

PUBLIC UTILITIES COMMISSION

505 VAN NESS AVENUE

SAN FRANCISCO, CA 94102-3298



April 7, 2016

Advice Letter 4780-E

Erik Jacobson
Director, Regulatory Relations
Pacific Gas and Electric Company
77 Beale Street, Mail Code B10C
P.O. Box 770000
San Francisco, CA 94177

**Subject: Advice Letter Filing of PG&E's Sixth Renewable Auction
Mechanism Power Purchase Agreements**

Dear Mr. Jacobson:

Advice Letter 4780-E is effective as of February 21, 2016.

Sincerely,

A handwritten signature in cursive script that reads "Edward Randolph".

Edward Randolph
Director, Energy Division

January 22, 2016

Advice 4780-E

(Pacific Gas and Electric Company ID U39 E)

Public Utilities Commission of the State of California

Subject: Advice Letter Filing of PG&E's Sixth Renewable Auction Mechanism Power Purchase Agreements

I. Purpose

Pursuant to Decision ("D.") 14-11-042, Pacific Gas and Electric Company ("PG&E") hereby submits this Advice Letter, seeking approval of thirteen (13) Renewables Portfolio Standard ("RPS")-eligible power purchase agreements ("PPAs") executed between PG&E and seven sellers resulting from PG&E's Sixth Renewable Auction Mechanism Program ("RAM 6") solicitation.

II. Background

In D.14-11-042, the California Public Utilities Commission ("Commission" or "CPUC") directed the investor-owned utilities ("IOUs"), including PG&E, to conduct a RAM 6 solicitation as a "transitional auction" for a limited amount of additional renewable capacity.¹ In addition, the Commission also approved PG&E's proposal to roll-over capacity from its closed Photovoltaic ("PV") Program into the RAM 6 solicitation, as well as two subsequent solicitations.²

In D.15-01-051, the Commission directed the investor-owned utilities, including PG&E, to do advanced procurement for the Green Tariff Shared Renewables ("GTSR") program via RAM 6.³ The Commission set a minimum goal of 50 MW for PG&E with procurement to be complete within one year following the adoption of the Decision.

¹ D.14-11-042 at pp. 102-104, Ordering Paragraph ("OP") 31.

² *Id.* at pp. 104-105, OP 32.

³ D.15-01-051 at p. 27

III. Solicitation Summary

A. Solicitation Process

1. Design

On March 19, 2015, PG&E filed Advice Letter 4605-E seeking to update the RAM Request for Offers (“RFO”) Protocol and Appendices (including the guidelines for eligibility, overall procurement goals, and a description of the selection process). That advice letter was approved without modification on June 17, 2015, with an effective date of June 25, 2015. Under the approved RAM 6 Protocol, the primary guidelines for eligibility include:

- 1) Project size
 - a. RAM: greater than 3 MW up to 20 MW
 - b. GTSR: 0.5 MW up to 20 MW
- 2) Project location
 - a. RAM: PG&E, SCE or SDG&E service territory
 - b. GTSR: PG&E service territory
- 3) Seller must have a completed a System Impact Study, a Phase I interconnection study, or have documentation showing that the project passed the Wholesale Distribution Tariff or California Independent System Operator (“CAISO”) Fast Track screens. This requirement is waived for projects bidding into the three community buckets (A, B, and C) created by PG&E for this solicitation.
- 4) Seller must have previous experience constructing a project of a similar technology and capacity.
- 5) The project must be able to begin commercial operation within 24 months of CPUC final and non-appealable approval of the associated RAM PPA.
- 6) Existing facilities currently under contract may participate in the RFO provided that the existing contract terminates within 24 months of the expected date of CPUC approval of the RAM PPA.

After review by the Independent Evaluator (“IE”), all documents for the RAM 6 solicitation, including the Solicitation Protocol document, the PPA, and an Excel offer form with detailed instructions were posted at www.pge.com/rfo/RAM. The Excel offer form included an electronic signature whereby the Seller agreed to abide by the terms and conditions of the Protocol and to maintain confidentiality regarding their offer.

2. Process Overview

PG&E notified over 2,900 market participants (from PG&E’s normal distribution list) when the RAM 6 solicitation was launched on July 7, 2015. In addition, PG&E notified over 3,200 individuals from a list provided by PG&E’s California Solar Initiative team to garner interest

from developers for the community and environmental justice project sub-categories. The following timeline in the table below was adhered to:

Date/Time	Event
July 7, 2015	PG&E issued the RAM 6 RFO
July 14, 2015	Bidders' Webinar for RAM 6 RFO
August 21, 2015 no later than 12:00 P.M.(PPT)	Offers Due. Offer(s) must be submitted to the online platform at Power Advocate. All Projects must provide a completed Phase I or equivalent interconnection study with applicable appendices or showing that the project passed the WDAT/WDT or CAISO Fast Track screens. Projects must have a queue position and remain in the queue. Offer evaluation begins.
October 13, 2015	PG&E met with members of the Procurement Review Group ("PRG") concerning the RAM 6 RFO.
October 30, 2015	PG&E selected offers and notified Selected and Waitlist Participants.
November 4, 2015	Deadline for Selected and Waitlisted Participants to return signed acceptance letters.
November 5, 2015	Waitlisted Participants were notified if they had been selected.
November 10, 2015 no later than 1:00 P.M.(PPT)	Submittal of Signed PPA. Selected Participants that wished to continue participation in the RAM 6 RFO had to return a signed RAM PPA and required documentation as shown in Appendix VIII of the PPA to PG&E.
November 17, 2015 no later than 1:00 P.M.(PPT)	Selected Waitlisted Participants that wished to continue participation in the RAM 6 RFO had to return a signed RAM PPA with required documentation as shown in Appendix VIII to the RAM PPA.
December 18, 2015	<ul style="list-style-type: none"> PG&E executed 1 PPA designated for the RAM Program. PG&E executed 4 PPAs designated for the PV rollover program. PG&E executed 7 PPAs designated for the GTSR program.
January 8, 2016	PG&E executed 1 additional PPA designated for the GTSR program.

3. Bidders Webinar

PG&E held the Bidders' Webinar on July 14, 2015, with approximately 65 people attending via the internet or by phone. The Bidders' Webinar materials and an audio file of the conference are posted on PG&E's RAM website: www.pge.com/rfo/RAM.

The Bidders' Webinar covered the following major subjects: (1) introduction of the RAM Program which included the public disclosure of information, the procurement targets for this solicitation, updates from earlier RAM solicitations, and the role of the IE; (2) eligibility requirements to participate in this solicitation; (3) an overview of the PPA including the energy only and fully deliverable Time of Delivery ("TOD") factors; (4) the evaluation methodology used to select winning projects; (5) guidelines to submitting a successful proposal; (6) the offer submittal process and the required offer submission forms; (7) interconnection process; and (8) questions from webinar attendees.

No questions were asked by potential Participants during the Webinar. In addition, PG&E responded to email questions from bidders both before and after the Bidders' Webinar, and posted questions and answers of general interest on the website.

4. Offer Overview

PG&E received 90 offers for 48 unique facilities from 19 developers totaling 615 MW. The offers were separated into the three product categories (procurement targets in parentheses):

1. RAM: baseload (10 MW); as-available non-peaking (12 MW); and as-available peaking (10 MW)
2. PV Rollover: as-available peaking (105 MW)
3. GTSR: as-available peaking (50 MW). The GTSR category was further separated into the following sub-categories: Environmental Justice; Community A; Community B; Community C; and General GTSR.

The existing RAM Program rules provide flexibility for PG&E to procure plus or minus 20 MW per product category in the RAM and PV Rollover categories.

Participants submitting bids into the RFO had the option to bid their project as either energy-only ("EO"), partial capacity deliverability status ("PCDS"), or with full capacity deliverability status ("FCDS"). Projects that elected PCDS or FCDS were required to meet additional eligibility requirements which included having a completed Phase I deliverability study and be at a minimum in either the Phase II study for deliverability or Facilities Study. Projects that bid in as PCDS or FCDS must achieve deliverability status by the date indicated on their offer form.

B. Offer Evaluation

PG&E screened all offers on a "pass-fail" basis against the following eligibility requirements: project size; location; interconnection status; site control; developer experience; commercialized technology; and commercial operation date. Additional screens for the GTSR program ensured projects were located in identified environmental justice areas and the three community sub-categories established by PG&E.

Based on this initial screen, PG&E eliminated eleven (11) offers as non-conforming for not meeting the commercial operation date requirement. In addition, nine (9) offers were withdrawn by the developers prior to notification letters being sent out.

Conforming offers were then evaluated based on product category ranked by order of total cost. To get to a total cost, PG&E:

- applied appropriate TOD factors;
- levelized the prices;
- applied the transmission network upgrade costs taken from the interconnection study or interconnection agreement;
- gave PCDS and FCDS projects a Resource Adequacy (“RA”) value; and
- projects located in SP15 were given different values than projects located in NP15 due to RA capacity constraints.

For EO projects, the transmission network upgrade costs included only the costs associated with reliability network upgrades. For PCDS and FCDS offers, the reliability and deliverability network upgrade cost were included.

As part of its evaluation, PG&E assumed that all new resources bidding as partially or fully deliverable will achieve PCDS or FCDS by no later than the date indicated on their offer form, and the project’s maximum RA benefit was included beginning on that date through the remaining term. The RA benefits were evaluated by applying the monthly Net Qualifying Capacity to PG&E’s forecast of avoided capacity costs.

Finally, in recognition of PG&E’s commitment to Supplier Diversity and consistent with Resolution E-4414, PG&E took Supplier Diversity into consideration as a secondary criterion.

C. Offer Selection

Using the evaluation criteria described above, PG&E selected the least-cost offers while staying within the permitted product category targets. The list of executed contracts can be found in section E.2 below (Summary of Solicitation Selections). A more detailed description of the selection and execution process is contained in Confidential Appendix C.

D. RAM Contracts

A summary of some of the terms and conditions in PG&E’s approved RAM PPA used in the RAM 6 solicitation is included in the chart below. Please note that all capitalized terms not defined in the chart below have their meaning provided in the RAM PPA.

Key Contract Term	PG&E RAM PPA
Delivery Term	10, 15 or 20 years.
Eligibility	RAM: Existing and new projects within the IOUs’ service

Key Contract Term	PG&E RAM PPA
	territories. GTSR: New projects located within PG&E's service territory.
Contract Quantity	Participants in the solicitation are asked to provide a best estimate of annual deliveries as part of an Offer, which serves as a basis for the Guaranteed Energy Production ("GEP").
Commercial Operation Date	Must be commercially operable within 24 months of the final and non-appealable approval by the CPUC of the associated PPA, subject to the excused delays for permitting, transmission and force majeure.
Energy only or FCDS	Sellers have the option to bid in as energy only, partial capacity deliverability status, or full capacity deliverability status.
Performance Standards/ Requirements: Minimum production requirement	GEP = 160% of contract quantity measured over a two year period (as available non-peaking). 90% of expected contract quantity based on one year of rolling production (baseload). Small hydro projects are exempt from the minimum production requirement.
Scheduling Coordinator ("SC")	PG&E is the SC.
Excess Network Upgrade Costs Termination Right	Buyer has the right to terminate this Agreement within sixty (60) days after Seller provides to Buyer the results of any Interconnection Study, or interconnection agreement estimates, includes specifies, or reflects that the maximum total cost of the Network Upgrades to Buyer may in the aggregate exceed 110% of the amount identified in the Interconnection Studies that were submitted with Seller's original bid offer (package) so long as the exceeded dollar amount is equal to or greater than one hundred thousand dollars (\$100,000.00) ("Network Upgrades Cap"), and Seller has not agreed to assume financial responsibility for Excess Network Upgrade Costs.
Excess Network Upgrade Costs	Seller shall provide Buyer within ten (10) Business Days of receipt, copies of any Interconnection Study or the interconnection agreement that may give rise to a termination right of Buyer. Seller shall provide Buyer with a Notice of its irremovable election to exercise or not exercise its right to assume financial responsibility for any Excess Network Upgrade Cost. A failure to provide such an election deemed to be an election not to exercise such rights for purposes of administration and enforcement of the terms of this

Key Contract Term	PG&E RAM PPA
	Agreement.
Metering	Required to have a CAISO approved revenue meter.
WREGIS	<p>Seller shall, at its sole expense but subject to the Compliance Cost Cap (applicable to change-in-law only), take all action to ensure all WREGIS Certificates associated with all RECs corresponding to the Delivered Energy are issued and tracked for Buyer's sole benefit.</p> <p>Seller must transfer all Renewable Energy Credits ("RECs") associated with Delivered Energy, even if the Delivered Energy is not accepted and/or paid for because it is above the Contract Capacity or, for Baseload Product, paid for at a lower price because it is in excess of the scheduled energy (beyond tolerance band).</p>
Excess Sales	Seller has option to contract as full buy-sell or excess sales.
Curtailment	<p>Seller must curtail in response to CAISO, reliability coordinator, or Participating Transmission Owner curtailment. There is no limitation on curtailment of this type and no payment.</p> <p>Buyer may direct curtailment for any reason for unlimited hours per year. Buyer will pay Seller contract price for energy deemed delivered.</p>
Force Majeure	<p>"Force Majeure" includes any event or circumstance which wholly or partly prevents or delays the performance of any material obligation arising under this Agreement, but only if and to the extent (i) such event is not within the party invoking force majeure's reasonable control and the party has taken all reasonable precautions and measures in order to prevent or avoid such event or mitigate the effect of such event on such Party's ability to perform its obligations and such event is not the direct or indirect result of the negligence or the failure of, or caused by, the Party seeking to have its performance obligations excused thereby.</p> <p>(a) Subject to the foregoing, events that could qualify as Force Majeure include, but are not limited to, the following:</p> <p>(i) flooding, lightning, landslide, earthquake, or unusual or extreme adverse weather-related events;</p> <p>(ii) war (declared or undeclared), riot or similar civil disturbance;</p> <p>(iii) strikes, work stoppage or other labor disputes; or</p> <p>(iv) emergencies declared by the Transmission Provider successor or regional transmission organization or any state or federal regulator or legislature requiring a forced curtailment of the Project or making it impossible for the Transmission Provider to transmit</p>

Key Contract Term	PG&E RAM PPA
	<p>Energy</p> <p>(b) Force Majeure shall not be based on:</p> <p>(i) Buyer's inability economically to use or resell the Product purchased hereunder;</p> <p>(ii) Seller's ability to sell the Product at a price greater than the price set forth in this Agreement;</p> <p>(iii) Seller's inability to obtain permits or approvals of any type for the construction, operation, or maintenance of the Project;</p> <p>(iv) Seller's inability to obtain sufficient fuel, power or materials to operate the Project, except if Seller's inability to obtain sufficient fuel, power or materials is caused solely by an event of Force Majeure;</p> <p>(vi) a Forced Outage except where such Forced Outage is caused by an event of Force Majeure;</p> <p>(vii) a strike, work stoppage or labor dispute limited only to any one or more of Seller, Seller's Affiliates, the EPC Contractor or subcontractors thereof or any other third party employed by Seller to work on the Project;</p> <p>(viii) any equipment failure except if such equipment failure is caused solely by an event of Force Majeure;</p> <p>(ix) a Party's inability to pay amounts due to the other Party under this Agreement.</p>
Failure to Meet Guaranteed Commercial Operation Date	Six-month extension allowed in the event of Permitting Delay, Transmission Delay or Force Majeure. Notice of Permitting Delay or Transmission Delay required no later than 6 months after Effective Date. Notice of Force Majeure due as soon as possible.
Confidentiality	In general, non-public terms of the Agreement shall not be disclosed except to Affiliates, to Buyer's Procurement Review Group, in order to comply with any applicable law, regulation, or any exchange, control area or CAISO rule. Permitted disclosures expanded to include the number of bids per company, project size, contract capacity, and the achievement of project milestones.
Construction Start and Commercial Operation Certification Forms and Procedures	The Construction Start and Commercial Operation Certification Forms and Procedures are provided.
Credit—Project Development Security	<p>Sellers to post project development security prior to commercial operation:</p> <p>\$60/kW (As-available), \$90/kW (Baseload)</p>

Key Contract Term	PG&E RAM PPA
Credit—Delivery Term Security	Sellers to post delivery term security for the delivery term 5% of expected contract revenues.
Credit – Term Security	\$20/kW for GTSR Projects with Contract Capacity of three (3) MW and under multiplied by the capacity of the Project, within thirty (30) days following the Effective Date of the PPA until the end of the Term.

E. Solicitation Results

1. Summary of Solicitation Participation

Appendix G contains information on the results of PG&E's RAM 6 solicitation and Appendix H includes the location of the bids by county.

2. Summary of Solicitation Selections

The executed PPAs are summarized in the chart below. For purposes of this Advice Letter, all of the PPAs below are referred to as the "RAM 6 PPAs." For further information please refer to Appendices G and H:

Seller	Technology	Capacity (MW)	Location	Est. Annual Deliveries (GWh)	Commercial Operation Date (COD)	Term (years)	Program
GASNA 6P, LLC	PV	20.0	Helm	49.79	08/31/17	20	RAM
Java Solar, LLC	PV	13.5	Lemoore	35.94	08/31/17	20	PV
Bayshore Solar A, LLC	PV	20.0	Lancaster	57.02	08/31/17	20	PV
Bayshore Solar B, LLC	PV	20.0	Lancaster	57.02	08/31/17	20	PV
Bayshore Solar C, LLC	PV	20.0	Lancaster	57.02	08/31/17	20	PV
Western Grid Development LLC	PV	3.0	Los Banos	6.23	08/31/17	20	GTSR
GASNA 36P, LLC	PV	1.5	Helm	3.72	08/31/17	20	GTSR
54KR 8me LLC	PV	20.0	Unincorporated Kern	52.10	09/01/17	20	GTSR

Seller	Technology	Capacity (MW)	Location	Est. Annual Deliveries (GWh)	Commercial Operation Date (COD)	Term (years)	Program
			County				
RE Tranquillity 8 Amarillo LLC	PV	20.0	Cantua Creek	55.16	12/31/17	20	GTSR
Bakersfield PV 1, LLC	PV	5.25	Bakersfield	12.94	08/31/17	20	GTSR
Mirasol Development LLC	PV	1.0	Bakersfield	2.33	08/31/17	20	GTSR
Mirasol Development LLC	PV	1.0	McFarland	2.62	08/31/17	20	GTSR
Mirasol Development LLC	PV	1.0	Manteca	1.98	08/31/17	20	GTSR

D.11-12-052 requires that the IOUs make an upfront showing related to the portfolio content categorization of each proposed RPS procurement transaction. Specifically, for approval of contracts meeting the criteria of Public Utilities Code Section 399.16 (b)(1)(A) (“Portfolio Content Category One”), an IOU may show that the RPS-eligible generator has its first point of interconnection with the WECC transmission system within the boundaries of a California balancing authority area (“CBA”).⁴

Each of the RAM 6 PPAs satisfies the upfront showing required by D.11-12-052 for Portfolio Content Category One. Each PPA has or is expected to have its first point of interconnection within the metered boundaries of an IOU transmission or distribution system, within a CBA. Therefore, the RPS-eligible procurement from the PPAs satisfies the criteria for Portfolio Content Category One adopted in D.11-12-052.

