incentives specifically intended to encourage their development. . . .The very existence of the project was based on these agreements. . . . So long as the project continues to operate as a qualified facility, receiving the predictable income stream agreed-upon in the power purchase agreement, it is appropriate to value the property based on its actual income." *Id.* at 1075.

iii. Freeport and Watson have been superseded by statute and case law, and never would have applied to the Facility

Freeport relied heavily on the idea that the revenues generated by the SO4 could be "reflected" in the assessed value. *Freeport*, which was decided in 1993, predated amendment of Revenue and Taxation Code sections 212(c) and 110(d)(1) in 1996, both of which expressly prohibit its reasoning (*i.e*, that "intangible values that cannot be separately taxed as property may be reflected in the valuation of taxable property"). *Freeport*, 12 Cal. App. 4th at 645. In direct contrast, both statutes provide that "the value of intangible assets and rights shall not enhance or be reflected in the value of the taxable property." *Watson*, which was decided in 2002, also violated this prohibition, but did so by simply ignoring the statutes—which it failed to mention.

Watson's conclusion that the "highest and best" use of the property is defined by the income stream derived from an intangible asset, thereby rendering that otherwise exempt asset subject to assessment, was expressly considered and rejected by the California Supreme Court in *Elk Hills Power.* The Supreme Court repudiated *Watson*:

> The "beneficial or productive use" of the property as used in sections 110(e) and 212(c) has been equated with the 'highest and best use' of the property. (*Watson Cogeneration Co. v. County of Los Angeles* (2002) 98 Cal.App.4th 1066, 1070-1071, 120 Cal.Rptr.2d 421.) Whether one assessed property at its "highest and best" use or at its 'beneficial and productive use," its valuation is still subject to the deductions for the value

> of intangibles from the unitary value of the property under sections 110(d) and 212(c)."

Elk Hills Power, 57 Cal. 4th at 617 n.11. Thus, even where the intangible asset is required for the beneficial and productive use of the property, the value of the intangible assets subsumed in the assessed value must be removed.

Aside from the legal disabilities of *Freeport* and *Watson*, both cases are factually distinguishable. *Watson* distinguished the cases excluding the intangible component of typical business contracts from assessment because the "power generation facilities in *Freeport-McMoRan* and this case are different from the businesses assessed in the cited cases; and the power purchase agreements are different from the intangibles in those cases." *Watson,* 98 Cal. App. 4th at 1075. *Freeport* and *Watson* considered specialized above-market contracts that (i) typified the market for a class of power generation facilities having special operating characteristics, (ii) were established by government action to incentivize small power production, and (iii) could not be made or modified without government approval. None of those characteristics exist for La Paloma's contracts.

La Paloma also does not enjoy the special factors *Watson* and *Freeport* considered to be determinative. La Paloma could never have qualified to participate in the QF "market" even had it been in operation when such contracts existed because it was not the type of generator for which the FERC created the "standard offer market."

La Paloma's expert report of Phillip Muller, a well-recognized expert in the California Energy Markets, explains that La Paloma was built a merchant facility, and was intended to sell power to the California Power Exchange. As such, it was dependent on negotiated contracts with utilities, or participation in CAISO's day-ahead and real time energy markets. The contracts La Paloma held were not regulated by the State and could be made and/or modified without government approval, unlike the SO contracts. Because La Paloma was not built as a cogeneration facility and has a generating capacity greater than 80MW, it could never have qualified as a QF, obtained a Standard Offer contract, or participated in the special "QF" market. In any event, the Standard Offer contracts were suspended in 1986, 17 years before La Paloma commenced operation.

The above-market contracts held by La Paloma could not have been obtained in the market on any of the valuation dates at issue and no potential buyer of an existing merchant gas fired power plant could have expected to obtain any kind of favorably priced power sales agreement. (Muller Report at p. 11). The California Public Utilities Commission has specifically ruled that long-term contracts for natural gas generators are only available to support construction of new resources if required to meet incremental need, which would exclude any buyer of La Paloma from obtaining such contracts. (*Id.*) Indeed, when La Paloma sought RMR or CPM contracts from CAISO to compensate its availability to maintain the reliability of the electric grid, CAISO rejected La Paloma's proposal and, in 2016, FERC affirmed CAISO's decision by denying La Paloma's request for an order requiring issuance of an RMR designation. *See* § II.B.5, *supra.*

4. A contractual right to receive revenue is a tax exempt intangible asset

The revenue received from above-market contracts cannot be considered for purposes of assessing the Facility. This is so because the revenue from such contracts is above that prevailing in the market, and derives from contracts which are not available to the market generally. Such contracts are intangible assets.