In D.07-01-039, the Commission adopted an Emission Performance Standard (“EPS”) that applies to contracts for a term of five or more years for baseload generation with an annualized plant capacity factor of at least sixty (60) percent. The EPS does not apply to the RAM 6 PPAs because all thirteen generating facilities have a forecast annualized capacity factor of less than 60

⁴ See D.11-12-052 at pp. 40-41; See also *id.* at p. 37 (explaining that the upfront showing required of IOUs for procurement projected to meet Portfolio Content Category One based on the relevant point of interconnection would be “straightforwardly based on showing that the RPS-eligible generator has the applicable first point of interconnection.”).

percent and are therefore not baseload generation under Paragraphs 1(a)(11) and 3(2)(a) of the Adopted Interim EPS Rules.

IV. Information Regarding Previous RAM Solicitation PPAs

Consistent with the Decision and Resolutions E-4414, E-4489, E-4546, and E-4655 which require the IOUs to submit progress reports on project development milestones for contracts executed under the RAM Program, PG&E is also including a progress report for the contracts executed from the first five RAM solicitations in Appendix A, Table 7.

V. Request for Commission Approval

PG&E requests the Commission approve the RAM 6 PPAs through an Energy Division disposition letter issued within 30 days of the filing of this Advice Letter (by February 21, 2016), including adoption of the following findings of fact and conclusions of law:⁵

1. Each of the RAM 6 PPAs should be approved in its entirety, including payments to be made by PG&E pursuant to each PPA, subject to the Commission's review of PG&E's administration of the PPA;
2. A finding that the selection of the RAM 6 PPAs was consistent with PG&E's approved RAM Program Solicitation protocol, and that the terms of each PPA, including the price of delivered energy, are reasonable and prudent;
3. A finding that any procurement pursuant to the RAM 6 PPAs constitutes procurement from an eligible renewable energy resource for purposes of determining PG&E's compliance with any obligation or target that it may have to procure eligible renewable energy resources pursuant to the California RPS (Public Utilities Code Section 399.11 et seq.), D.03-06-071, D.06-10-050, D.10-12-048, D.11-12-020, D.11-12-052, Resolution E-4414, or other applicable law;
4. A finding that, subject to after-the-fact verification that all applicable criteria have been met, the Energy Division accepts PG&E's upfront showing that deliveries from the RAM 6 PPAs should be categorized as procurement under the portfolio content category specified in Public Utilities Code Section 399.16 (b)(1)(A);
5. Adopts the following findings with respect to resource compliance with the EPS adopted in R.06-04-009:
 - a. The RAM 6 PPAs are not subject to the EPS because each of the respective generating facilities has a forecast capacity factor of less than 60 percent and,

⁵ If the Energy Division disposition does not include explicit findings and conclusions, the approval of this advice letter shall be deemed to include approval of the requested findings and conclusions.

therefore, is not baseload generation under Paragraphs 1(a)(ii) and 3(2)(a) of the Adopted Interim EPS Rules; and

- b. A finding that PG&E has provided the notice of procurement required by D.06-01-038 in this Advice Letter filing; and
- 6. A finding that all procurement and administrative costs, as provided by Public Utilities Code section 399.14(g), associated with the RAM 6 PPAs shall be recovered in rates and all of the utility's costs under the RAM 6 PPAs shall be recovered through PG&E's Energy Resource Recovery Account and to recover any stranded costs consistent with D.08-09-012.

VI. Request for Confidential Treatment

In support of this Advice Letter, PG&E has provided the following confidential information: the executed RAM 6 PPAs and other information that more specifically describes the rights and obligations of the parties, and the confidential results of the solicitation. This information is being submitted in the manner directed by D.08-04-023 to demonstrate the confidentiality of material and to invoke the protection of confidential utility information provided under either the terms of the IOU Matrix, Appendix 1 of D.06-06-066 and Appendix C of D.08-04-023, or General Order 66-C. A separate Declaration Seeking Confidential Treatment is being filed concurrently with this Advice Letter.

Confidential Attachments:

- Confidential Appendix A: Solicitation Data and Project Development Milestones for Executed Contracts (Redacted version included with public filing)
- Confidential Appendix C: Valuation Process Summary
- Confidential Appendix D: Analysis of Customer Benefits
- Confidential Appendix E: Independent Evaluator Report (Redacted version included with public filing)
- Confidential Appendix F: Executed Contracts and Letters of Concurrence

Protests

Anyone wishing to protest this filing may do so by letter sent via U.S. mail, facsimile or E-mail, no later than February 11, 2016, which is 20 days after the date of this filing. Protests must be submitted to:

CPUC Energy Division
ED Tariff Unit
505 Van Ness Avenue, 4th Floor
San Francisco, California 94102

Facsimile: (415) 703-2200
E-mail: EDTariffUnit@cpuc.ca.gov

Copies of protests also should be mailed to the attention of the Director, Energy Division, Room 4004, at the address shown above.

The protest shall also be sent to PG&E either via E-mail or U.S. mail (and by facsimile, if possible) at the address shown below on the same date it is mailed or delivered to the Commission:

Eric Jacobson
Director, Regulatory Relations
c/o Megan Lawson
Pacific Gas and Electric Company
77 Beale Street, Mail Code B10C
P.O. Box 770000
San Francisco, California 94177

Facsimile: (415) 973-7226
E-mail: PGETariffs@pge.com

Any person (including individuals, groups, or organizations) may protest or respond to an advice letter (General Order 96-B, Section 7.4). The protest shall contain the following information: specification of the advice letter protested; grounds for the protest; supporting factual information or legal argument; name, telephone number, postal address, and (where appropriate) e-mail address of the protestant; and statement that the protest was sent to the utility no later than the day on which the protest was submitted to the reviewing Industry Division (General Order 96-B, Section 3.11).

VII. Tier Designation

PG&E is designating this as a Tier 2 Advice Letter, in accordance with D.10-12-048 and Resolution E-4414.

VIII. Effective Date

Accordingly, PG&E requests that the Energy Division issue a disposition approving PG&E's RAM 6 PPAs within the initial review period, which will expire within 30 days of the filing of this Advice Letter (by February 21, 2016). Pursuant to General Order 96-B, the advice letter will be effective upon approval.

IX. Notice

In accordance with General Order 96-B, Section IV, a copy of this advice letter is being sent electronically and via U.S. mail to parties shown on the attached list and the service lists for R.15-02-020 and A.12-01-008, et al.. Address changes to the General Order 96-B list and electronic approvals should be directed to PGETariffs@pge.com. For changes to any other service list, please contact the Commission's Process Office at (415) 703-2021 or at

Process_Office@cpuc.ca.gov. Advice letter filings can also be accessed electronically at:
<http://www.pge.com/tariffs>.

/S/

Erik Jacobson
Director – Regulatory Relations

cc: Paul Douglas – Energy Division
Megha Lakhchaura – Energy Division
Service Lists for R.15-02-020 and GTSR A.12-01-008, et al.

Limited Access to Confidential Material:

The portions of this Advice Letter marked Confidential Protected Material are submitted under the confidentiality protection of Section 583 and 454.5(g) of the Public Utilities Code and General Order 66-C. This material is protected from public disclosure because it consists of, among other items, the contracts themselves and price information of a proposed RPS-eligible RAM contract, which are protected pursuant to D.06-06-066 and D.08-04-023. A separate Declaration seeking Confidential Treatment regarding the confidential information is filed concurrently herewith.

Attachments:

Confidential Appendix A:	Solicitation Data and Project Development Milestones for Executed Contracts (Redacted version included with public filing)
Appendix B:	PG&E's RAM Standard Contract
Confidential Appendix C:	Valuation Process Summary
Confidential Appendix D:	Analysis of Customer Benefits
Confidential Appendix E:	Independent Evaluator Report (Redacted version included with public filing)
Confidential Appendix F:	Executed Contracts
Appendix G:	Summary of Solicitation Participation
Appendix H:	Location of Bids

CALIFORNIA PUBLIC UTILITIES COMMISSION

ADVICE LETTER FILING SUMMARY ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No. **Pacific Gas and Electric Company (ID U39 E)**

Utility type:

☒ ELC

☐ GAS

☐ PLC

☐ HEAT

☐ WATER

Contact Person: Jennifer Wirowek

Phone #: (415) 973-1419

E-mail: J6WS@pge.com and PGETariffs@pge.com

EXPLANATION OF UTILITY TYPE

ELC = Electric

GAS = Gas

PLC = Pipeline

HEAT = Heat

WATER = Water

(Date Filed/ Received Stamp by CPUC)

Advice Letter (AL) #: **4780-E**

Tier: 2

Subject of AL: **Advice Letter Filing of PG&E's Sixth Renewable Auction Mechanism Power Purchase Agreements**

Keywords (choose from CPUC listing): Compliance, Contracts, Portfolio

AL filing type: ☐ Monthly ☐ Quarterly ☐ Annual ☒ One-Time ☐ Other _____

If AL filed in compliance with a Commission order, indicate relevant Decision/Resolution #: D.14-11-042

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL: No

Summarize differences between the AL and the prior withdrawn or rejected AL: _____

Is AL requesting confidential treatment? If so, what information is the utility seeking confidential treatment for: Yes

Confidential information will be made available to those who have executed a nondisclosure agreement: Yes

Name(s) and contact information of the person(s) who will provide the nondisclosure agreement and access to the confidential information: Chris DiGiovanni (415) 973-4656

Resolution Required? ☐ Yes ☒ No

Requested effective date: **February 21, 2016**

No. of tariff sheets: N/A

Estimated system annual revenue effect (%): N/A

Estimated system average rate effect (%): N/A

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting). N/A

Tariff schedules affected: N/A

Service affected and changes proposed: N/A

Pending advice letters that revise the same tariff sheets: N/A

Protests, dispositions, and all other correspondence regarding this AL are due no later than 20 days after the date of this filing, unless otherwise authorized by the Commission, and shall be sent to:

California Public Utilities Commission

Energy Division

EDTariffUnit

505 Van Ness Ave., 4th Flr.

San Francisco, CA 94102

E-mail: EDTariffUnit@cpuc.ca.gov

Pacific Gas and Electric Company

Attn: Erik Jacobson

Director, Regulatory Relations

c/o Megan Lawson

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Confidentiality Declaration & Matrix

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

**DECLARATION OF CHRIS DIGIOVANNI
SEEKING CONFIDENTIAL TREATMENT
FOR CERTAIN DATA AND INFORMATION
CONTAINED IN ADVICE LETTER 4780-E**

I, Chris DiGiovanni, declare:

1. I am a Manager in the Competitive Solicitations department within Energy Policy and Procurement at Pacific Gas and Electric Company (PG&E). In this position, my responsibilities include management of PG&E's Renewable Auction Mechanism (RAM) program. This declaration is based on my personal knowledge of PG&E's practices and my understanding of the Commission's decisions protecting the confidentiality of market-sensitive information.

2. Based on my knowledge and experience, and in accordance with the Decisions 06-06-066, 08-04-023, and relevant Commission rules, I make this declaration seeking confidential treatment for certain data and information contained in PG&E's Advice Letter 4780-E submitted on January 22, 2016.

3. Attached to this declaration is a matrix identifying the data and information for which PG&E is seeking confidential treatment. The matrix specifies that the material PG&E is seeking to protect constitutes confidential market sensitive data and information covered by D.06-06-066. The attached matrix also specifies why confidential protection is justified. Further, the data and information: (1) is not already public; and (2) cannot be aggregated, redacted, summarized or otherwise protected in a way that allows partial disclosure. By this reference, I am incorporating into this declaration all of the explanatory text that is pertinent to my testimony in the attached matrix.

I declare under penalty of perjury, under the laws of the State of California, that the foregoing is true and correct. Executed on January 22, 2016 at San Francisco, California.



CHRIS DIGIOVANNI

PACIFIC GAS AND ELECTRIC COMPANY (U 39 E)

ADVICE LETTER 4780-E

January 22, 2016

IDENTIFICATION OF CONFIDENTIAL INFORMATION

Redaction Reference	Category from D.06-06-066, Appendix 1, or Separate Confidentiality Order That Data Corresponds To	Justification for Confidential Treatment	Length of Time Data To Be Kept Confidential
Document: Advice Letter 4780-E (and Appendices)			
Appendix A (Solicitation Data and Project Development Milestones) – gray shaded areas	VIII.B – Quantitative analysis for scoring and evaluating bids	Confidential quantitative analysis for scoring and evaluating bids in solicitation	Three years after winning bidders selected
Appendix C (Valuation Process Summary) – in its entirety	VIII.B – Quantitative analysis for scoring and evaluating bids	Confidential quantitative analysis for scoring and evaluating bids in solicitation	Three years after winning bidders selected
Appendix D (Analysis of Customer Benefits and NMV) – in its entirety including attachment	VII.G – Terms and conditions of RPS contracts not eligible for Supplemental Energy Payments	Confidential terms and conditions of RPS contract that is not eligible for Supplemental Energy Payments.	Three years from contract date for deliveries to start or one year after expiration.
	VII – Score sheets, analysis and evaluation for RPS Projects	Confidential score sheets, analyses and evaluation for RPS contract.	Three years
	VIII.B – Quantitative analysis for scoring and evaluating bids	Confidential quantitative analysis for scoring and evaluating bids in solicitation	Three years after winning bidders selected

PACIFIC GAS AND ELECTRIC COMPANY (U 39 E)

ADVICE LETTER 4780-E

January 22, 2016

IDENTIFICATION OF CONFIDENTIAL INFORMATION

Redaction Reference	Category from D.06-06-066, Appendix 1, or Separate Confidentiality Order That Data Corresponds To	Justification for Confidential Treatment	Length of Time Data To Be Kept Confidential
Appendix E (Independent Evaluator Report) – gray shaded areas	VII.G – Terms and conditions of RPS contracts not eligible for Supplemental Energy Payments VII – Score sheets, analysis and evaluation for RPS Projects VIII.B – Quantitative analysis for scoring and evaluating bids	Confidential terms and conditions of RPS contract that is not eligible for Supplemental Energy Payments. Confidential score sheets, analyses and evaluation for RPS contract. Confidential quantitative analysis for scoring and evaluating bids in solicitation	Three years from contract date for deliveries to start or one year after expiration. Three years Three years after winning bidders selected
Appendix F (Executed PPAs and Letters of Concurrence) – in its entirety	VII.G – Terms and conditions of RPS contracts not eligible for Supplemental Energy Payments	Confidential terms and conditions of RPS contract that is not eligible for Supplemental Energy Payments.	Three years from contract date for deliveries to start or one year after expiration

Appendix A

Solicitation Data and Project Development Milestones for Executed Contracts

(Redacted version included with public filing)

Table 1. Overview of RAM 6 RFO

Seller's (Developer's) Name	Number of bids submitted	Full Capacity project	Energy Only project	Number of bids shortlisted	Number of executed contracts
8minutenergy Renewables, LLC	1			N/A	1
Apex Natural Renewable Generation, LLC	1			N/A	
Colemko, LLC	1			N/A	
Del Sol NRG, Inc.	3			N/A	
E.ON	6			N/A	
EDF Renewable Development	5			N/A	
First Solar, Inc.	8			N/A	
FTP Power LLC, dba Sustainable Power Group (sPower)	5			N/A	3
Green Light Energy Corp.	6			N/A	1
Mega Point Energy, LLC	1			N/A	
Mirasol Development LLC	21			N/A	4
New Dimension Energy Company, LLC	1			N/A	
Recurrent Energy	18			N/A	1
Republic Services	2			N/A	
Solar Frontier Americas Development, LLC	4			N/A	2
SolarGen USA LLC (together with GCL Solar Energy, Inc.)	2			N/A	
SunEdison Utility Solutions, LLC	1			N/A	
SunPower Corporation	3			N/A	1
W Power, LLC	1			N/A	

Note: Given the structure of the RAM program, the concept of a shortlist is not applicable.

Table 2. Overview of RAM 6 RFO by Capacity

	Contract Size (MW)	Number of Bids Submitted	Number of Bids Shortlisted	Number of executed contracts
1	0.5-5	28	N/A	5
2	>5-10	13	N/A	1
3	>10-15	6	N/A	1
4	>15-20	43	N/A	6

Note: Given the structure of the RAM program, the concept of a shortlist is not applicable.

Table 3. Overview of RAM 6 RFO by Technology

	Participating Technology	Number of Bids Submitted	Number of Bids Shortlisted	Number of executed contracts
1	Solar PV	83	N/A	13
2	Wind	5	N/A	0
3	Landfill Gas	2	N/A	0
4	Geothermal	0	N/A	0
5	Biogas	0	N/A	0
6	Biomass	0	N/A	0
7	Small Hydro	0	N/A	0

Note: Given the structure of the RAM program, the concept of a shortlist is not applicable.

Table 4. Overview of RAM 6 RFO

Technology Type	Total # of Bids into RFO	Total # of Eligible Bids	Total # of Bids Shortlisted	Total # of Executed Contracts	Mean RFO Bid Size (MW)	Mean Shortlist Bid Size (MW)	Mean Contract Size (MW)	No. of RFO Bids that Failed Each Viability Screen				
								Dev. Exp.	Site Control	Commercialized Tech.	Interconnection	COD >24 mos
1 Solar PV	83	72	N/A	13	11.6	N/A	11.25	0	2	0	9	0
2 Wind	5	5	N/A	0	18.3	N/A	0.0	0	0	0	0	0
3 Landfill Gas	2	2	N/A	0	6.0	N/A	0.0	0	0	0	0	0
4 Geothermal	0	0	N/A	0	0.0	N/A	0.0	0	0	0	0	0
5 Biomass	0	0	N/A	0	0.0	N/A	0.0	0	0	0	0	0
6 Biogas	0	0	N/A	0	0.0	N/A	0.0	0	0	0	0	0
7 Small Hydro	0	0	N/A	0	0.0	N/A	0.0	0	0	0	0	0

Note: Given the structure of the RAM program, the concept of the shortlist is not applicable.

Table 5. All Bids

Net Market Value Overview by Project Size (MW)						
	RAM RFO			RAM Shortlist		
	Min.	Max.	Mean	Min.	Max.	Mean
0.5-5				N/A	N/A	N/A
>5-10				N/A	N/A	N/A
>10-15				N/A	N/A	N/A
>15-20				N/A	N/A	N/A

Table 6. All Bids

Net Market Value Overview by Technology Type						
	RAM RFO			RAM Shortlist		
	Min.	Max.	Mean	Min.	Max.	Mean
Solar PV				N/A	N/A	N/A
Wind				N/A	N/A	N/A
Landfill Gas				N/A	N/A	N/A
Geothermal				N/A	N/A	N/A
Biogas				N/A	N/A	N/A
Biomass				N/A	N/A	N/A
Small Hydro				N/A	N/A	N/A

Note: Given the structure of the RAM program, the concept of the shortlist is not applicable.

Table 7. Project Development Milestones for Executed RAM Contracts

Table 1. Overview of RAM 6 RFO											Regulatory		
Project Name	Contract Manager	Company Name (Parent Company/Developer)	Project Status (Delayed/On Schedule)	Product Category	Technology Type	Location (City / County)	RAM RFO Number	Original Bid Capacity (MW)	Installed Capacity (MW)	Full Buy/Sell or Excess Sales	CPUC Non-Appellable Approval Date	6-Month Regulatory Delay (Yes/No)	Reason for Reg. Delay
Mammoth G3	Ryan Susanto	Ormat Technologies, Inc.	Online	Baseload	Geothermal	Mammoth Lakes / Mono	RAM 1 RFO	14	14	Excess Sales	5/14/2012	No	N/A
West Antelope	Ryan Susanto	Dominion Solar Holdings, Inc.	Online	As Available Peaking	Solar Photovoltaic	Lancaster / Los Angeles	RAM 1 RFO	20	20	Full Buy/Sell	5/14/2012	Yes	Transmission Delay
Western Antelope Blue Sky Ranch A	Ryan Susanto	FTP Solar LLC	Online	As Available Peaking	Solar Photovoltaic	Lancaster / Los Angeles	RAM 1 RFO	20	20	Full Buy/Sell	5/14/2012	Yes	Transmission Delay
Wind Resource I	Ryan Susanto	Calwind Resources, Inc.	Online	As Available Non Peaking	Wind	Tehachapi / Kern	RAM 1 RFO	8.71	8.71	Full Buy/Sell	5/14/2012	No	N/A
White River Solar 2	Andrew Salinas	Con Edison Development	Online	As Available Peaking	Solar Photovoltaic	Alpaugh / Tulare	RAM 2 RFO	19.75	19.75	Full Buy/Sell	11/20/2012	No	N/A
Mammoth G1	Ryan Susanto	Ormat Technologies, Inc.	Online	Baseload	Geothermal	Mammoth Lakes / Mono	RAM 2 RFO	7.5	7.5	Excess Sales	11/20/2012	No	N/A
Wind Resource II	Ryan Susanto	Calwind Resources, Inc.	Online	As Available Non Peaking	Wind	Tehachapi / Kern	RAM 2 RFO	19.955	19.955	Full Buy/Sell	11/20/2012	No	N/A
Columbia Solar Energy	Paul Krebs	Pacific Service Enterprise Group	Online	As Available Peaking	Solar Photovoltaic	Pittsburg / Contra Costa	RAM 2 RFO	19	19	Full Buy/Sell	11/20/2012	Yes	Transmission Delay
Alamo Solar, LLC	Norman Lopez	Dominion Solar Holdings, Inc.	Online	As Available Peaking	Solar Photovoltaic	Oro Grande / San Bernardino	RAM 2 RFO	20	20	Full Buy/Sell	11/20/2012	Yes	Transmission Delay
CID Solar PV Project	Ryan Susanto	Dominion Solar Holdings, Inc.	Online	As Available Peaking	Solar Photovoltaic	Corcoran / Kings	RAM 2 RFO	19.76	19.76	Full Buy/Sell	11/20/2012	Yes	Transmission Delay
Sand Hill Wind	Bella Shamoun	Ogin Inc.	Delayed	As Available Non Peaking	Wind	Tracy / San Joaquin	RAM 3 RFO	20	20	Full Buy/Sell	6/10/2013	Yes	Transmission Delay
RE Old River One	Ryan Susanto	Dominion Solar Holdings, Inc.	Online	As Available Peaking	Solar Photovoltaic	Bakersfield / Kern	RAM 3 RFO	20	20	Full Buy/Sell	6/10/2013	No	N/A
Shafter Solar	Ryan Susanto	NextEra Energy Resources, LLC	Online	As Available Peaking	Solar Photovoltaic	Shafter / Kern	RAM 3 RFO	19.98	19.98	Full Buy/Sell	6/10/2013	Yes	Transmission Delay
Morelos Del Sol	Fish Lakew	Southern Turner Renewable Energy, LLC	On Schedule	As Available Peaking	Solar Photovoltaic	Lost Hills / Kern	RAM 3 RFO	15	15	Full Buy/Sell	6/10/2013	Yes	Transmission Delay
Rising Tree Wind Farm II LLC	Mike Wilson	EDP Renewables North America LLC	Online	As Available Non Peaking	Wind	Mojave / Kern	RAM 4 RFO	19.8	19.8	Full Buy/Sell	2/3/2014	No	N/A
Kokawaka Creek Hydroelectric Facility	Dennis Dyc-O Neal	Ares Management	Online	As Available Non Peaking	Hydro: Small	Zenia / Trinity and Humboldt	RAM 4 RFO	5.5	5.5	Full Buy/Sell	2/3/2014	No	N/A
Woodmere Solar Farm	Mike Wilson	Sustainable Power Group LLC	On Schedule	As Available Peaking	Solar Photovoltaic	Bakersfield / Kern	RAM 4 RFO	15	15	Full Buy/Sell	2/3/2014	No	N/A
CED Lost Hills Solar	Kelly Johnston	Con Edison Development	On Schedule	As Available Peaking	Solar Photovoltaic	Lost Hills / Kern	RAM 4 RFO	20	20	Full Buy/Sell	2/3/2014	Yes	Permitting Delay
Maricopa West Solar PV 2	Andrew Salinas	E.ON Climate and Renewables North America, LLC	On Schedule	As Available Peaking	Solar Photovoltaic	Maricopa / Kern	RAM 5 RFO	20	20	Full Buy/Sell	4/20/24	No	N/A
Portal Ridge Solar C Project	Bella Shamoun	First Solar, Inc.	On Schedule	As Available Peaking	Solar Photovoltaic	Lancaster / Los Angeles	RAM 5 RFO	11.4	11.4	Full Buy/Sell	4/20/24	No	N/A
SR Solis Oro Loma Teresina Solar Project A	Mike Wilson	Con Edison Development	On Schedule	As Available Peaking	Solar Photovoltaic	Unincorporated Fresno County / Fresno	RAM 5 RFO	10	10	Full Buy/Sell	4/20/24	No	N/A
Sunray 2D	Norman Lopez	Cogentrix Solar Holdings, LLC	On Schedule	As Available Peaking	Solar Photovoltaic	Daggett / San Bernardino	RAM 5 RFO	20	20	Full Buy/Sell	4/20/24	No	N/A
SR Solis Rocket Solar Project A	Mike Wilson	Con Edison Development	On Schedule	As Available Peaking	Solar Photovoltaic	Avenal / Kings	RAM 5 RFO	7.9	7.9	Full Buy/Sell	4/20/24	No	N/A
SR Solis Oro Loma Teresina Solar Project B	Mike Wilson	Con Edison Development	On Schedule	As Available Peaking	Solar Photovoltaic	Unincorporated Fresno County / Fresno	RAM 5 RFO	10	10	Full Buy/Sell	4/20/24	No	N/A
Altech III	Bella Shamoun	Ogin Inc.	On Schedule	As Available Non Peaking	Wind	Palm Springs / Riverside	RAM 5 RFO	20	20	Full Buy/Sell	4/20/24	No	N/A
SR Solis Rocket Solar Project B	Mike Wilson	Con Edison Development	On Schedule	As Available Peaking	Solar Photovoltaic	Avenal / Kings	RAM 5 RFO	7.9	7.9	Full Buy/Sell	4/20/24	No	N/A
Bakersfield 1	Fish Lakew	Miraast Development LLC	On Schedule	As Available Peaking	Solar Photovoltaic	BAKERSFIELD	RAM 6 RFO	5.25	5.25	Full Buy/Sell	TBD	No	N/A
Bayshore South A LLC	Bella Shamoun	FTP Power LLC, dba Sustainable Power Group (sPower)	On Schedule	As Available Peaking	Solar Photovoltaic	Lancaster	RAM 6 RFO	20	20	Full Buy/Sell	TBD	No	N/A
Bayshore South B LLC	Bella Shamoun	FTP Power LLC, dba Sustainable Power Group (sPower)	On Schedule	As Available Peaking	Solar Photovoltaic	Lancaster	RAM 6 RFO	20	20	Full Buy/Sell	TBD	No	N/A
Bayshore South C LLC	Bella Shamoun	FTP Power LLC, dba Sustainable Power Group (sPower)	On Schedule	As Available Peaking	Solar Photovoltaic	Lancaster	RAM 6 RFO	20	20	Full Buy/Sell	TBD	No	N/A

Table 7. Project Development Milestones for Executed RAM Contracts

Table 1. Overview of RAM 6 RFO											Regulatory		
Project Name	Contract Manager	Company Name (Parent Company/Developer)	Project Status (Delayed/On Schedule)	Product Category	Technology Type	Location (City / County)	RAM RFO Number	Original Bid Capacity (MW)	Installed Capacity (MW)	Full Buy/Sell or Excess Sales	CPUC Non-Appellable Approval Date	6-Month Regulatory Delay (Yes/No)	Reason for Reg. Delay
GASNA 36P, LLC ("San Joaquin 18 RT")	Mike Wilson	Solar Frontier Americas Development, LLC	On Schedule	As Available Peaking	Solar Photovoltaic	Helm	RAM 6 RFO	1.5	1.5	Full Buy/Sell	TBD	No	N/A
GASNA 6P, LLC ("San Joaquin 14")	Mike Wilson	Solar Frontier Americas Development, LLC	On Schedule	As Available Peaking	Solar Photovoltaic	Helm	RAM 6 RFO	20	20	Full Buy/Sell	TBD	No	N/A
Bakersfield Industrial 1	Dennis Dyc-O Neal	Mirasol Development LLC	On Schedule	As Available Peaking	Solar Photovoltaic	BAKERSFIELD	RAM 6 RFO	1	1	Full Buy/Sell	TBD	No	N/A
Delano Land 1	Dennis Dyc-O Neal	Mirasol Development LLC	On Schedule	As Available Peaking	Solar Photovoltaic	McFarland	RAM 6 RFO	1	1	Full Buy/Sell	TBD	No	N/A
Manteca Land 1	Dennis Dyc-O Neal	Mirasol Development LLC	On Schedule	As Available Peaking	Solar Photovoltaic	MANTECA	RAM 6 RFO	1	1	Full Buy/Sell	TBD	No	N/A
Merced 1	Andrew Salinas	Green Light Energy Corp.	On Schedule	As Available Peaking	Solar Photovoltaic	Los Banos	RAM 6 RFO	3	3	Full Buy/Sell	TBD	No	N/A
Tranquility 8 Amarillo	Andrew Salinas	Recurrent Energy	On Schedule	As Available Peaking	Solar Photovoltaic	Canby Creek	RAM 6 RFO	20	20	Full Buy/Sell	TBD	No	N/A
Java Solar Project	Paul Krebs	SunPower Corporation	On Schedule	As Available Peaking	Solar Photovoltaic	Lemoore	RAM 6 RFO	13.5	13.5	Full Buy/Sell	TBD	No	N/A
54KR	Mike Wilson	8minutenergy Renewables, LLC	On Schedule	As Available Peaking	Solar Photovoltaic	Unincorporated Kern County	RAM 6 RFO	20	20	Full Buy/Sell	TBD	No	N/A

Table 7. Project Development Milestones for Executed RAM Contracts

Project Name	Contract Manager	Company Name (Parent Company/Developer)	Commercial Operation Date			Necessary Permitting and Government Approvals				Interconnection (IC) Status		
			Contract GCOD	Actual COD	Construction Started (Y/N)	Necessary Permits/Govt. Approvals Received (Y/N)	Necessary Permits/Govt. Approvals Filed (Y/N)	If Filed, Expected Date for Permits/Govt. Approval	If not Filed, Expected File Date	IC Agreement Signed (Y/N)	IC Application Deemed Complete (Y/N)	Stage in IC Process (Study/Agreement/Construction)
Mammoth G3	Ryan Susanto	Ormat Technologies, Inc.	11/14/2013	4/1/2013	N/A (Existing)	Y	Y	Complete	N/A	Y	Y	Agreement
West Antelope	Ryan Susanto	Dominion Solar Holdings, Inc.	5/14/2014	11/11/2014	Y	Y	Y	Complete	N/A	Y	Y	Agreement
Western Antelope Blue Sky Ranch A	Ryan Susanto	FTP Solar LLC	5/14/2014	11/14/2014	Y	Y	Y	Complete	N/A	Y	Y	Agreement
Wind Resource I	Ryan Susanto	Calwind Resources, Inc.	11/14/2013	12/17/2012	N/A (Existing)	Y	Y	Complete	N/A	Y	Y	Agreement
White River Solar 2	Andrew Salinas	Con Edison Development	11/20/2014	10/2/2014	Y	Y	Y	Complete	N/A	Y	Y	Agreement
Mammoth G1	Ryan Susanto	Ormat Technologies, Inc.	11/20/2014	12/26/2013	N/A (Existing)	Y	Y	Complete	N/A	Y	Y	Agreement
Wind Resource II	Ryan Susanto	Calwind Resources, Inc.	11/20/2014	9/10/2013	N/A (Existing)	Y	Y	Complete	N/A	Y	Y	Agreement
Columbia Solar Energy	Paul Krebs	Pacific Service Enterprise Group	5/20/2015	10/21/2015	Y	Y	Y	Complete	N/A	Y	Y	Agreement
Alamo Solar, LLC	Norman Lopez	Dominion Solar Holdings, Inc.	5/20/2015	5/20/2015	Y	Y	Y	Complete	N/A	Y	Y	Agreement
CID Solar PV Project	Ryan Susanto	Dominion Solar Holdings, Inc.	2/24/2015	1/20/2015	Y	Y	Y	Complete	N/A	Y	Y	Agreement
Sand Hill Wind	Bella Shamoun	Ogin Inc.	12/10/2015	TBD	N	Y	Y	Complete	N/A	N	N	Study
RE Old River One	Ryan Susanto	Dominion Solar Holdings, Inc.	6/10/2015	12/30/2014	Y	Y	Y	Complete	N/A	Y	Y	Agreement
Shafter Solar	Ryan Susanto	NextEra Energy Resources, LLC	10/10/2015	6/3/2015	Y	Y	Y	Complete	N/A	Y	Y	Agreement
Morelos Del Sol	Fish Lakew	Southern Turner Renewable Energy, LLC	12/10/2015	12/2/2015	Y	Y	Y	Complete	N/A	Y	Y	Agreement
Rising Tree Wind Farm II LLC	Mike Wilson	EDP Renewables North America LLC	2/3/2016	8/7/2015	Y	Y	Y	Complete	N/A	Y	Y	Agreement
Kekawaka Creek Hydroelectric Facility	Dennis Dyc-O Neal	Ares Management	12/1/2013	6/1/2015	N/A (Existing)	Y	Y	Complete	N/A	Y	Y	Agreement
Woodmere Solar Farm	Mike Wilson	Sustainable Power Group LLC	2/3/2016	12/23/2015	Y	Y	Y	Complete	N/A	Y	Y	Agreement
CEI Lost Hills Solar	Kelly Johnston	Con Edison Development	8/3/2016	TBD	N	Y	Y	Complete	N/A	Y	Y	Agreement
Maricopa West Solar PV 2	Andrew Salinas	E.ON Climate and Renewables North America, LLC	1/20/2017	TBD	N	Y	Y	Complete	N/A	N	Y	Study
Portal Ridge Solar C Project	Bella Shamoun	First Solar, Inc.	1/20/2017	TBD	N	Y	Y	Complete	N/A	Y	Y	Agreement
SR Solis Oro Loma Teresina Solar Project A	Mike Wilson	Con Edison Development	1/20/2017	TBD	N	N	Y	8/1/2015	N/A	Y	Y	Agreement
Sunray 2D	Norman Lopez	Cogentrix Solar Holdings, LLC	1/20/2017	TBD	N	Y	Y	Complete	N/A	Y	Y	Agreement
SR Solis Rocket Solar Project A	Mike Wilson	Con Edison Development	1/20/2017	TBD	N	N	Y		N/A	Y	Y	Agreement
SR Solis Oro Loma Teresina Solar Project B	Mike Wilson	Con Edison Development	1/20/2017	TBD	N	N	Y	8/1/2015	N/A	Y	Y	Agreement
Altech III	Bella Shamoun	Ogin Inc.	1/20/2017	TBD	N	N	Y	3/31/2016	N/A	N	Y	Study
SR Solis Rocket Solar Project B	Mike Wilson	Con Edison Development	1/20/2017	TBD	N	N	Y	8/1/2015	N/A	Y	Y	Agreement
Bakersfield 1	Fish Lakew	Mirasol Development LLC	24 Months from CPUC Approval	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD
Bayshore South A LLC	Bella Shamoun	FTP Power LLC, dba Sustainable Power Group (sPower)	24 Months from CPUC Approval	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD
Bayshore South B LLC	Bella Shamoun	FTP Power LLC, dba Sustainable Power Group (sPower)	24 Months from CPUC Approval	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD
Bayshore South C LLC	Bella Shamoun	FTP Power LLC, dba Sustainable Power Group (sPower)	24 Months from CPUC Approval	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD

Table 7. Project Development Milestones for Executed RAM Contracts

			Commercial Operation Date			Necessary Permitting and Government Approvals				Interconnection (IC) Status		
Project Name	Contract Manager	Company Name (Parent Company/Developer)	Contract GCOD	Actual COD	Construction Started (Y/N)	Necessary Permits/Govt. Approvals Received (Y/N)	Necessary Permits/Govt. Approvals Filed (Y/N)	If Filed, Expected Date for Permits/Govt. Approval	If not Filed, Expected File Date	IC Agreement Signed (Y/N)	IC Application Deemed Complete (Y/N)	Stage in IC Process (Study/Agreement/Construction)
GASNA 36P, LLC ("San Joaquin 1B RT")	Mike Wilson	Solar Frontier Americas Development, LLC	24 Months from CPUC Approval	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD
GASNA 6P, LLC ("San Joaquin 1A")	Mike Wilson	Solar Frontier Americas Development, LLC	24 Months from CPUC Approval	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD
Bakersfield Industrial 1	Dennis Dyc-O Neal	Mirasol Development LLC	24 Months from CPUC Approval	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD
Delano Land 1	Dennis Dyc-O Neal	Mirasol Development LLC	24 Months from CPUC Approval	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD
Manteca Land 1	Dennis Dyc-O Neal	Mirasol Development LLC	24 Months from CPUC Approval	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD
Merced 1	Andrew Salinas	Green Light Energy Corp.	24 Months from CPUC Approval	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD
Tranquility 8 Amarillo	Andrew Salinas	Recurrent Energy	24 Months from CPUC Approval	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD
Java Solar Project	Paul Krebs	SunPower Corporation	24 Months from CPUC Approval	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD
54KR	Mike Wilson	Bminutenergy Renewables, LLC	24 Months from CPUC Approval	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD

Appendix B
PG&E's RAM Standard Contract

Appendix B: RAM PROGRAM: Form of Power Purchase Agreement

Standard contract terms and conditions shown in shaded text are those that “may not be modified” per CPUC Decisions (“D.”) 07-11-025; D.10-03-021, as modified by D.11-01-025; and D.13-11-024.