The SBE's assessment authority is limited to tangible assets, such as land, buildings, fixtures (*i.e.*, machinery and equipment) and personal property (*e.g.*, desktop computers). The value of a business or "business enterprise" is not assessable, nor are the intangible assets which contribute to, or are necessary for operating, the business. *See* Rev. & Tax. Code, §§ 110(d)(1)(2); 212(c) ("Intangible assets and rights are exempt from taxation and . . . the value of intangible rights shall not enhance or be reflected in the value of the intangible property."). Section 110 provides, in part:

> (d) Except as provided in subdivision (e), for purposes of determining the "full cash value" or "fair market value" of any taxable property, all of the following shall apply:
>
> (1) The value of intangible assets and rights relating to the going concern value of a business using taxable property shall not enhance or be reflected in the value of the taxable property.
>
> (2) If the principle of unit valuation is used to value properties that are operated as a unit and the unit includes intangible assets and rights, then the fair market value of the taxable property contained within the unit shall be determined by removing from the value of the unit the fair market value of the intangible assets and rights contained within the unit.

Here, the principle of "unit valuation" is adopted by both parties because the value of the entire enterprise operating the Facility is determined by capitalizing net operating revenue. If those revenues include sums resulting in part from intangible assets, then an additional step is required to remove the value of such assets from the capitalized income stream.[29]

[29] La Paloma avoids including the value of the over-market contracts in its value conclusion by using market pricing. Then, La Paloma makes a discrete adjustment to remove the value of operating intangible assets based on publically available market information. The SBE, in contrast, capitalizes the contract revenues and makes no deduction for any intangible assets subsumed in the income indicator.

Contract rights, including marketing contracts, are intangible assets exempt from taxation. In *GTE Sprint Communications Corp. v. County of Alameda,* 26 Cal. App. 4th 992 (1994), the SBE used an income approach to establish the assessed value of the assets at issue. That income approach necessarily included the value of all the assets, tangible and intangible, that collectively generated the revenue that the SBE capitalized. The taxpayer separately established the value of specific intangible assets and deducted the value of those assets from the income indicator to segregate the assessable and non-assessable assets, but this evidence was ignored by the SBE (just as the SBE ignored the evidence submitted La Paloma). The SBE contended that the income approach method inherently accounted for (removed) the value of intangible assets by removing expenses associated with those assets.

The First District Court of Appeal has rejected the SBE's position, holding: "In our view the Board and its appraisers erred in assuming that unit valuation, especially when calculated by the CEA [income] method, necessarily taxes only the intangible values as they enhance the tangible property." *GTE Sprint,* 26 Cal. App 4th at 1004. The Board's duty to exclude intangible assets extended to favorable broadband leases of transmission capacity from other carriers, favorable property leases, advertising agency relationships, favorable debt financing contracts, and an inventory of advertising materials, among other things. *Id.* at 998. The Court of Appeal stated: "where the types of intangible assets identified by [GTE] may reasonably be said to exist, the Board must exclude their values when assessing the tangible property for taxation. *Id.* at 1007.

Other California property tax cases have similarly confirmed that contractual rights are intangible assets. *County of Orange v. Orange County Assessment Appeals*

Bd., 13 Cal. App. 4th 524, 533 (1993) (nontaxable intangible assets were included in marketing and programming contracts); *Shubat v. Sutter County Assessment Appeals Bd.*, 13 Cal. App. 4th 794 (1993) (cable television franchise agreement and a non-competition agreement); *County of Los Angeles v. Los Angeles Assessment Appeals Bd.*, 13 Cal. App. 4th 102 (1993) (airport car rental concession contract); *Service America Corp. v. County of San Diego,* 15 Cal. App. 4th 1232, 1238 -1239 (1993) (ballpark food concession contract); *County of Stanislaus v. Assessment Appeals Bd.*, 213 Cal. App. 3d 1445, 1454-1455 (1989) (cable television franchise agreement).