POWER PURCHASE AGREEMENT

Between

PACIFIC GAS AND ELECTRIC COMPANY
(as “Buyer”)

and

(as “Seller”)

POWER PURCHASE AGREEMENT

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APPENDICES

The following Appendices constitute a part of this Agreement and are incorporated into this Agreement by reference:

Appendix I	Form of Letter of Credit
Appendix II	Initial Energy Delivery Date Confirmation Letter
Appendix III	Form of Progress Report
Appendix IV	Construction Start and Commercial Operation Certification Forms and Procedures
Appendix IV-1	Construction Start Form of Certification
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Appendix IV-3	Capacity Test Procedure <i>[For Baseload Product only]</i>
Appendix V	GEP Damages Calculation
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Appendix VIII	Seller Documentation Condition Precedent
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Attachment A	Form of Actual Availability Report
Appendix X	Telemetry Parameters for Wind or Solar Facility
Appendix XI	Form of Letter of Concurrence
Appendix XII	Supplier Diversity Program
Appendix XIII	Project Specifications and Contract Capacity Calculation
Appendix XIV	Section 3.3(e) Liquidated Damages Calculation

POWER PURCHASE AGREEMENT

COVER SHEET

This Power Purchase Agreement (“Agreement”) is entered into between Pacific Gas and Electric Company, a California corporation (“Buyer” or “PG&E”), and _____ *[insert name of Seller]*, a _____ *[include place of formation and business type]* (“Seller”), as of the Execution Date. The information contained in this Cover Sheet shall be completed by Seller and incorporated into the Agreement.

A. Transaction Type

Seller may not modify the Transaction Type designated in this Part A of the Cover Sheet at any time after the Execution Date.

Program: ☐ GTSR Program

Product: ☐ As-Available Non-Peaking
☐ As-Available Peaking
☐ Baseload

Deliverability:

- ☐ Energy Only Status
- ☐ Partial Capacity Deliverability Status (“PCDS”)
- a) If PCDS is selected, provide the Expected PCDS Date, or the date the Project received a PCDS finding if already received:
_____ (mm/dd/yyyy);
- b) The Partial Capacity Deliverability Status Amount the Project will obtain is _____ MW.
- ☐ Full Capacity Deliverability Status (“FCDS”)
- a) If FCDS is selected, provide the Expected FCDS Date, or the date the Project received a FCDS finding if already received:
_____ (mm/dd/yyyy).

Seller shall elect one of the following types of transactions pursuant to Section 3.1(b) of the Agreement:

- ☐ Full Buy/Sell
- ☐ Excess Sale

Seller shall elect one of the following Delivery Terms:

- ☐ ten (10) Contract Years
- ☐ fifteen (15) Contract Years
- ☐ twenty (20) Contract Years

B. Project Description Including Description of Site

Contract Capacity: [] MW *[Provide the maximum capacity to be made available to PG&E pursuant to the transaction, which in the case of an Excess Sale transaction, may be less than the maximum capacity of the Project]*

(i) Project Development:

(a) The Project is an:

[An existing or repowered Project with substantial changes, including but not limited to, new major permits, a new interconnection study, or the construction of new generators, should check “New Project” instead of “Existing Project.”]

☐ Existing Project

☐ New Project *[GTSR Projects must be New Projects]*

(1) If the Project is a New Project:

(A) The date on which the Commercial Operation Date of the Project is expected (must be no later than the Guaranteed Commercial Operation Date):

(B) The Expected Construction Start Date of the Project:

(2) If the Project is an Existing Project:

(A) The Expected Initial Energy Delivery Date (which shall be no later than the Guaranteed Commercial Operation Date) is:

(b) Project development Milestone schedule *[to be completed by Buyer and Seller. Insert additional rows if necessary]:*

Identify Milestone	Date for Completion

(ii) Supplier Diversity. For the purpose of Section 4 of the Supplier Diversity Program obligation set forth in Appendix XII of this Agreement, Seller’s supplier diversity spend target for work supporting the Project is ____%.

C. Contract Price

The Contract Price for each MWh of Product as measured by Delivered Energy in each Contract Year and the price for Deemed Delivered Energy in each Contract Year shall be as follows:

Contract Year	Contract Price (\$/MWh)
1	
2	
3	
4	
5	
6	
7	
8	
9	
10	
11	
12	
13	
14	
15	
16	
17	
18	
19	
20	

D. Delivery Term Contract Quantity Schedule

Length of Delivery Term (in Contract Years):

Contract Year	Contract Quantity (MWh)¹
1	
2	
3	
4	
5	
6	
7	
8	
9	
10	
11	
12	
13	
14	
15	
16	
17	
18	
19	
20	

¹For a Baseload Product, the minimum qualifying Contract Quantity should be equivalent to at least an eighty percent (80%) Capacity Factor.

E. Collateral (as described in the RAM Protocol Agreement, under Section V.C. RAM PPA Terms and Conditions)

- Project Development Security (provide dollar amount)

Dollar Amount: \$ _____

- Cash, or
- Letter of Credit

- Delivery Term Security (provide dollar amount)

Dollar Amount: \$ _____

- Cash, or
- Letter of Credit

- Term Security (provide dollar amount) *[Applies to GTSR Projects 3MW or less]*

Dollar Amount: \$ _____

- Cash, or
- Letter of Credit

F. Buyer Bid Curtailment and Buyer Curtailment Orders.

Operational characteristics of the Project for Buyer Bid Curtailment and Buyer Curtailment Orders are listed below. Buyer, as the Scheduling Coordinator, may request that CAISO modify the Master File for the Project to reflect the findings of a CAISO audit of the Project. In addition, Seller agrees to coordinate with Buyer or Third-Party SC, as applicable, to ensure all information provided to the CAISO regarding the operational and technical constraints in the Master File for the Project are accurate and are based on the true physical characteristics of the resource.

- PMax of the Project: ____MW
- Minimum operating capacity: ____MW
- Ramp Rate: ____MW/Minute

[For As-Available Products]

- Advance notification required for Buyer Bid Curtailment and Buyer Curtailment Order: Not greater than the shortest Dispatch Interval in the Real-Time Market (as defined in the CAISO Tariff).
- Maximum number of Start-ups per calendar day (if any such operational limitations exist):

[For Baseload Products]

- Maximum number of Start-ups per calendar day, month, year (if any such operational limitations exist): _____
- Advance notification required for Buyer Bid Curtailment and Buyer Curtailment Order: Not greater than the shortest Dispatch Interval in the Real-Time Market (as defined in the CAISO Tariff).

Other Requirements:

- Maximum number of hours annually for Buyer Curtailment Periods: unlimited hours
- The Project will be capable of receiving and responding to all Dispatch Instruction in accordance with Section 3.1(q).
- Start-Up Time (if applicable): _____Minutes
- Minimum Run Time after Start-Up (if applicable): _____Minutes
- Minimum Down Time after Shut-Down (if applicable): _____Minutes

Note: Sellers should enter the maximum flexibility the Project can offer given the operational constraints of the technology.

G. Damage Payment (as described under Damage Payment definition in Section 1.60)

- ☐ Ten (10) year Delivery Term. Dollar amount: \$ _____
- ☐ Fifteen (15) year Delivery Term. Dollar amount: \$ _____
- ☐ Twenty (20) year Delivery Term. Dollar amount: \$ _____

H. Notices List

Name: *[Seller's Name]*, a *[include place of formation and business type]* ("Seller")

All Notices: *[Seller to complete]*

Delivery Address:

Street:

City: State: Zip:

Mail Address: (if different from above)

Attn:

Phone:

Facsimile:

Email:

DUNS:

Federal Tax ID Number:

Invoices:

Attn:

Phone:

Facsimile:

Email:

Scheduling:

Attn:

Name: Pacific Gas and Electric Company, a California corporation
("Buyer" or "PG&E")

All Notices:

Delivery Address:

77 Beale Street, Mail Code N12E
San Francisco, CA 94105-1702

Mail Address:

P.O. Box 770000, Mail Code N12E
San Francisco, CA 94177

Attn: Candice Chan (CWW9@pge.com)
Director, Contract Mgmt & Settlements

Phone: (415) 973-7780

Facsimile: (415) 972-5507

DUNS:

Federal Tax ID Number:

Invoices:

Attn: Azmat Mukhtar (ASM3@pge.com)
Manager, Electric Settlements

Phone: (415) 973-4277

Facsimile: (415) 973-2151

Scheduling:

Attn: Christopher McNeece (CMM4@pge.com)

Phone:
Facsimile:
Email:

Phone: (415) 973-4072
Facsimile: (415) 973-0400

Payments:

Attn:

Phone:
Facsimile:
Email:

Payments:

Attn: Azmat Mukhtar (ASM3@pge.com)
Manager, Electric Settlements
Phone: (415) 973-4277
Facsimile: (415) 973-2151

Wire Transfer:

BNK:
ABA:
ACCT:

Wire Transfer:

BNK:
ABA:
ACCT:

Credit and Collections:

Attn:

Phone:
Facsimile:
Email:

Credit and Collections:

Attn: Justice Awuku (J2AT@pge.com)
Manager, Credit Risk Management
Phone: (415) 973-4144
Facsimile: (415) 973-4071

With additional Notices of an Event of Default
to Contract Manager:

Attn: _____

Phone: _____

Facsimile: _____

Email: _____

Contract Manager:

Attn: Ted Yura (THY1@pge.com)
Senior Manager, Contract Management
Phone: (415) 973-8660
Facsimile: (415) 972-5507

With additional Notices of an Event of Default to:

PG&E Law Department
Attn: Renewables Portfolio Standard attorney
Phone: (415) 973-4377
Facsimile: (415) 972-5952

PREAMBLE

This Power Purchase Agreement, together with the Cover Sheet, appendices and any other attachments referenced herein, is made and entered into between PG&E and Seller, as of the Execution Date set forth in the Cover Sheet. Buyer and Seller hereby agree to the following:

GENERAL TERMS AND CONDITIONS

ARTICLE ONE: GENERAL DEFINITIONS

1.1 “Actual Availability Report” has the meaning set forth in Section 3.1(l)(i)(G). ***[For As-Available Product only]***

1.2 “Additional Extension” has the meaning set forth in Section 3.1(c)(ii).

1.3 “Affiliate” means, with respect to any person or entity, any other person or entity (other than an individual) that (a) directly or indirectly, through one or more intermediaries, controls, or is controlled by such person or entity or (b) is under common control with such person or entity. For this purpose, “control” means the direct or indirect ownership of fifty percent (50%) or more of the outstanding capital stock or other equity interests having ordinary voting power.

1.4 “Agreement” means this Power Purchase Agreement between Buyer and Seller, which is comprised of the Cover Sheet, Preamble, these General Terms and Conditions, and all appendices, schedules and any written supplements attached hereto and incorporated herein by references, as well as all written and signed amendments and modifications thereto. For purposes of Section 10.12, the word “agreement” shall have the meaning set forth in this definition. For purposes of Section 3.1(k)(viii), the word “contract” shall have the meaning set forth in this definition.

1.5 “Ancillary Services” has the meaning set forth in the CAISO Tariff.

1.6 “Arbitration” has the meaning set forth in Section 12.3.

1.7 “As-Available Non-Peaking” Product is As-Available Product with a Capacity Factor of eighty percent (80%) or less averaged over all TOD Periods and less than ninety-five percent (95%) of expected output is in the Peak and Shoulder periods, as defined in Section 4.2.

1.8 “As-Available Peaking” Product is As-Available Product with a Capacity Factor of eighty percent (80%) or less averaged over all TOD Periods and ninety-five percent (95%) or more of expected output is in the Peak and Shoulder periods, as defined in Section 4.2.

1.9 “As-Available Product” means an As-Available Non-Peaking Product or an As-Available Peaking Product that is powered by one of the following sources, except for a *de minimis* amount of Energy from other sources: (a) wind, (b) solar energy, (c) hydroelectric potential derived from small conduit water distribution facilities that do not have storage capability, or (d) other variable sources of energy that are contingent upon natural forces other than geothermal. Subject to the terms of this Agreement, (i) Seller is obligated to sell and deliver and (ii) Buyer is obligated to purchase and receive, the Energy component of As-Available Product from the Project whenever such Energy is capable of being generated from the Project. In contrast to Baseload Product, the Seller does not control the availability of fuel supply to the Project producing As-Available Product and lacks the ability to store energy and control the rate of output.

- 1.10 “Availability Workbook” has the meaning set forth in Appendix IX.
- 1.11 “Available Capacity” means the capacity from the Project, expressed in whole megawatts, that is available to generate Product. *[For As-Available Product facilities only]*
- 1.12 “Available Capacity” means the expected amount of Energy to be produced from the Project, expressed in megawatts. *[For Baseload Product facilities and small hydro facilities]*
- 1.13 “Balancing Authority” has the meaning set forth in the CAISO Tariff.
- 1.14 “Bankrupt” means with respect to any entity, such entity that (a) files a petition or otherwise commences, authorizes or acquiesces in the commencement of a proceeding or cause of action under any bankruptcy, insolvency, reorganization or similar Law, or has any such petition filed or commenced against it and such case filed against it is not dismissed in ninety (90) days, (b) makes an assignment or any general arrangement for the benefit of creditors, (c) otherwise becomes bankrupt or insolvent (however evidenced), (d) has a liquidator, administrator, receiver, trustee, conservator or similar official appointed with respect to it or any substantial portion of its property or assets, or (e) is generally unable to pay its debts as they fall due.
- 1.15 “Baseload” means a Product for which the Energy delivery levels are uniform twenty-four (24) hours per day, seven (7) days per week and has a Capacity Factor (averaged over all TOD Periods) greater than or equal to eighty percent (80%).
- 1.16 “Bid” has the meaning set forth in the CAISO Tariff.
- 1.17 “Business Day” means any day except a Saturday, Sunday, or a Federal Reserve Bank holiday and shall be between the hours of 8:00 a.m. and 5:00 p.m. local time for the relevant Party’s principal place of business where the relevant Party, in each instance unless otherwise specified, shall be the Party from whom the Notice, payment or delivery is being sent and by whom the Notice or payment or delivery is to be received.
- 1.18 “Buyer” has the meaning set forth in the Cover Sheet.
- 1.19 “Buyer Bid Curtailment” means Buyer as SC communicates a curtailment instruction to the Seller, requiring Seller to produce less Energy from the Project than the CAISO final market forecast amount to be produced from the Project for a period of time, and Buyer as the SC either (a) submitted a CAISO final market Energy Supply Bid and such curtailment is solely a result of the CAISO implementing the Energy Supply Bid; or (b) submitted a CAISO final market Self-Schedule for less than the amount of the final-market Energy forecasted to be produced from the Project. However, if the Project is subject to a Planned Outage, Forced Outage, Force Majeure and/or a Curtailment Period during the same period of time, then Buyer Bid Curtailment shall not include any Energy that is subject to such Planned Outage, Forced Outage, Force Majeure or Curtailment Period.
- 1.20 “Buyer Curtailment Order” means the instruction from Buyer to Seller to reduce generation from the Project by the amount, and for the period of time set forth in such order, for reasons unrelated to a Planned Outage, Forced Outage, Force Majeure and/or Curtailment Order.
- 1.21 “Buyer Curtailment Period” means the period of time, as measured using current Settlement Intervals, during which Seller reduces generation from the Project pursuant to (a) Buyer Bid Curtailment or (b) a Buyer Curtailment Order. The Buyer Curtailment Period shall be inclusive of the

time required for the Project to ramp down and ramp up; provided that such time periods to ramp down and ramp up shall be consistent with the Ramp Rate designated in the Cover Sheet.

1.22 “Buyer’s Notice of First Offer Acceptance” has the meaning set forth in Section 3.9(e)(ii) or Section 11.1(b)(ii), as applicable.

1.23 “Buyer’s WREGIS Account” has the meaning set forth in Section 3.1(k)(i).

1.24 “CAISO” means the California Independent System Operator Corporation or any successor entity performing similar functions.

1.25 “CAISO Global Resource ID” means the number or name assigned by the CAISO to the Project.

1.26 “CAISO Grid” has the same meaning as “CAISO Controlled Grid” as defined in the CAISO Tariff.

1.27 “CAISO Penalties” means any fees, liabilities, assessments, or similar charges assessed by the CAISO for (a) violation of the CAISO Tariff and all applicable protocols, WECC rules or CAISO operating instructions or orders or (b) as a result of a Party’s failure to follow Good Utility Practices. In either case, “CAISO Penalties” do not include the costs and charges related to scheduling and Imbalance Energy as addressed in Section 4.6(b) of this Agreement.

1.28 “CAISO Revenues” means the net amount resulting from (a) the credits and other payments received by Buyer, as Seller’s Scheduling Coordinator, as a result of test energy from the Project delivered by Seller during the Test Period, including revenues associated with CAISO dispatches and (b) the debits, costs, penalties and interest that are directly assigned by the CAISO to the CAISO Global Resource ID for the Project for, or attributable to, scheduling and deliveries from the Project under this Agreement, which amount may result in a negative or positive value.

1.29 “CAISO Tariff” means the California Independent System Operator Corporation, Fifth Replacement FERC Electric Tariff (Open Access Transmission Tariff), as it may be amended, supplemented or replaced (in whole or in part) from time to time.

1.30 “California Renewables Portfolio Standard” means the renewable energy program and policies established by California State Senate Bills 1038 and 1078 as amended by Senate Bill SB1X, and codified in California Public Utilities Code Sections 399.11 through 399.31 and California Public Resources Code Sections 25740 through 25751, as such provisions are amended or supplemented from time to time.

1.31 “Capacity Attributes” means any current or future defined characteristic (including the ability to generate at a given capacity level, provide Ancillary Services, and ramp up or ramp down at a given rate), certificate, tag, credit, flexibility, or dispatchability attribute, whether general in nature or specific as to the location or any other attribute of the Project, intended to value any aspect of the capacity of the Project to produce any and all Product, including any accounting construct so that the maximum amount of Contract Capacity of the Project may be counted toward a Resource Adequacy Requirement or any other measure by the CPUC, the CAISO, the FERC, or any other entity invested with the authority under federal or state Law, to require Buyer to procure, or to procure at Buyer’s expense, Resource Adequacy or other such products.

1.32 “Capacity Factor” has the meaning set forth in Section 4.3. ***[For Baseload Product only]***

1.33 “Capacity Test” has the meaning set forth in Appendix IV-3 attached hereto. ***[For Baseload Product only]***

1.34 “CEC” means the California Energy Commission or its successor agency.

1.35 “CEC Certification and Verification” means that the CEC has certified (or, with respect to periods before the Project has commenced commercial operation (as such term is defined by and according to the CEC), that the CEC has pre-certified) that the Project is an ERR for purposes of the California Renewables Portfolio Standard and that all Energy produced by the Project qualifies as generation from an ERR for purposes of the Project.

1.36 “Claims” means all third party claims or actions, threatened or filed and, whether groundless, false, fraudulent or otherwise, that directly or indirectly relate to the subject matter of an indemnity, and the resulting losses, damages, expenses, attorneys’ fees and court costs, whether incurred by settlement or otherwise, and whether such claims or actions are threatened or filed prior to or after the termination or expiration of this Agreement.

1.37 “Commercial Operation” means the Project is operating and able to produce and deliver the Product to Buyer pursuant to the terms of this Agreement and in the case of Baseload Product, as further provided in Appendix IV-3.

1.38 “Commercial Operation Date” means ***[For As-Available Products use the following language]***the date on which Seller (a) notifies Buyer that Commercial Operation has commenced, (b) notifies Buyer that all Reliability Network Upgrades identified in the Project’s Generator Interconnection Agreement have been completed, and (c) provides a certification of a Licensed Professional Engineer, substantially in the form attached hereto as Attachment A to Appendix IV-2, demonstrating satisfactory completion of the Commercial Operation Certification Procedure as provided in Appendix IV-2 hereto. ***[For Baseload Products use the following language]*** the date on which (a) Seller notifies Buyer that Commercial Operation has commenced, (b) Seller notifies Buyer that all Reliability Network Upgrades identified in the Project’s Generator Interconnection Agreement have been completed, (c) provides a certification of a Licensed Professional Engineer, substantially in the form attached hereto as Attachment A to Appendix IV-2, demonstrating satisfactory completion of the Commercial Operation Certification Procedure as provided in Appendix IV-2 hereto, and (d) Buyer accepts in writing the results of Seller’s initial Capacity Test report in compliance with the Capacity Test Procedure as provided in Appendix IV-3 hereto.

1.39 “Compliance Costs” means all reasonable out-of-pocket costs and expenses incurred by Seller and paid directly to third parties in connection with any of the obligations under Sections 3.1(j) (Greenhouse Gas Emissions Reporting), 3.1(k) (WREGIS), 3.1(n) (Obtaining and Maintaining CEC Certification and Verification), 3.3 (Resource Adequacy), 3.4(b) (EIRP Requirements), and 10.2(b) (ERR), including registration fees, volumetric fees, license renewal fees, external consultant fees and capital costs necessary for compliance, but excluding Seller’s internal administrative and staffing costs, due to a change, amendment, enactment or repeal of Law after the Execution Date which requires Seller to incur additional costs and expenses in connection with any of such obligations, in excess of the costs and expenses incurred for such obligations under the Law in effect as of the Execution Date. Compliance Costs do not include any amounts designated in the Project’s full capacity deliverability study to obtain FCDS nor any costs and expenses incurred by Seller for FCDS studies.

1.40 “Compliance Cost Cap” has the meaning set forth in Section 3.1(o).

1.41 “Condition Precedent” means each of, or one of, the conditions set forth in Section 2.5(a)(i) through (iv) and “Conditions Precedent” shall refer to all of the conditions set forth in Section 2.5(a)(i) through (iv).

1.42 “Confidential Information” has the meaning set forth in Section 10.7(a)

1.43 “Construction Start Date” means the later to occur of the date on which Seller delivers to Buyer (a) a copy of the Notice to Proceed that Seller has delivered to the EPC Contractor for the Project, and (b) a written Certification substantially in the form attached hereto as Appendix IV-1.

1.44 “Contract Capacity” has the meaning set forth in Section 3.1(f).

1.45 “Contract Capacity Commitment” means the amount of the Contract Capacity that may be constructed pursuant to the Governmental Approvals received or obtained by Seller as of, for a New Project, the Guaranteed Commercial Operation Date (as may be extended pursuant to Section 3.9(c)), and for an Existing Project, the Expected Initial Energy Delivery Date specified on the Cover Sheet.

1.46 “Contract Price” means the price in United States dollars (\$U.S.) (unless otherwise provided for) to be paid by Buyer to Seller for the purchase of the Product, as specified in the Cover Sheet.

1.47 “Contract Quantity” means the quantity of Delivered Energy expected to be delivered by Seller during each Contract Year as set forth in Section 3.1(e) and Cover Sheet Section D .

1.48 “Contract Year” means a period of twelve (12) consecutive months. The first Contract Year shall commence on the Initial Energy Delivery Date and each subsequent Contract Year shall commence on the anniversary of the Initial Energy Delivery Date.

1.49 “Costs” means, with respect to the Non-Defaulting Party, (a) brokerage fees, commissions and other similar third party transaction costs and expenses reasonably incurred by such Party either in terminating any arrangement pursuant to which it has hedged its obligations or in entering into new arrangements which replace the Terminated Transaction; and (b) all reasonable attorneys’ fees and expenses incurred by the Non-Defaulting Party in connection with the termination of the Transaction.

1.50 “Cover Sheet” means the cover sheet to this Agreement, completed by Seller and incorporated into the Agreement.

1.51 “CPUC” or “Commission” means the California Public Utilities Commission, or successor entity.

1.52 “CPUC Approval” means a final and non-appealable order of the CPUC, without conditions or modifications unacceptable to the Parties, or either of them, which contains the following terms:

(a) approves this Agreement in its entirety, including payments to be made by the Buyer, subject to CPUC review of the Buyer’s administration of the Agreement; and

(b) finds that any procurement pursuant to this Agreement is procurement from an eligible renewable energy resource for purposes of determining Buyer’s compliance with any obligation that it may have to procure eligible renewable energy resources pursuant to the California Renewables

Portfolio Standard (Public Utilities Code Section 399.11 *et seq.*), Decision 03-06-071, or other applicable law.

CPUC Approval will be deemed to have occurred on the date that a CPUC decision containing such findings becomes final and non-appealable.

For purposes of this section, a CPUC Energy Division disposition which contains such findings or deems approved an advice letter requesting such findings shall be deemed to satisfy the CPUC decision requirement.

1.53 “CRS” means the Center for Resource Solutions or any successor entity performing similar functions.

1.54 “Credit Rating” means, with respect to any entity, (a) the rating then assigned to such entity’s unsecured senior long-term debt obligations (not supported by third party credit enhancements) or (b) if such entity does not have a rating for its unsecured senior long-term debt obligations, then the rating assigned to such entity as an issuer rating by S&P and/or Moody’s. If the entity is rated by both S&P and Moody’s and such ratings are not equivalent, the lower of the two ratings shall determine the Credit Rating. If the entity is rated by either S&P or Moody’s, but not both, then the available rating shall determine the Credit Rating.

1.55 “Cure” has the meaning set forth in Section 8.5(b).

1.56 “Cured Performance Measurement Period” has the meaning set forth in Section 3.1(e)(ii)(C).

1.57 “Cure Payment Period” has the meaning set forth in Section 3.1(e)(ii)(C)(III).

1.58 “Curtailement Order” means any of the following:

(a) the CAISO, Reliability Coordinator, Balancing Authority or any other entity having similar authority or performing similar functions during the Delivery Term, orders, directs, alerts, or communicates via any means, to a Party to curtail Energy deliveries, which may come in the form of a request to return to Schedule consistent with the CAISO Tariff, for reasons including, (i) any System Emergency, (ii) any warning of an anticipated System Emergency, or warning of an imminent condition or situation, which jeopardizes the CAISO’s electric system integrity or the integrity of other systems to which the CAISO is connected, or (iii) any warning, forecast, or anticipated over-generation conditions, including a request from CAISO to manage over-generation conditions, provided that this subsection (a) (iii) shall not include Buyer Bid Curtailement;

(b) a curtailment ordered by the Participating Transmission Owner, distribution operator (if interconnected to distribution or sub-transmission system), or any other entity having similar authority or performing similar functions during the Delivery Term, for reasons including (i) any situation that affects normal function of the electric system including any abnormal condition that requires action to prevent circumstances such as equipment damage, loss of load, or abnormal voltage conditions, or (ii) any warning, forecast or anticipation of conditions or situations that jeopardize the Participating Transmission Owner’s electric system integrity or the integrity of other systems to which the Participating Transmission Owner is connected;

(c) scheduled or unscheduled maintenance or construction on the Participating Transmission Owner's or distribution operator's transmission or distribution facilities that prevents (i) Buyer from receiving or (ii) Seller from delivering Delivered Energy at the Delivery Point; or

(d) a curtailment in accordance with Seller's obligations under its Generator Interconnection Agreement with the Participating Transmission Owner or distribution operator.

For the avoidance of doubt, if Buyer or Third-Party SC submitted a Self-Schedule and/or an Energy Supply Bid that clears, in full, the applicable CAISO market for the full amount of Energy forecasted to be produced from the Project for any time period, any notice from the CAISO having the effect of requiring a reduction during the same time period is a Curtailment Order, not a Buyer Bid Curtailment.

1.59 "Curtailment Period" means the period of time during which Seller reduces generation from the Project, pursuant to a Curtailment Order. The Curtailment Period shall be inclusive of the time required for the Project to ramp down and ramp up; provided that such time periods to ramp down and ramp up shall be consistent with the Ramp Rate designated in the Cover Sheet.

1.60 "Damage Payment" means *[for a ten year Delivery Term the dollar amount that equals six (6) months minimum expected revenue of the Project based on Guaranteed Energy Production and the estimated average TOD-adjusted Contract Price, which will be calculated prior to the Execution Date]* *[for a fifteen year Delivery Term the dollar amount that equals nine (9) months minimum expected revenue of the Project based on Guaranteed Energy Production and the estimated average TOD-adjusted Contract Price, which will be calculated prior to the Execution Date]* *[for a twenty year or greater Delivery Term the dollar amount that equals twelve (12) months minimum expected revenue of the Project based on Guaranteed Energy Production and the estimated average TOD-adjusted Contract Price, which will be calculated prior to the Execution Date]*. *[Select bracketed language appropriate for the length of the Delivery Term]*

1.61 "DA Price" means the resource specific locational marginal price ("LMP") applied to the PNode applicable to the Project in the CAISO Day-Ahead Market.

1.62 "DA Scheduled Energy" means the Day-Ahead Scheduled Energy as defined in the CAISO Tariff.

1.63 "Day-Ahead Availability Notice" has the meaning set forth in Section 3.4[(b)][(c)][(iii)](C).

1.64 "Day-Ahead Market" has the meaning set forth in the CAISO Tariff.

1.65 "Deemed Delivered Energy" means *[For As-Available Products use the following language]* the amount of Energy expressed in MWh that the Project would have produced and delivered to the Delivery Point, but that is not produced by the Project and delivered to the Delivery Point during a Buyer Curtailment Period, which amount shall be equal to (a) the EIRP Forecast, expressed in MWh, applicable to the Buyer Curtailment Period, whether or not Seller is participating in EIRP during the Buyer Curtailment Period, less the amount of Delivered Energy delivered to the Delivery Point during the Buyer Curtailment Period or, (b) if there is no EIRP Forecast available, the result of the equation provided pursuant to Section 3.1(l)(i)(G) and using relevant Project availability, weather and other pertinent data for the period of time during the Buyer Curtailment Period less the amount of Delivered Energy delivered to the Delivery Point during the Buyer Curtailment Period; *provided that*, if the applicable difference calculated pursuant to (a) or (b) above is negative as compared to the amount of metered Energy at the

CAISO revenue meter for the Project, the Deemed Delivered Energy shall be zero (0). *[For Baseload Products use the following language]* the amount of Energy expressed in MWh that the Project would have produced and delivered to the Delivery Point, but that is not produced by the Project and delivered to the Delivery Point during a Buyer Curtailment Period, which amount shall be determined by reference to the most recent Day-Ahead Availability Notice Buyer has received from Seller at the time Buyer issues a Buyer Curtailment Order.

1.66 “Defaulting Party” means the Party that is subject to an Event of Default.

1.67 “Deficient Month” has the meaning set forth in Section 3.1(k)(v).

1.68 “Deliverability Assessment” has the meaning set forth in the CAISO Tariff.

1.69 “Deliverability Finding Deadline” shall be two (2) calendar years after the RA Start Date. The Deliverability Finding Deadline shall be no later than December 31, 2024.

1.70 “Delivered Energy” means all Energy produced from the Project as measured in MWh at the CAISO revenue meter of the Project and in accordance with the CAISO Tariff, which shall include any applicable adjustments for power factor and Electrical Losses.

1.71 “Delivery Network Upgrade” has the meaning set forth in the CAISO Tariff.

1.72 “Delivery Point” means the point at which Buyer receives Seller’s Product, as identified in Section 3.1(d).

1.73 “Delivery Term” has the meaning set forth in Section 3.1(c)(i) and shall be of the length specified in the Cover Sheet.

1.74 “Delivery Term Security” means the Performance Assurance that Seller is required to maintain, as specified in Article Eight, to secure performance of its obligations during the Delivery Term.

1.75 “Disclosing Party” has the meaning set forth in Section 10.7.

1.76 “Dispatch Instruction” has the meaning set forth in the CAISO Tariff.

1.77 “Dispatch Interval” has the meaning set forth in the CAISO Tariff.

1.78 “Distribution Loss Factor” is a multiplier factor that reduces the amount of Delivered Energy produced by a Project connecting to a distribution system to account for the electrical distribution losses, including those related to distribution and transformation, occurring between the point of interconnection, where the Participating Transmission Owner’s meter is physically located, and the first Point of Interconnection, as defined in the CAISO Tariff, with the CAISO Grid.

1.79 “Distribution Upgrades” has the meaning set forth in the CAISO Tariff.

1.80 “DUNS” means the Data Universal Numbering System, which is a unique nine character identification number provided by Dun & Bradstreet, Inc.

1.81 “Early Termination Date” has the meaning set forth in Section 5.2.

1.82 “Effective Date” means the date on which all of the Conditions Precedent set forth in Section 2.5(a) have been satisfied or waived in writing by both Parties.

1.83 “Effective FCDS Date” means the date on which Seller provides Buyer Notice and documentation from CAISO that the Project has attained Full Capacity Deliverability Status, which Buyer subsequently finds, in its reasonable discretion, to be adequate evidence that the Project has attained Full Capacity Deliverability Status.

1.84 “Effective PCDS Date” means the date on which Seller provides Buyer Notice and documentation from CAISO that the Project has attained Partial Capacity Deliverability Status, which Buyer subsequently finds, in its reasonable discretion, to be adequate evidence that the Project has attained Partial Capacity Deliverability Status.

1.85 “EIRP Forecast” means the final forecast of the Energy to be produced by the Project prepared by the CAISO in accordance with the Eligible Intermittent Resources Protocol and communicated to Buyer or Third-Party SC for use in submitting a Schedule for the output of the Project in the Real-Time Market.

1.86 “Electrical Losses” means all applicable losses, including the following: (a) any transmission or transformation losses between the CAISO revenue meter(s) and the Delivery Point; and (b) the Distribution Loss Factor, if applicable.

1.87 “Electric System Upgrades” means any Network Upgrades, Distribution Upgrades, or Interconnection Facilities that are determined to be necessary by the CAISO or Participating Transmission Owner, as applicable, to physically and electrically interconnect the Project to the Participating Transmission Owner’s electric system for receipt of Energy at the Point of Interconnection (as defined in the CAISO Tariff) if connecting to the CAISO Grid, or the Interconnection Point, if connecting to a part of the Participating TO’s electric system that is not part of the CAISO Grid.

1.88 “Electrician” means any person responsible for placing, installing, erecting, or connecting any electrical wires, fixtures, appliances, apparatus, raceways, conduits, solar photovoltaic cells or any part thereof, which generate, transmit, transform or utilize energy in any form or for any purpose.

1.89 “Eligible Intermittent Resources Protocol” or “EIRP” means the Eligible Intermittent Resource Protocol, as may be amended from time to time, as set forth in the CAISO Tariff.

1.90 “Eligible LC Bank” means either a U.S. commercial bank, or a foreign bank issuing a Letter of Credit through its U.S. branch; and in each case the issuing U.S. commercial bank or foreign bank must be acceptable to Buyer in its sole discretion and such bank must have a Credit Rating of at least: (a) “A-, with a stable designation” from S&P and “A3, with a stable designation” from Moody’s, if such bank is rated by both S&P and Moody’s; or (b) “A-, with a stable designation” from S&P or “A3, with a stable designation” from Moody’s, if such bank is rated by either S&P or Moody’s, but not both, even if such bank was rated by both S&P and Moody’s as of the date of issuance of the Letter of Credit but ceases to be rated by either, but not both of those ratings agencies.