The SBE has also expressly recognized that non-taxable intangible assets and rights may be created by private contract. In Assessor's Handbook Section 502, *Advanced Appraisal,* the SBE advises in pertinent part:

> **Private Contract Rights**
>
> An intangible right may also be created by private contract. An example of such an intangible right is the contractual right to operate a particular chain restaurant pursuant to the terms of a commercial franchise. . . . [T]he right to operate a valuable commercial franchise relates primarily to the business entity's enterprise-related activities. Thus, a franchisee's rights under a valuable commercial franchise are examples of intangible rights whose primary purpose is not to authorize a more productive use of taxable property, but ***rather to authorize the use of a trade name or other legally protected intellectual property, or the right to conduct a specified business operation, in the conduct of a business entity's enterprise-related activities.***

AH § 502, *Advanced Appraisal,*(2002) at p. 155 (emphasis added).

Favorable contracts are widely recognized by appraisers as intangible assets. *See* Reilly & Schweihs, *Valuing Intangible Assets* (1998), Chapter 16, pp. 311 ff. ("[A] contract intangible can result from any number of the numerous and diverse binding agreements consummated daily."): Smith & Parr, *Intellectual Property: Valuation,* *Exploitation and Infringement Damages* (2005) p. 65.) ("Contracts for naming rights should be viewed in the context of favorable contracts.")

An additional background point is that California property tax practice requires (in addition to exempting intangible assets from assessment) that existing contracts such as leases be disregarded in favor of market pricing prevailing on the valuation date. Thus, if a fully leased apartment building or office is subject to an above or below market lease at the time of sale, the sales price of the property based on the out of market leases will be disregarded and the value determined based on prevailing vacancy and lease rates.[30]

C. <u>The SBE's Trial Appraisal Violates Fundament Assessment Standards</u>

The new SBE income approach is flawed in many respects, but four of the errors are particularly notable: *First,* the new SBE income approach projects non-existent income based on contracts that are not assessable as discussed above, and which double-counts generation. *Second*, the income approach is done on an "after tax" basis, deducting financing costs, depreciation and income tax in violation of SBE Rule 8(c). *Third*, the discount rate, if corrected for a single error, is actually greater than that used by La Paloma or SBE Staff and requires a material reduction in the value conclusion.

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[30] "In the vast majority of cases, the property tax appraiser must appraise the unencumbered fee simple interest. To be used as a comparable property, the sale price must either reflect the full fee simple interest or be adjusted to reflect the full fee simple interest. This adjustment is frequently required with income producing properties, which are often sold subject to leases. If a property is encumbered with a long term lease that is either above or below the current market rent, an adjustment for property rights conveyed is required. The appraiser must determine whether the contract rent for the property is different from the current market rent and adjust the selling price if necessary." AH 501, *Basic Appraisal* (January 2002), p. 90.

Fourth, Federal Appraisal overstates income by failing to account for the congestion pricing penalty imposed on the Facility due to its remote location.

These errors were required in order to force the SBE's current stand-alone income approach to match the hybrid assessed values proffered at the administrative level. As background, the SBE previously used a cost indicator that was a multiple of the income indicator, with the cost indicator weighted 60%, to establish the assessed values. The SBE's trial expert, on the other hand, rejects use of the cost approach altogether, and relies solely on the income approach. Federal Appraisal's income approach and the SBE's income approach at the administrative level therefor differ dramatically:

Tax Year	SBE Original Income Indicator	SBE–Assessed Value After Appeal	FA New Income Indicator
2012	195,131,056	$377,600,000	$358,300,000
2013	172,689,738	$333,300,000	$352, 800,000
2014	151,851,612	$310,200,000	$329,000,000
2015	143,629,865	$290,800,000	$223,800,000
2016	73,347,596	$136,100,000	$139,200,000

The SBE has dramatically changed its income approach at trial to match the values established by the SBE's administrative blended cost and income approaches. The assumptions and methods required to more than double the income indicator are methodologically and factually unsound. Federal Appraisal was plainly "working to a number" (*i.e.*, adopting assumptions as required to back into existing assessed values).

i. *Phantom Generation and Revenues*

Federal Appraisal assumes levels of revenue that are not achievable in the market. Federal Appraisal includes revenue for both "market based" energy sales and a 2007 contract known as a "tolling agreement." Including both forms of revenue overstates the level of generation to a level that is physically impossible. For example, the 2012 appraisal assumes the Facility runs at a 65% capacity factor which generates 5,819,268 MWh of electricity at a price of $40/MWh in year 1. This equates to $232,770,720 in electricity revenue (5,819,268 * $40 = $232,770,720). The same appraisal also includes revenue from a tolling agreement that equates to an additional $92,017,461 in revenue broken down in year 1 of the January 1, 2012 appraisal as follows:

Capacity Revenue:	$71,280,000 (Contracted capacity)
Variable O&M Reimbursements:	$18,474,175 (O&M reimbursements per contract)
Other Reimbursements:	$2,263,286 (start-up charges per contract)
Total	$92,017,461

Based on the net capacity assumption, the maximum potential electricity generation is 8,952,720 MWh. Federal Appraisal's analysis assumes market based electrical generation of 5,819,268 MWh. Per page 33 of La Paloma's 2012 Schedule H filing to with the SBE, electrical generation in year 1 associated with the tolling agreement is 5,842,560 MWh. This equates to a total generation in year 1 from market energy and tolling agreement of 11,661,828 MWh which exceeds Federal Appraisal's maximum electricity generation by 2,709,108 MWh or 130%.

In addition, Federal Appraisal used the actual pricing received by La Paloma for the contracted capacity as part of the tolling agreement. This revenue was above market rates. For example, as of January 1, 2012, the tolling agreement provided capacity revenue for 3 units or 720 MW (720,000 kW) at a price $8.25 per kW-month. Using the contract price of $8.25 per kW-month results in the contract capacity revenue of $71,280,000 (720,000 kW * $8.25 per kW-month * 12 months = $71,280,000). The market capacity price, based on a historical 3-year average from 2009 through 2011, was

$0.89 per kW-month. Using the same calculation with market based prices the capacity revenue would be $7,689,600 (720,000 kW * $0.89 per kW-month * 12 months = $7,689,600). Thus, *revenue is overstated by more than $60 million.* These contract revenues are then extended, at the rate of more than $20 million a year *after the tolling agreement expired,* into perpetuity. (Federal Appraisal, § 21, p. 82-107).

The result of Federal Appraisal's use of unachievable revenue levels is to materially overstate revenue for every tax year, which is then compounded when capitalized, resulting in income indicators that closely match the SBE's assessments.

ii. The income approach is after tax but California regulations prohibit use of after-tax cash flows for property tax purposes

Federal Appraisal prepared both "after tax" and "before tax" cashflows. The former exceed the latter by as much as $63 million (2014). The after tax version is $42 million and $52 million greater than the before tax version in 2012 and 2013, respectively. (Federal Appraisal Report at p. 55). Mr. Pomykacz adopts the after tax version to support his opinion of value. (Federal Appraisal Report at p. 60).

The after tax version of the cash flow is unrealistic both large and small. It is inconsistent with the overall regulatory market that is subsidizing green competition for gas-fired facilities, and it assumes cashflows with debt of 50% of the indicated value ($365 million in 2012, and so $182 million in debt) at 12%, with payments of $17,318,000 (principal and interest) annually for 15 years. (Federal Appraisal Report at p. 97-98 (2012)). These assumptions still leave net operating income.

Besides being inconsistent with actual operating reality, the after tax calculation includes deductions for interest, depreciation, and income tax. SBE Rule 8(c) expressly requires that cash flows done for property tax purposes be calculated on a *pre-tax basis*:

"Gross outgo does not include amortization, depreciation, or depletion charges, debt retirement, interest on funds invested in the property, or rents and royalties payable by the assessee for use of the property. Property taxes, corporation net income taxes, and corporation franchise taxes measured by net income are also excluded from gross outgo." Cal. Code Regs, tit. 18, § 8. Federal Appraisal violates mandatory assessment standards.

iii. The Federal Appraisal discount rate conclusion includes an unsupportable component, which if corrected, materially increases the discount rate and reduces the value conclusion

Federal Appraisal inexplicably deviates from the SBE discount rate applied to all other merchant power generators in California for property tax purposes. (La Paloma adopts the SBE discount rate, with two specific exceptions.) Federal Appraisal applies a negative "industry risk premium" in its rate "build up" to materially reduce the discount rate. The negative adjustment is massive: -2.96%, -3.64%, -4.67%, -4.67% and -5.80%, respectively for each year. (Federal Appraisal Report at p. 234, line 5). This adjustment implies that the Facility is *less risky than a nationwide power generation base that includes regulated utilities with guaranteed returns and nuclear power plants.* It is irrational to compare the risk associated with a California gas-fired power plant with a national portfolio of facilities governed by different regulatory and market risk.