1.91 “Eligible Renewable Energy Resource” or “ERR” has the meaning set forth in California Public Utilities Code Section 399.12 and California Public Resources Code Section 25741, as either code provision is amended or supplemented from time to time.

1.92 “Energy” means three-phase, 60-cycle alternating current electric energy measured in MWh and net of auxiliary loads and station electrical uses (unless otherwise specified).

1.93 “Energy Deviation(s)” means the absolute value of the difference, in MWh, in any Settlement Interval between (a) the final accepted Bid submitted for the Project; and (b) Delivered Energy.

1.94 “Energy Only Status Seller” or “EOS Seller” means a Seller that has selected Energy Only Status in the Cover Sheet. For avoidance of doubt, an EOS Seller does not have an obligation to have or obtain a Full Capacity Deliverability Status Finding.

1.95 “Energy Supply Bid” has the meaning set forth in the CAISO Tariff.

1.96 “EPC Contract” means the Seller’s engineering, procurement and construction contract with the EPC Contractor.

1.97 “EPC Contractor” means an engineering, procurement, and construction contractor, or if not utilizing an engineering, procurement and construction contractor, the entity having lead responsibility for the management of overall construction activities, selected by Seller, with substantial experience in the engineering, procurement, and construction of power plants of the same type of facility as the Seller’s; provided, however, that the Seller or the Seller’s Affiliate(s) may serve as the EPC Contractor.

1.98 “Equitable Defenses” means any bankruptcy, insolvency, reorganization or other Laws affecting creditors’ rights generally and, with regard to equitable remedies, the discretion of the court before which proceedings may be pending to obtain same.

1.99 “Event of Default” has the meaning set forth in Section 5.1.

1.100 “Excess Deemed Delivered Energy” has the meaning set forth in Section 4.5(a)(i). ***[For As-Available Product only]***

1.101 “Excess Deemed Delivered Energy Price” has the meaning set forth in Section 4.5(a)(ii)(B). ***[For As-Available Product only]***

1.102 “Excess Delivered Energy” has the meaning set forth in Section 4.5(a)(i). ***[For As-Available Product only]***

1.103 “Excess Delivered Energy Price” has the meaning set forth in Section 4.5(a)(ii)(A). ***[For As-Available Product only]***

1.104 “Excess Energy” has the meaning set forth in Section 4.5(a)(i). ***[For As-Available Product only]***

1.105 “Excess Network Upgrade Costs” has the meaning set forth in Section 3.9(f)(ii).

1.106 “Excess Sale” means the type of transaction described in Section 3.1(b)(ii).

1.107 “Exclusivity Period” has the meaning set forth in Section 3.9(e)(i) or Section 11.1(b)(i), as applicable.

1.108 “Execution Date” means the latest signature date found on the signature page of this Agreement.

1.109 “Executive(s)” has the meaning set forth in Section 12.2(a).

1.110 “Exempt Wholesale Generator” has the meaning provided in 18 C.F.R. Section 366.1.

1.111 “Existing Project” is a Project that has achieved Commercial Operation on or prior to the Execution Date.

1.112 “Expected Construction Start Date” has the meaning set forth in the Cover Sheet.

1.113 “Expected FCDS Date” means the date set forth in Section A of the Cover Sheet which is the date the Project is expected to achieve Full Capacity Deliverability Status.

1.114 “Expected PCDS Date” means the date set forth in Section A of the Cover Sheet which is the date the Project is expected to achieve Partial Capacity Deliverability Status.

1.115 “Expected Initial Energy Delivery Date” is the date specified on the Cover Sheet for an Existing Project.

1.116 “Expected Net Qualifying Capacity” means an estimate of the amount of Net Qualifying Capacity the Project would have received had it obtained deliverability according to the deliverability type selected in Section A of the Cover Sheet, as determined in accordance with Appendix XIV.

1.117 “FERC” means the Federal Energy Regulatory Commission or any successor government agency.

1.118 “Final True-Up” means the final payment made pursuant to this Agreement settling all invoices by the Party with an outstanding net amount due to the other Party for Product delivered prior to the end of the Delivery Term or other amounts due pursuant to this Agreement incurred prior to the end of the Delivery Term.

1.119 “First Offer” has the meaning set forth in Section 3.9(e)(1) or Section 11.1(b)(i), as applicable.

1.120 “Force Majeure” means any event or circumstance which wholly or partly prevents or delays the performance of any material obligation arising under this Agreement, but only if and to the extent (i) such event is not within the reasonable control, directly or indirectly, of the Party seeking to have its performance obligation(s) excused thereby, (ii) the Party seeking to have its performance obligation(s) excused thereby has taken all reasonable precautions and measures in order to prevent or avoid such event or mitigate the effect of such event on such Party’s ability to perform its obligations under this Agreement and which by the exercise of due diligence such Party could not reasonably have been expected to avoid and which by the exercise of due diligence it has been unable to overcome, and (iii) such event is not the direct or indirect result of the negligence or the failure of, or caused by, the Party seeking to have its performance obligations excused thereby.

(a) Subject to the foregoing, events that could qualify as Force Majeure include the following:

(i) flooding, lightning, landslide, earthquake, fire, drought, explosion, epidemic, quarantine, storm, hurricane, tornado, volcanic eruption, other natural disaster or unusual or extreme adverse weather-related events;

(ii) war (declared or undeclared), riot or similar civil disturbance, acts of the public enemy (including acts of terrorism), sabotage, blockade, insurrection, revolution, expropriation or confiscation;

(iii) except as set forth in subsection (b)(viii) below, strikes, work stoppage or other labor disputes (in which case the affected Party shall have no obligation to settle the strike or labor dispute on terms it deems unreasonable); or

(iv) emergencies declared by the Transmission Provider or any other authorized successor or regional transmission organization or any state or federal regulator or legislature requiring a forced curtailment of the Project or making it impossible for the Transmission Provider to transmit Energy, including Energy to be delivered pursuant to this Agreement; provided that, if a curtailment of the Project pursuant to this subsection (a)(iv) would also meet the definition of a Curtailment Period, then it shall be treated as a Curtailment Period for purposes of Section 3.1(p).

(b) Force Majeure shall not be based on:

(i) Buyer's inability economically to use or resell the Product purchased hereunder;

(ii) Seller's ability to sell the Product at a price greater than the price set forth in this Agreement;

(iii) Seller's inability to obtain permits or approvals of any type for the construction, operation, or maintenance of the Project, including a delay that could constitute a Permitting Delay unless caused solely by an event of Force Majeure of the specific type described in any of subsections (a)(i) through (a)(iv) above;

(iv) Seller's inability to complete interconnection or Electric System Upgrades by the Guaranteed Commercial Operation Date, including a delay that could constitute a Transmission Delay, unless such delay is caused solely by an event of Force Majeure of the specific type described in any of subsections (a)(i) through (a)(iv) above;

(v) Seller's inability to obtain sufficient fuel, power or materials to operate the Project, except if Seller's inability to obtain sufficient fuel, power or materials is caused solely by an event of Force Majeure of the specific type described in any of subsections (a)(i) through (a)(iv) above;

(vi) Seller's failure to obtain additional funds, including funds authorized by a state or the federal government or agencies thereof, to supplement the payments made by Buyer pursuant to this Agreement;

(vii) a Forced Outage except where such Forced Outage is caused by an event of Force Majeure of the specific type described in any of subsections (a)(i) through (a)(iv) above;

(viii) a strike, work stoppage or labor dispute limited only to any one or more of Seller, Seller's Affiliates, the EPC Contractor or subcontractors thereof or any other third party employed by Seller to work on the Project;

(ix) any equipment failure except if such equipment failure is caused solely by an event of Force Majeure of the specific type described in any of subsections (a)(i) through (a)(iv) above; or

(x) a Party's inability to pay amounts due to the other Party under this Agreement, except if such inability is caused solely by a Force Majeure event that disables physical or electronic facilities necessary to transfer funds to the payee Party.

1.121 "Force Majeure Extension" has the meaning set forth in Section 3.9(c)(ii)(C).

1.122 "Force Majeure Failure" has the meaning set forth in Section 11.1(a).

1.123 "Forced Outage" means any unplanned reduction or suspension of the electrical output from the Project or unavailability of the Product in whole or in part from a Unit in response to any control system trip or operator-initiated trip in response to an alarm or equipment malfunction; or any other unavailability of the Project or a Unit for operation, in whole or in part, for maintenance or repair that is not a Planned Outage and not the result of Force Majeure.

1.124 "Forecasting Penalty" has the meaning set forth in Section 4.6(c)(iii), and "Forecasting Penalties" means more than one Forecasting Penalty. ***[For As-Available Product only]***

1.125 "Full Buy/Sell" is the type of transaction described in Section 3.1(b)(i).

1.126 "Full Capacity Deliverability Status" or "FCDS" has the meaning set forth in the CAISO Tariff except that it applies to any Generating Facility (as defined in the CAISO Tariff).

1.127 "Full Capacity Deliverability Status Finding" or "FCDS Finding" means a written confirmation from the CAISO that the Project is eligible for FCDS.

1.128 "Full Capacity Deliverability Status Seller" or "FCDS Seller" means a Seller that selected Full Capacity Deliverability Status in the Cover Sheet and either has previously obtained, or is obligated to obtain per the terms of the Agreement, a Full Capacity Deliverability Status Finding.

1.129 "Gains" means with respect to any Party, an amount equal to the present value of the economic benefit to it, if any (exclusive of Costs), resulting from the termination of the Transaction, determined in a commercially reasonable manner, subject to Section 5.3 hereof. Factors used in determining economic benefit may include reference to information either available to it internally or supplied by one or more third parties, including quotations (either firm or indicative) of relevant rates, prices, yields, yield curves, volatilities, spreads or other relevant market data in the relevant markets, market price referent, market prices for a comparable transaction, forward price curves based on economic analysis of the relevant markets, settlement prices for a comparable transaction at liquid trading platforms (e.g., NYMEX), all of which should be calculated for the remaining Delivery Term to determine the value of the Product.

1.130 "Generally Accepted Accounting Principles" means the standards for accounting and preparation of financial statements established by the Federal Accounting Standards Advisory Board (or its successor agency) or any successor standards adopted pursuant to relevant SEC rule.

1.131 "Generator Interconnection Agreement" or "GIA" means, for Projects interconnecting at the transmission level, the agreement and associated documents (or any successor agreement and associated documentation approved by FERC) by and among Seller, the Participating Transmission Owner, and the CAISO governing the terms and conditions of Seller's interconnection with the CAISO Grid, including any description of the plan for interconnecting to the CAISO Grid. For Projects interconnecting at the distribution level, it means the agreement and associated documents (or any successor agreement and associated documentation) by and between Seller and the Participating

Transmission Owner governing the terms and conditions of Seller's interconnection with the Participating TO's distribution system, including any description of the plan for interconnecting to Participating TO's distribution system.

1.132 "Generator Interconnection Process" or "GIP" means the Generator Interconnection Procedures set forth in the CAISO Tariff or Participating TO's tariff, as applicable, and associated documents; provided that if the GIP is replaced by such other successor procedures governing interconnection (a) to the CAISO Grid or Participating TO's distribution system, as applicable, or (b) of generating facilities with an expected net capacity equal to or greater than the Project's Contract Capacity, the term "GIP" shall then apply to such successor procedure.

1.133 "Geothermal Reservoir Report" means a report obtained by Seller from an expert independent consulting firm qualified in geothermal reservoir assessment which assesses the geothermal potential at the Site. *[For Geothermal Projects only]*

1.134 "GEP Cure" has the meaning set forth in Section 3.1(e)(ii)(C).

1.135 "GEP Damages" has the meaning set forth in Appendix V.

1.136 "GEP Failure" means Seller's failure to produce Delivered Energy plus Deemed Delivered Energy in an amount equal to or greater than the Guaranteed Energy Production amount for the applicable Performance Measurement Period.

1.137 "GEP Shortfall" means the amount in MWh by which Seller failed to achieve the Guaranteed Energy Production in the applicable Performance Measurement Period.

1.138 "Good Utility Practice" has the meaning provided in the CAISO Tariff.

1.139 "Governmental Approval" means all authorizations, consents, approvals, waivers, exceptions, variances, filings, permits, orders, licenses, exemptions and declarations of or with any governmental entity and shall include those siting and operating permits and licenses, and any of the foregoing under any applicable environmental Law, that are required for the construction, use and operation of the Project.

1.140 "Governmental Authority" means any federal, state, local or municipal government, governmental department, commission, board, bureau, agency, or instrumentality, or any judicial, regulatory or administrative body, having jurisdiction as to the matter in question.

1.141 "Governmental Charges" has the meaning set forth in Section 9.2.

1.142 "Green Attributes" means any and all credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, attributable to the generation from the Project, and its avoided emission of pollutants. Green Attributes include but are not limited to Renewable Energy Credits, as well as: (a) any avoided emission of pollutants to the air, soil or water such as sulfur oxides (SO_x), nitrogen oxides (NO_x), carbon monoxide (CO) and other pollutants; (b) any avoided emissions of carbon dioxide (CO₂), methane (CH₄), nitrous oxide, hydrofluorocarbons, perfluorocarbons, sulfur hexafluoride and other greenhouse gases (GHGs) that have been determined by the United Nations Intergovernmental Panel on Climate Change, or otherwise by Law, to contribute to the actual or potential threat of altering the Earth's

climate by trapping heat in the atmosphere;¹ (c) the reporting rights to these avoided emissions, such as Green Tag Reporting Rights. Green Tag Reporting Rights are the right of a Green Tag Purchaser to report the ownership of accumulated Green Tags in compliance with federal or state Law, if applicable, and to a federal or state agency or any other party at the Green Tag Purchaser's discretion, and include without limitation those Green Tag Reporting Rights accruing under Section 1605(b) of The Energy Policy Act of 1992 and any present or future federal, state, or local Law, regulation or bill, and international or foreign emissions trading program. Green Tags are accumulated on a MWh basis and one Green Tag represents the Green Attributes associated with one (1) MWh of Energy. Green Attributes do not include (i) any Energy, capacity, reliability or other power attributes from the Project, (ii) production tax credits associated with the construction or operation of the Project and other financial incentives in the form of credits, reductions, or allowances associated with the Project that are applicable to a state or federal income taxation obligation, (iii) fuel-related subsidies or "tipping fees" that may be paid to Seller to accept certain fuels, or local subsidies received by the generator for the destruction of particular preexisting pollutants or the promotion of local environmental benefits, or (iv) emission reduction credits encumbered or used by the Project for compliance with local, state, or federal operating and/or air quality permits. If the Project is a biomass or biogas facility and Seller receives any tradable Green Attributes based on the greenhouse gas reduction benefits or other emission offsets attributed to its fuel usage, it shall provide Buyer with sufficient Green Attributes to ensure that there are zero net emissions associated with the production of electricity from the Project.

1.143 "Green-e® Energy Certification" means the independent certification and verification program for renewable energy and greenhouse gas emission reductions as administered by CRS.

1.144 "GTSR Program" means the Green Tariff Shared Renewables program implemented per Senate Bill (SB) 43 (Stats. 2013, ch. 413 (Wolk)) and CPUC Decision 15-01-051.

1.145 "GTSR Project" means a Project procured for the GTSR Program in accordance with Green-e® Energy Certification.

1.146 "Guaranteed Commercial Operation Date" has the meaning set forth in Section 3.9(c)(i).

1.147 "Guaranteed Energy Production" or "GEP" has the meaning set forth in Section 3.1(e)(ii).

1.148 "Guaranty" means a guaranty issued by an entity and in a form acceptable to Buyer in Buyer's sole discretion.

1.149 "Imbalance Energy" has the meaning set forth in the CAISO Tariff.

1.150 "Initial Energy Delivery Date" has the meaning set forth in Section 3.1(c)(i).

1.151 "Initial Extension" has the meaning set forth in Section 3.1(c)(ii).

1.152 "Initial Negotiation End Date" has the meaning set forth in Section 12.2(a).

¹ Avoided emissions may or may not have any value for GHG compliance purposes. Although avoided emissions are included in the list of Green Attributes, this inclusion does not create any right to use those avoided emissions to comply with any GHG regulatory program.

1.153 “Interconnection Customer’s Interconnection Facilities” has the meaning set forth in the CAISO Tariff or Participating TO’s tariff, as applicable.

1.154 “Interconnection Facilities” has the meaning set forth in the CAISO Tariff.

1.155 “Interconnection Point” means the physical interconnection point of the Project as identified by Seller in the Cover Sheet.

1.156 “Interconnection Study” means any of the studies defined in the CAISO Tariff or, if applicable, any distribution provider’s tariff that reflect the methodology and costs to interconnect the Project to the Participating Transmission Owner’s electric grid.

1.157 “Integrated Forward Market” has the meaning set forth in the CAISO Tariff.

1.158 “Interest Amount” means, with respect to an Interest Period, the amount of interest calculated as follows: (a) the sum of (i) the principal amount of Performance Assurance in the form of cash held by Buyer during that Interest Period, and (ii) the sum of all accrued and unpaid Interest Amounts accumulated prior to such Interest Period; (b) multiplied by the Interest Rate in effect for that Interest Period; (c) multiplied by the number of days in that Interest Period; (d) divided by 360.

1.159 “Interest Payment Date” means the date of returning unused Performance Assurance held in the form of cash.

1.160 “Interest Period” means the monthly period beginning on the first day of each month and ending on the last day of each month.

1.161 “Interest Rate” means the rate per annum equal to the “Monthly” Federal Funds Rate (as reset on a monthly basis based on the latest month for which such rate is available) as reported in Federal Reserve Bank Publication H.15(519), or its successor publication.

1.162 “JAMS” means JAMS, Inc. or its successor entity, a judicial arbitration and mediation service.

1.163 “Law” means any statute, law, treaty, rule, regulation, CEC guidance document, ordinance, code, permit, enactment, injunction, order, writ, decision, authorization, judgment, decree or other legal or regulatory determination or restriction by a court or Governmental Authority of competent jurisdiction, including any of the foregoing that are enacted, amended, or issued after the Execution Date, and which becomes effective after the Execution Date; or any binding interpretation of the foregoing. For purposes of Sections 1.52 “CPUC Approval,” 10.2(b), “Seller Representations and Warranties” and 10.12 “Governing Law”, the term “law” shall have the meaning set forth in this definition.