If this risk reduction factor is removed, and the discount rate calculation is otherwise implemented without change, then the discount rate increases by 3.39% to 6.05% depending on the year, as shown in the following table:

Year	evc Discount Rate	FA Discount Rate	FA Corrected Discount Rate	FA Income Indicator	FA Corrected Income Indicator	Difference in Value
2012	17.73%	14.48%	17.87%	$318,000,000	$266,000,000	$52,000,000
2013	18.04%	14.85%	19.38%	$308,000,000	$246,000,000	$62,000,000

2014	15.04%	14.44%	19.39%	$272,000,000	$207,000,000	$65,000,000
2015	14.34%	15.54%	20.33%	$200,000,000	$162,000,000	$38,000,000
2016	15.20%	16.18%	22.23%	$119,000,000	$82,000,000	$37,000,000

Thus, the negative "Industry Risk Premium" is a $50 million issue.

iv. Federal Appraisal overstates pricing by failing to account for congestion price discounts.

Federal Appraisal does not account for the fact that La Paloma's gross margins suffer from transmission constraints resulting in lower electricity prices as compared to generators located in unconstrained regions in the CAISO market region. From 2013 through 2015, the Facility realized an average "haircut" on realized peak and off-peak electricity prices, as compared to the SP15 zonal price, of $2.56/MWh and $1.15/MWh, respectively. Using the Facility's historical net generation level as an example, this translates into annual lost revenues of up to $16 million if only running during peak hours. This "haircut" on realized electricity prices further reduces gross margins and the ability to run more frequently and recover fixed operating costs and remain profitable.

IV. CONCLUSION

For all the foregoing reasons, the Liquidating Trustee of the La Paloma Liquidating Trust respectfully requests that a judgment should be entered in its favor on its refund claim, including a refund of property taxes for all tax years at issue (2012 to 2016) based on the property values established by the evcValuation report submitted by La Paloma, statutory prejudgment interest on such sum, costs of suit herein, and other relief as the Court deems just and proper, including an order declaring that the cost approach is an unreliable and inappropriate method for valuing the Facility because it fails to account for material depreciation and obsolescence.

Dated: January 26, 2018
Wilmington, Delaware

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Exhibit 1

2012 - Additional Economic Obsolescence Worksheet

1. Income/Return Shortfall: $67,952,033

   ($499,243,500 [cost indicator following appeal] x .13611 [Unloaded Discount Rate]

   - Income Shortfall: $54,732,790

     ($67,952,033 [Required Return] - $13,219,243 [First Year NOI])

   - Unloaded Discount Rate: 13.611%

     (14.73% [Total CAP Rate] – 1.119% [Property Tax Rate])

   - Capitalized Shortfall: $402,121,740

     ($54,732,790 ÷ .13611)

2. Difference between Income and Cost Indicators: $304,111,917

3. Average Shortfall: $353,116,829

   (($304,111,917 + $402,121,740) ÷ 2 = $353,116,829)

4. Original Depreciation and Obsolescence: $281,759,336

5. Corrected Depreciation and Obsolescence: **$634,876,165**

   ($281,759,336 + $353,116,829)

6. Corrected percentage of depreciation and obsolescence: **84%**

   ($634,876,165 [Corrected Dep. and Obs.] ÷ $758,752,000 [RCN])

2013 - Additional Economic Obsolescence Worksheet

1. Implied Return: $61,250,076

   ($440,394,569 [Cost Indicator] x .13908 [Unloaded Discount Rate]

   - Income Shortfall: $51,373,964

     ($61,250,076 [Required Return] - $9,876,112 [First Year NOI])

   - Unloaded Discount Rate: 13.908%

     (15.04% [Total CAP Rate] – 1.132% [Property Tax Rate])

   - Capitalized Shortfall: $369,384,268

     ($57,373,964 ÷ .13908)

2. Difference between Income and Cost Indicators: $267,704,831

3. Average Shortfall: $318,544,550

   (($267,704,831 + $369,384,268) ÷ 2)