1.164 “Letter of Credit” means an irrevocable, non-transferable standby letter of credit, the form of which must be substantially as contained in Appendix I to this Agreement; provided, that, if the issuer is a U.S. branch of a foreign commercial bank, Buyer may require changes to such form; the issuer must be an Eligible LC Bank on the date of Transfer; and the issuing Letter of Credit amount may not be greater than the Maximum Issuing Amount if the total amount of collateral posted by the Seller in the form of Letter of Credit exceeds ten million dollars (\$10,000,000.00) on the date of Transfer.

1.165 “Licensed Professional Engineer” means a person acceptable to Buyer in its reasonable judgment who (a) is licensed to practice engineering in California, (b) has training and experience in the power industry specific to the technology of the Project, (c) has no economic relationship, association, or

nexus with Seller or Buyer, other than to meet the obligations of Seller pursuant to this Agreement, (d) is not a representative of a consultant, engineer, contractor, designer or other individual involved in the development of the Project or of a manufacturer or supplier of any equipment installed at the Project, and (e) is licensed in an appropriate engineering discipline for the required certification being made.

1.166 “Losses” means, with respect to any Party, an amount equal to the present value of the economic loss to it, if any (exclusive of Costs), resulting from the termination of the Transaction, determined in a commercially reasonable manner, subject to Section 5.3 hereof. Factors used in determining the loss of economic benefit may include reference to information either available to it internally or supplied by one or more third parties including quotations (either firm or indicative) of relevant rates, prices, yields, yield curves, volatilities, spreads or other relevant market data in the relevant markets, market price referent, market prices for a comparable transaction, forward price curves based on economic analysis of the relevant markets, settlement prices for a comparable transaction at liquid trading platforms (e.g. NYMEX), all of which should be calculated for the remaining term of the Transaction to determine the value of the Product.

1.167 “Manager” has the meaning set forth in Section 12.2(a).

1.168 “Master File” has the meaning set forth in the CAISO Tariff.

1.169 “Maximum Issuing Amount” means the amount of a Letter of Credit to be issued by an Eligible LC Bank, which cannot exceed the lesser of (a) sixty percent (60%) of the total collateral posted by Seller in the form of Letter of Credit including the Letter of Credit to be issued or (b) twenty-five million dollars (\$25,000,000.00), without Buyer’s prior written consent.

1.170 “Milestone(s)” means the key development activities required for the construction and operation of the Project, as set forth in Section B(i)(b) of the Cover Sheet.

1.171 “Minimum Load” has the meaning set forth in the CAISO Tariff.

1.172 “Minimum Down Time” has the meaning set forth in the CAISO Tariff.

1.173 “Monthly Payment for Excess Energy” has the meaning set forth in Section 4.5(b). ***[For As-Available Product only]***

1.174 “Monthly Period” has the meaning set forth in Section 4.2.

1.175 “Monthly TOD Payment” has the meaning set forth in Section 4.4.

1.176 “Moody’s” means Moody’s Investors Service, Inc., or its successor.

1.177 “MW” means megawatt in alternating current or AC.

1.178 “MWh” means megawatt-hour.

1.179 “NERC” means the North American Electric Reliability Corporation or a successor organization that is responsible for establishing reliability criteria and protocols.

1.180 “Net Rated Output Capacity” means the Project’s Energy production capability as measured at the CAISO revenue meter in any Capacity Test inclusive of deductions for all applicable Electrical Losses. ***[Applies to Baseload Product only]***

- 1.181 “Net Qualifying Capacity” has the meaning set forth in the CAISO Tariff.
- 1.182 “Network Upgrades” has the meaning set forth in the CAISO Tariff or the Participating TO’s tariff, as applicable.
- 1.183 “New Project” is a Project that has not achieved Commercial Operation on or prior to the Execution Date.
- 1.184 “NOAA” means National Oceanic and Atmospheric Administration or successor thereto.
- 1.185 “Non-Defaulting Party” has the meaning set forth in Section 5.2.
- 1.186 “Notice,” unless otherwise specified in the Agreement, means written communications by a Party to be delivered by hand delivery, United States mail, overnight courier service, facsimile or electronic messaging (e-mail). The Cover Sheet contains the names and addresses to be used for Notices.
- 1.187 “Notice to Proceed” means the full notice to proceed, provided by Seller to the EPC Contractor following execution of the EPC Contract between Seller and such EPC Contractor and satisfaction of all conditions to performance of such contract, by which Seller authorizes such EPC Contractor to begin mobilization and construction of the Project without any delay or waiting periods.
- 1.188 “Operational Deliverability Assessment” has the meaning set forth in the CAISO Tariff.
- 1.189 “Outage Notification Procedures” means the procedures specified in Appendix VI, attached hereto. PG&E reserves the right to revise or change the procedures upon written Notice to Seller.
- 1.190 “Partial Capacity Deliverability Status” or “PCDS” has the meaning set forth in the CAISO Tariff.
- 1.191 “Partial Capacity Deliverability Status Amount” means the number of MW that the Project will obtain, as stated in the Deliverability type selected in Section A of the Cover Sheet.
- 1.192 “Partial Capacity Deliverability Status Finding” or “PCDS Finding” means a written confirmation from the CAISO that the Project is eligible for PCDS.
- 1.193 “Participating Intermittent Resource” or “PIRP” has the meaning set forth in the CAISO Tariff. ***[For As-Available Product only]***
- 1.194 “Participating Transmission Owner” or “Participating TO” means an entity that (a) owns, operates and maintains transmission lines and associated facilities and/or has entitlements to use certain transmission lines and associated facilities and (b) has transferred to the CAISO operational control of such facilities and/or entitlements to be made part of the CAISO Grid.
- 1.195 “Party” means the Buyer or Seller individually, and “Parties” means both collectively. For purposes of Section 10.12, Governing Law, the word “party” or “parties” shall have the meaning set forth in this definition.
- 1.196 “Performance Assurance” means collateral provided by Seller to Buyer to secure Seller’s obligations hereunder and includes Project Development Security, Delivery Term Security, and Term Security, as applicable. Acceptable forms of collateral are cash or a Letter of Credit as designated in

Section E of the Cover Sheet. The required form of Letter of Credit is attached hereto in Appendix I. ***[Existing ERRs to replace Project Development Security with Pre-Delivery Term Security]***

1.197 “Performance Measurement Period” has the meaning set forth in Section 3.1(e)(ii).

1.198 “Performance Tolerance Band” shall be calculated as set forth in Section 4.5(c)(ii).

1.199 “Permit Failure” has the meaning set forth in Section 3.9(d). ***[For New Projects only]***

1.200 “Permitting Delay” has the meaning set forth in Section 3.9(c)(ii)(A).

1.201 “Permitted Extensions” means extensions to the Guaranteed Commercial Operation Date due to Permitting Delay, Transmission Delay, or Force Majeure Extension, as applicable, pursuant to Section 3.9(c).

1.202 “Planned Outage” means the removal of equipment from service availability for inspection and/or general overhaul of one or more major equipment groups. To qualify as a Planned Outage, the maintenance (a) must actually be conducted during the Planned Outage, and in Seller’s sole discretion must be of the type that is necessary to reliably maintain the Project, (b) cannot be reasonably conducted during Project operations, and (c) causes the generation level of the Project to be reduced by at least ten percent (10%) of the Contract Capacity.

1.203 “PMax” has the meaning set forth in the CAISO Tariff.

1.204 “PNode” has the meaning set forth in the CAISO Tariff.

1.205 “Preamble” means the paragraph that precedes Article One: General Definitions to this Agreement.

1.206 “Preschedule Day” has the meaning set forth in Section 3.4[(b)][(c)](iii).

1.207 “Product” means the Energy, capacity, Ancillary Services, and all products, services and/or attributes similar to the foregoing which are or can be produced by or associated with the Project, including renewable attributes, Renewable Energy Credits, Capacity Attributes and Green Attributes.

1.208 “Production Tax Credit” or “PTC” means the tax credit for electricity produced from certain renewable generation resources described in Section 45 of the Internal Revenue Code of 1986, as it may be amended or supplemented from time to time.

1.209 “Progress Report” means the report similar in form and content to that attached hereto as Appendix III.

1.210 “Project” means all of the Unit(s) and the Site at which the generating facility is located and the other assets, tangible and intangible, that compose the generation facility, including the assets used to connect the Unit(s) to the Interconnection Point, as more particularly described in the Cover Sheet.

1.211 “Project Development Security” is the collateral required of Seller, as specified and referred to in Section 8.4(a). ***[Existing ERRs to replace Project Development Security with Pre-Delivery Term Security]***

1.212 “Project Specifications” has the meaning set forth in Appendix XIII.

1.213 “Prolonged Outage” is any period of more than thirty (30) consecutive days during which the Project is or will be unable, for whatever reason, to provide at least sixty percent (60%) of the Contract Capacity.

1.214 “Qualifying Facility” has the meaning provided in the Public Utility Regulatory Policies Act (“PURPA”) and in regulations of the FERC at 18 C.F.R. §§ 292.201 through 292.207.

1.215 “RA Deficiency Amount” means the liquidated damages payment that Seller shall pay to Buyer for an applicable RA Shortfall Month as calculated in accordance with Section 3.3(e)(ii).

1.216 “RA Shortfall Period” means the period of consecutive calendar months that starts with the calendar month in which the RA Start Date occurs and concludes with the second calendar month following the calendar month in which the Effective FCDS Date or Effective PCDS Date occurs. The RA Shortfall Period shall not exceed twenty-six (26) months.

1.217 “RA Shortfall Month” means the applicable calendar month within the RA Shortfall Period for purposes of calculating an RA Deficiency Amount under Section 3.3(e)(ii).

1.218 “RA Start Date” shall be the later of the Initial Energy Delivery Date or the Expected PCDS Date or FCDS Date according to the deliverability type selected in Section A of the Cover Sheet.

1.219 “RA Value” means the value in U.S. dollars per MW of Expected Net Qualifying Capacity for each RA Shortfall Month, as set forth in Appendix XIV.

1.220 “Ramp Rate” has the meaning set forth in the CAISO Tariff.

1.221 “Real-Time Market” means any existing or future intra-day market conducted by the CAISO occurring after the Day-Ahead Market.

1.222 “Real-Time Price” means the Resource-Specific Settlement Interval LMP as defined in the CAISO Tariff. If there is more than one applicable Real-Time Price for the same period of time, Real-Time Price shall mean the price associated with the smallest time interval.

1.223 “Reductions” has the meaning set forth in Section 4.7(b).

1.224 “Referral Date” has the meaning set forth in Section 12.2(a).

1.225 “Reliability Coordinator” has the meaning set forth in the CAISO Tariff.

1.226 “Reliability Must-Run Contract” has the meaning set forth in the CAISO Tariff. ***[For Baseload Product only]***

1.227 “Reliability Network Upgrade” has the meaning set forth in the CAISO Tariff.

1.228 “Renewable Energy Credit” has the meaning set forth in California Public Utilities Code Section 399.12(h) and CPUC Decision 08-08-028, as may be amended from time to time or as further defined or supplemented by Law.

1.229 “Replacement Capacity Rules” means the replacement requirement for Resource Adequacy Capacity (as defined in the CAISO Tariff) associated with a Planned Outage as set forth in the CAISO Tariff or successor replacement requirements as prescribed by the CPUC, CAISO and/or other regional entity.

1.230 “Resource Adequacy” means the procurement obligation of load serving entities, including Buyer, as such obligations are described in CPUC Decisions D.04-01-050, 04-10-035 and 05-10-042, 06-04-040, 06-06-064, 06-07-031, 07-06-029, 08-06-031, 09-06-028, 10-06-036, 11-06-022, 12-06-025, 13-06-024, and any other existing or subsequent decisions, resolutions or rulings addressing Resource Adequacy issues, as those obligations may be altered from time to time in the CPUC Resource Adequacy Rulemakings (R.) 04-04-003 and (R.) 05-12-013 or by any successor proceeding, and all other Resource Adequacy obligations established by any other entity, including the CAISO.

1.231 “Resource Adequacy Plan” has the meaning set forth in the CAISO Tariff.

1.232 “Resource Adequacy Requirements” has the meaning set forth in Section 3.3.

1.233 “Resource Adequacy Standards” means (a) the Program set forth in Section 40.9 of the CAISO Tariff and (b) any future program or provision under the CAISO Tariff providing for availability standards or similar standards with respect to any flexible Resource Adequacy resource, product, or procurement obligation; in the case of (a) or (b), as any such program or provision may be amended, supplemented, or replaced (in whole or in part) from time to time, setting forth certain standards regarding the desired level of availability for Resource Adequacy resources and possible changes and incentive payments for performance thereunder.

1.234 “Resource-Specific Settlement Interval LMP” has the meaning set forth in the CAISO Tariff.

1.235 “Retained Revenues” has the meaning set forth in Section 4.7(c).

1.236 “Revised Offer” has the meaning set forth in Section 3.9(e)(iii) or Section 11.1(b)(iii), as applicable.

1.237 “S&P” means the Standard & Poor’s Financial Services, LLC (a subsidiary of The McGraw-Hill Companies, Inc.) or its successor.

1.238 “Satisfaction Date” has the meaning set forth in Section 2.6.

1.239 “Schedule” has the meaning set forth in the CAISO Tariff.

1.240 “Scheduling Coordinator” or “SC” means an entity certified by the CAISO as qualifying as a Scheduling Coordinator pursuant to the CAISO Tariff, for the purposes of undertaking the functions specified in “Responsibilities of a Scheduling Coordinator” of the CAISO Tariff, as amended from time to time.

1.241 “SEC” means the U.S. Securities and Exchange Commission.

1.242 “Self-Schedule” has the meaning set forth in the CAISO Tariff.

1.243 “Seller” has the meaning set forth in the Cover Sheet.

1.244 “Seller Excuse Hours” means those hours during which Seller is unable to deliver Delivered Energy to Buyer as a result of (a) a Force Majeure event, (b) Buyer’s failure to perform, or (c) Curtailment Period.

1.245 “Seller’s WREGIS Account” has the meaning set forth in Section 3.1(k)(i).

1.246 “Settlement Amount” means the amount in US dollars equal to the sum of Losses, Gains, and Costs, which the Non-Defaulting Party incurs as a result of the termination of this Agreement.

1.247 “Settlement Interval” has the meaning set forth in the CAISO Tariff.

1.248 “Settlement Interval Actual Available Capacity” means the sum of the capacity, in MWs, of all generating units of the Project that were available as of the end of such Settlement Interval, as indicated by the Actual Availability Report. *[For As-Available Product only]*

1.249 “Shared Contract Year” has the meaning set forth in section 3.1(e)(ii)(C)(I).

1.250 “Site” means the location of the Project as described in the Cover Sheet.

1.251 “Start-up” means the action of bringing a Unit from non-operation to operation at or above the Unit’s Minimum Load, or with positive generation output if Minimum Load is zero.

1.252 “Surplus Delivered Energy” means, in any Settlement Interval, the Delivered Energy that exceeds the product of one hundred percent (100%) of Contract Capacity multiplied by a Settlement Interval.

1.253 “Supply Plan” has the meaning set forth in the CAISO Tariff.

1.254 “System Emergency” has the meaning set forth in the CAISO Tariff.

1.255 “Term” has the meaning provided in Section 2.6.

1.256 “Term Security” means for GTSR Projects with Contract Capacities 3MW or less, the Performance Assurance that Seller is required to maintain, as specified in Article Eight, to secure performance of its obligations during the Delivery Term.

1.257 “Terminated Transaction” means the Transaction terminated in accordance with Section 5.2 of this Agreement.

1.258 “Termination Payment” means the payment amount equal to the sum of (a) and (b), where (a) is the Settlement Amount and (b) is the sum of all amounts owed by the Defaulting Party to the Non-Defaulting Party under this Agreement, less any amounts owed by the Non-Defaulting Party to the Defaulting Party determined as of the Early Termination Date.

1.259 “Test Period” means the period of not more than ninety (90) consecutive days, as extended by the Initial Extension and Additional Extension according to Section 3.1(c)(ii), as applicable, which period shall commence upon the first date that the following have occurred (a) the CAISO informs Seller in writing that Seller may deliver Energy from the Project to the CAISO Grid, and (b) the items in Section 3.4(a)(i)(E) have been fulfilled and implemented, and shall end upon the Initial Energy Delivery Date.

1.260 “Third-Party SC” means a qualified third party designated by Buyer to provide the Scheduling Coordinator functions for the Project pursuant to this Agreement.

1.261 “TOD” means time of delivery of Delivered Energy from Seller to Buyer.

1.262 “TOD Factors” has the meaning set forth in Section 4.4(a).

1.263 “TOD Periods” has the meaning set forth in Section 4.2.

1.264 “Transaction” means the particular transaction described in its entirety in Section 3.1(b) of this Agreement.

1.265 “Transfer” with respect to Letters of Credit means the delivery of the Letter of Credit conforming to the requirements of this Agreement, by Seller or an Eligible LC Bank to Buyer or delivery of an executed amendment to such Letter of Credit (extending the term or varying the amount available to Buyer thereunder, if acceptable to Buyer) by Seller or Eligible LC Bank to Buyer.

1.266 “Transmission Delay” has the meaning set forth in Section 3.9(c)(ii)(B).

1.267 “Transmission Provider” means any entity or entities transmitting or transporting the Product on behalf of Seller or Buyer to or from the Delivery Point.

1.268 “Uninstructed Imbalance Energy” shall have the meaning set forth in the CAISO Tariff.

1.269 “Unit” means the technology used to produce the Products, which are identified in the Cover Sheet for the Transaction entered into under this Agreement.

1.270 “Variation(s)” means the absolute value of the difference, in MWh, in any Settlement Interval between (a) DA Scheduled Energy; and (b) Delivered Energy for the Settlement Interval. ***[For Baseload Product only]***

1.271 “WECC” means the Western Electricity Coordinating Council or successor agency.

1.272 “Work” means (a) work or operations performed by a Party or on a Party’s behalf, and (b) materials, parts or equipment furnished in connection with such work or operations, including (i) warranties or representations made at any time with respect to the fitness, quality, durability, performance or use of “a Party’s work”, and (ii) the providing of or failure to provide warnings or instructions.

1.273 “WREGIS” means the Western Renewable Energy Generation Information System or any successor renewable energy tracking program.

1.274 “WREGIS Certificate Deficit” has the meaning set forth in Section 3.1(k)(v).

1.275 “WREGIS Certificates” has the same meaning as “Certificate” as defined by WREGIS in the WREGIS Operating Rules and are designated as eligible for complying with the California Renewables Portfolio Standard.