4. Original Depreciation and Obsolescence: $351,088,267

5. Corrected Depreciation and Obsolescence: **$687,928,818**

   ($318,544,550 + $369,384,268)

6. Corrected percentage of depreciation and obsolescence: **89%**

   ($687,928,818 [Corrected Dep. and Obs.] ÷ $769,232,080 [RCN])

2014 - Additional Economic Obsolescence Worksheet

1. Required Return: $55,478,917

   ($399,100,189 [Cost Indicator] x .13901 [Unloaded Discount Rate]

   - Income Shortfall: $15,761,833

     ($55,478,917 [Implied Return] - $39,717,084 [First Year NOI])

   - Unloaded Discount Rate: 13.901%

     (15.04% [Total CAP Rate] – 1.139% [Property Tax Rate])

   - Capitalized Shortfall: $113,386,325

     ($15,761,833 ÷ .13901)

2. Difference between Income and Cost Indicators: $247,248,577

3. Average Shortfall: $180,317,451

   (($247,248,577 + $113,386,325) ÷ 2)

4. Original Depreciation and Obsolescence: $440,590,647

5. Corrected Depreciation and Obsolescence: **$620,858,098**

   ($440,590,647 + $180,317,451)

6. Corrected percentage of depreciation and obsolescence: **76%**

   ($620,858,451 [Corrected Dep. and Obs.] ÷$817,440,000 [RCN])

2015 - Additional Economic Obsolescence Worksheet

1. Required Return: $51,331,179

   ($388,960,966 [Cost Indicator] x .13197 [Unloaded Discount Rate]

   - Income Shortfall: $23,893,214

     ($51,331,179 [Required Return] - $27,437,975 [First Year NOI])

   - Unloaded Discount Rate: 13.197%

     (14.34% [Total CAP Rate] – 1.143% [Property Tax Rate])

   - Capitalized Shortfall: $181,050,345

     ($23,893,214 ÷ .13197)

2. Difference between Income and Cost Indicators: $245,331,101

3. Average Shortfall: $231,190,778

   ($245,331,101 + $181,050,345)

4. Original Depreciation and Obsolescence: $474,278,469

5. Corrected Depreciation and Obsolescence: **$655,328,814**

   ($474,278,469 + $181,050,345)

6. Corrected percentage of depreciation and obsolescence: **78%**

   ($655,328,814 [Corrected Dep. and Obs.] ÷$837,352,000 [RCN])

2016 - Additional Economic Obsolescence Worksheet

1. Income / Return Shortfall

   - Implied Return: $24,600,117

     ($177,939,361 [Cost Indicator] x .13825 [Unloaded Discount Rate])

   - Income Shortfall: $11,830,062

     ($24,600,117 [Required Return] - $12,770,055 [First Year NOI])

   - Unloaded Discount Rate: 13.825%

     (15.2% [Total CAP Rate] – 1.375% [Property Tax Rate])

   - Capitalized Shortfall: $85,570,069

     ($11,830,062 ÷ .13825)

2. Difference between Income and Cost Indicators: $104,591,765

3. Average Shortfall: $95,080,917

   (($104,591,765 + $85,570,069) ÷ 2)

4. Original Depreciation and Obsolescence: $751,888,004

5. Corrected Depreciation and Obsolescence: **$846,968,921**

   ($751,888,004 + $95,080,917)

6. Corrected percentage of depreciation and obsolescence: **94%**

   ($846,968,921 [Corrected Dep. and Obs.] ÷ $905,472,000 [RCN])

PRIVILEGED

Privileged and Confidential Informational Omitted Pursuant to 18 C.F.R § 388.112

Attachment 18 – Purchase and Sale Agreement

Initial Brief of the

California Independent System Operator Corporation

PG&E – La Paloma Unexecuted LGIA

ER21-2592

February 13, 2023

ATTACHMENT CONSISTS OF PRIVILEGED MATERIAL OMITTED

PURSUANT TO 18 C.F.R. § 388.112

CERTIFICATE OF SERVICE

I certify that I have served the foregoing document upon the parties listed on the official service list in the captioned proceedings, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2010).

Dated at Folsom, California this 13th day of February, 2023.

/s/ Jacqueline Meredith
Jacqueline Meredith
An employee of the California ISO