1.276 “WREGIS Operating Rules” means those operating rules and requirements adopted by WREGIS as of December 2010, as subsequently amended, supplemented or replaced (in whole or in part) from time to time.

ARTICLE TWO: GOVERNING TERMS AND TERM

2.1 Entire Agreement. This Agreement, together with the Cover Sheet, Preamble and each and every appendix, attachment, amendment, schedule and any written supplements hereto, if any, between the Parties constitutes the entire, integrated agreement between the Parties.

2.2 Interpretation. The following rules of interpretation shall apply in addition to those set forth in Section 10.13:

(a) The term “month” or “Month” shall mean a calendar month unless otherwise indicated, and a “day” shall be a 24-hour period beginning at 12:00:01 a.m. Pacific Prevailing Time and ending at 12:00:00 midnight Pacific Prevailing Time; provided that a “day” may be 23 or 25 hours on those days on which daylight savings time begins and ends.

(b) Unless otherwise specified herein, all references herein to any agreement or other document of any description shall be construed to give effect to amendments, supplements, modifications or any superseding agreement or document as then existing at the applicable time to which such construction applies.

(c) Capitalized terms used in this Agreement, including the appendices hereto, shall have the meaning set forth in Article One, unless otherwise specified.

(d) Unless otherwise specified herein, references in the singular shall include references in the plural and vice versa, pronouns having masculine or feminine gender will be deemed to include the other, and words denoting natural persons shall include partnerships, firms, companies, corporations, joint ventures, trusts, associations, organizations or other entities (whether or not having a separate legal personality). Other grammatical forms of defined words or phrases have corresponding meanings.

(e) References to a particular article, section, subsection, paragraph, subparagraph, appendix or attachment shall, unless specified otherwise, be a reference to that article, section, subsection, paragraph, subparagraph, appendix or attachment in or to this Agreement.

(f) Any reference in this Agreement to any natural person, Governmental Authority, corporation, partnership or other legal entity includes its permitted successors and assigns or any natural person, Governmental Authority, corporation, partnership or other legal entity succeeding to its functions.

(g) All references to dollars are to U.S. dollars.

(h) The term “including” when used in this Agreement shall be by way of example only and shall not be considered in any way to be in limitation.

2.3 Authorized Representatives. Each Party shall provide Notice to the other Party of the persons authorized to nominate and/or agree to a Schedule or dispatch order for the delivery or acceptance of the Product or make other Notices on behalf of such Party and specify the scope of their individual authority and responsibilities, and may change its designation of such persons from time to time in its sole discretion by providing Notice.

2.4 Separation of Functions. The Parties acknowledge that this Agreement is between (a) Seller and (b) Buyer acting solely in its merchant function. The Parties further acknowledge that they have no rights against each other or obligations to each other under this Agreement with respect to any relationship between the Parties in which PG&E is acting in its capacity as Participating Transmission Owner, including orders or instructions relating to Electric System Upgrades and/or Curtailment Periods.

2.5 Conditions Precedent.

(a) Conditions Precedent. Subject to Section 2.7 hereof, the Term shall not commence until the occurrence of all of the following:

(i) this Agreement has been duly executed by the authorized representatives of each of Buyer and Seller;

(ii) CPUC Approval has been obtained for the terms, conditions and pricing of this Agreement;

(iii) the advice letter submitting this Agreement to the CPUC becomes effective in accordance with CPUC General Order 96-B or its successor order, or as otherwise provided by CPUC order; and

(iv) Buyer receives from Seller the documentation listed in Appendix VIII (Seller Documentation Condition Precedent).

(b) Failure to Meet All Conditions Precedent. If the Conditions Precedent set forth in Sections 2.4(a)(ii) and (iii) are not satisfied or waived in writing by both Parties on or before one hundred and eighty (180) days from the date on which Buyer files an advice letter submitting this Agreement to the CPUC, then either Party may terminate this Agreement effective upon receipt of Notice by the other Party. Neither Party shall have any obligation or liability to the other, including for a Termination Payment or otherwise, by reason of such termination.

2.6 Term.

(a) The term shall commence upon the satisfaction of the Conditions Precedent set forth in Section 2.5(a) of this Agreement and shall remain in effect until the conclusion of the Delivery Term unless terminated sooner pursuant to Section 2.5(b), Section 5.2 or Section 11.1 of this Agreement (the “Term”); provided that this Agreement shall thereafter remain in effect (i) until the Parties have fulfilled all obligations with respect to the Transaction, including payment in full of amounts due pursuant to the Final True-Up, the Settlement Amount, or other damages (whether directly or indirectly such as through set-off or netting) and the undrawn portion of the Project Development Security, Delivery Term Security or Term Security as applicable, is released and/or returned as applicable (the “Satisfaction Date”) or (ii) in accordance with the survival provisions set forth in subpart (b) below.

(b) Notwithstanding anything to the contrary in this Agreement, (i) all rights under Section 10.5 (“Indemnities”) and any other indemnity rights shall survive the Satisfaction Date or the end of the Term (whichever is later) for an additional twelve (12) months; (ii) all rights and obligations under Section 10.7 (“Confidentiality”) shall survive the Satisfaction Date or the end of the Term (whichever is later) for an additional two (2) years; and (iii) the right of first offer in Section 11.1(b) shall survive the Satisfaction Date for three (3) years.

2.7 Binding Nature.

(a) Upon Execution Date. This Agreement shall be effective and binding as of the Execution Date only to the extent required to give full effect to, and enforce, the rights and obligations of the Parties under:

(i) Sections 3.9(a)(vii), 5.1(a)(iv)-(v), and 5.1(b)(iv);

(ii) Section 5.1(a)(ii) only with respect to Section 10.2, and Section 5.1(a)(iii) only with respect to the Sections identified in this Section 2.7;

(iii) Sections 5.2 through 5.7;

- (iv) Sections 8.3, 8.4(a)(i), 8.4(b), and 8.5;
- (v) Sections 10.2, 10.6 through 10.8, and Sections 10.12 through 10.16; and
- (vi) Articles One, Two, Seven, Twelve and Thirteen.

(b) Upon Effective Date. This Agreement shall be in full force and effect, enforceable and binding in all respects, upon occurrence of the Effective Date.

ARTICLE THREE: OBLIGATIONS AND DELIVERIES

3.1 Seller's and Buyer's Obligations.

(a) Product. The Product to be delivered and sold by Seller and received and purchased by Buyer under this Agreement is set forth in the Cover Sheet. Buyer shall have exclusive rights to all Product during the Delivery Term.

(b) Transaction. Unless specifically excused by the terms of this Agreement during the Delivery Term, Seller shall sell and deliver, or cause to be delivered, and Buyer shall purchase and receive, or cause to be received, the Product at the Delivery Point, pursuant to Seller's election in the Cover Sheet of a Full Buy/Sell or Excess Sale arrangement as described in paragraphs 3.1(b)(i) and 3.1(b)(ii) below. Buyer shall pay Seller the Contract Price in accordance with the terms of this Agreement. In no event shall Seller have the right (1) to procure any element of the Product from sources other than the Project for sale or delivery to Buyer under this Agreement except with respect to Energy delivered to Buyer in connection with Energy Deviations or Variations, as applicable, or (2) sell Product from the Project to a third party other than in connection with Energy Deviations or Variations, as applicable. Buyer shall have no obligation to receive or purchase Product from Seller prior to or after the Delivery Term, except during the Test Period. Seller shall be responsible for any costs or charges imposed on or associated with the Product or its delivery of the Product up to the Delivery Point. Buyer shall be responsible for any costs or charges imposed on or associated with the Product after its receipt at and from the Delivery Point. Seller shall comply with Buyer's Supplier Diversity Program in accordance with Appendix XII. Each Party agrees to act in good faith in the performance of its obligations under this Agreement.

(i) Full Buy/Sell. If "Full Buy/Sell" is elected on the Cover Sheet, Seller agrees to sell to Buyer the Project's gross output of Product measured in kilowatt-hours, net of station use and transformation and transmission losses to and at the Delivery Point. Seller shall purchase all Energy required to serve the Project's on-site load, net of station use, from Buyer or applicable retail service provider pursuant to its applicable retail rate schedule.

(ii) Excess Sale. If "Excess Sale" is selected on the Cover Sheet, Seller agrees to sell to Buyer the Project's gross output of Product as measured in kilowatt-hours, net of station Use, any on-site load and transformation and transmission losses to the Delivery Point. Seller agrees to convey to Buyer all elements of Product associated with the Energy sold to Buyer.

(c) Delivery Term.

(i) Delivery Term and Initial Energy Delivery Date. As used herein, "Delivery Term" shall mean the period of Contract Years specified on the Cover Sheet, beginning on the first date that Buyer accepts delivery of the Product from the Project in connection with this Agreement following Seller's demonstration of satisfaction of the items listed below in this Section 3.1(c)(i) ("Initial

Energy Delivery Date”) and continuing until the end of the tenth, fifteenth, or twentieth Contract Year (as applicable, based on the Cover Sheet election) unless terminated pursuant to the terms of this Agreement; provided that the Expected Initial Energy Delivery Date may be extended pursuant to Section 3.1(c)(ii). The Initial Energy Delivery Date shall be the later of the (A) date that the Buyer receives the "Initial Energy Delivery Date Confirmation Letter" attached hereto as Appendix II and (B) the date listed as the Initial Energy Delivery Date on the Initial Energy Delivery Date Confirmation Letter. The Initial Energy Delivery Date shall occur as soon as practicable once all of the following have been satisfied: (I) Seller notifies Buyer that Commercial Operation has occurred; (II) Buyer shall have received and accepted the Delivery Term Security or Term Security, as applicable, in accordance with the relevant provisions of Article Eight of the Agreement, as applicable; (III) Seller shall have obtained the requisite CEC Certification and Verification for the Project [and Seller shall have demonstrated submission and approval of documents and information to CRS necessary for the GTSR Project to receive an eligibility designation for Buyer’s Green-e® Energy Certification][*Bracketed language only applies to GTSR Projects*] (IV) all of the applicable Conditions Precedent in Section 2.5(a) have been satisfied or waived in writing; (V) for resources that are already under a contract as of the Execution Date, that existing contract must have expired by its own terms before the Initial Energy Delivery Date; (VI) Seller shall have demonstrated satisfaction of Seller’s other obligations in this Agreement that commence prior to or as of the Delivery Term; and (VII) unless Seller has been directed by Buyer to not participate in the Participating Intermittent Resource Program, Buyer shall have received written notice from the CAISO that the Project is certified as a Participating Intermittent Resource to the extent the Participating Intermittent Resource Program exists for the Project’s technology type at such time as the conditions in subsections (I) through (VI) of this Section 3.1(c)(i) are satisfied. [*Subsection (VII) applicable to solar, wind, or hydro Projects only*]

(ii) Extensions of Test Period and Initial Energy Delivery Date. In the event that Seller cannot satisfy the requirements for the Initial Energy Delivery Date by the Expected Initial Energy Delivery Date, as set forth in Section 3.1(c)(i), then Seller may provide Buyer with a one-time Notice of a thirty (30) day extension of the Test Period and Expected Initial Energy Delivery Date (“Initial Extension”) along with a written explanation of the basis for the extension, no later than five (5) Business Days prior to the Expected Initial Energy Delivery Date. In the event that Seller requires an additional extension of the Test Period and Expected Initial Energy Delivery Date beyond the Initial Extension, Seller may request a further extension of the Test Period and Expected Initial Energy Delivery Date from Buyer no later than ten (10) days prior to the expiration of the Initial Extension of up to sixty (60) days by providing Notice to Buyer along with a detailed written explanation of the basis for such request (“Additional Extension”). Buyer shall provide Seller with Notice of Buyer’s acceptance or rejection, in its sole discretion, of such Notice of Additional Extension within ten (10) days of receipt of Seller’s Notice of Additional Extension. If Buyer fails to provide a Notice of Buyer’s acceptance or rejection, then Seller’s Notice of Additional Extension shall be deemed accepted. If Buyer provides Seller with Notice of Buyer’s rejection of the Additional Extension, then Seller may be subject to an Event of Default. As evidence of the Initial Energy Delivery Date, the Parties shall execute and exchange the “Initial Energy Delivery Date Confirmation Letter,” attached hereto as Appendix II, on the Initial Energy Delivery Date.

(d) Delivery Point. The Delivery Point shall be the PNode designated by the CAISO for the Project.

(e) Contract Quantity and Guaranteed Energy Production.

(i) Contract Quantity. The Contract Quantity during each Contract Year is the amount set forth in the applicable Contract Year in Section D of the Cover Sheet (“Delivery Term Contract Quantity Schedule”), which amount is inclusive of outages.

[Use the following bracketed language for As-Available Product delivered by all facilities]

[(ii) Guaranteed Energy Production.

(A) Throughout the Delivery Term, Seller shall be required to provide to Buyer an amount of Delivered Energy plus Deemed Delivered Energy, if any, no less than the Guaranteed Energy Production over two (2) consecutive Contract Years during the Delivery Term (“Performance Measurement Period”). “Guaranteed Energy Production” is equal to the product of (x) and (y), where (x) is one hundred sixty percent (160%) of the average of the Contract Quantities applicable to the two (2) Contract Years comprising the Performance Measurement Period ***[Photovoltaic facilities only to use the then-applicable Contract Quantities for the Performance Measurement Period]***, and (y) is the difference between (I) and (II), with the resulting difference divided by (I), where (I) is the number of hours in the applicable Performance Measurement Period and (II) is the aggregate number of Seller Excuse Hours in the applicable Performance Measurement Period. Guaranteed Energy Production is described by the following formula:

Guaranteed Energy Production = $(160\% \times \text{average of the Contract Quantities in MWh in Performance Measurement Period}) \times [(\text{Hrs in Performance Measurement Period} - \text{Seller Excuse Hrs in Performance Measurement Period}) / \text{Hrs in Performance Measurement Period}]$]

[Use the following bracketed language for Baseload Product only]

[(ii) Guaranteed Energy Production.

(A) Throughout the Delivery Term, Seller shall be required to provide to Buyer an amount of Delivered Energy plus Deemed Delivered Energy, if any, no less than the Guaranteed Energy Production in each Contract Year during the Delivery Term (“Performance Measurement Period”). “Guaranteed Energy Production” is equal to the product of (x) and (y), where (x) is ninety percent (90%) of the Contract Quantity, and (y) is the difference between (I) and (II), with the resulting difference divided by (I), where (I) is the number of hours in the applicable Performance Measurement Period and (II) is the aggregate number of Seller Excuse Hours in the applicable Performance Measurement Period. Guaranteed Energy Production is described by the following formula:

Guaranteed Energy Production = $(90\% \times \text{Contract Quantity in MWh}) \times [(\text{Hrs in Performance Measurement Period} - \text{Seller Excuse Hrs in Performance Measurement Period}) / \text{Hrs in Performance Measurement Period}]$]

[Use the following subparts (B) and (C) to Section 3.1(e)(ii) for both As-Available and Baseload Products and all technologies]

(B) In no event shall any amount of Delivered Energy plus Deemed Delivered Energy in any Settlement Interval that exceeds the Contract Capacity be credited toward or added to Seller’s Guaranteed Energy Production requirement.

(C) GEP Failure, Cure, Damages.

(I) If Seller has a GEP Failure, then within forty-five (45) days after the last day of the last month of such Performance Measurement Period, Buyer shall promptly provide Notice to Seller of such failure, provided that Buyer’s failure to provide Notice shall not constitute as a waiver of Buyer’s rights to collect GEP damages. Seller may cure the GEP Failure by providing to Buyer an amount of Delivered Energy plus Deemed Delivered Energy, if any, that is no less than ninety percent (90%) of the Contract Quantity, subject to adjustment for Seller Excuse Hours over the next following Contract Year, as set forth in the formula below (“GEP Cure”).

GEP Cure = $(90\% \times \text{Contract Quantity in MWh}) \times [(\text{Hrs in next following Contract Year} - \text{Seller Excuse Hrs in next following Contract Year}) / \text{Hrs in next following Contract Year}]$

If Seller fails to provide sufficient Delivered Energy plus Deemed Delivered Energy, if any, as adjusted by Seller Excuse Hours, to qualify for the GEP Cure for a given Performance Measurement Period, Seller shall pay GEP Damages, calculated pursuant to Appendix V (“GEP Damages Calculation”). If Seller provides a GEP Cure or pays GEP Damages for the Contract Years in a particular Performance Measurement Period (“Cured Performance Measurement Period”), then for purposes of calculating the Guaranteed Energy Production in the following Performance Measurement Period, the amount of Delivered Energy plus Deemed Delivered Energy in the second Contract Year of the Cured Performance Measurement Period, which is also the first Contract Year of the following Performance Measurement Period (“Shared Contract Year”), shall be deemed equal to the greater of (X) the Delivered Energy plus Deemed Delivered Energy, if any, for the Shared Contract Year, subject to adjustment for Seller Excuse Hours, or (Y) eighty percent (80%) of Contract Quantity in the Shared Contract Year, where X and Y are calculated as follows:

$X = (\text{Delivered Energy} + \text{Deemed Delivered Energy in Shared Contract Year}) \times [\text{Hrs in Shared Contract Year} / (\text{Hrs in Shared Contract Year} - \text{Seller Excuse Hours in Shared Contract Year})]$ or;

$Y = 80\% \times \text{Contract Quantity in Shared Contract Year}$

For the avoidance of doubt, the calculation set forth above for the amount of Delivered Energy plus Deemed Delivered Energy for the Shared Contract Year shall not apply to the cumulative GEP Shortfall under Section 5.1(b)(vi)(B).]

[Bracketed text above applies to As-Available Product only.]

(II) The Parties agree that the damages sustained by Buyer associated with Seller’s failure to achieve the Guaranteed Energy Production requirement would be difficult or impossible to determine, or that obtaining an adequate remedy would be unreasonably time consuming or expensive and therefore agree that Seller shall pay the GEP Damages to Buyer as liquidated damages. In no event shall Buyer be obligated to pay GEP Damages.

(III) After the GEP Cure period has run, if Seller has not achieved the GEP Cure, Buyer shall have forty-five (45) days to notify Seller of such failure. Within forty-five (45) days of the end of the GEP Cure period, Buyer shall provide Notice to Seller in writing of the amount of the GEP Damages, if any, which Seller shall pay within sixty (60) days of receipt of the Notice (the “Cure Payment Period”). If Seller does not pay the GEP Damages within the Cure Payment Period, then Buyer may, at its option, declare an Event of Default pursuant to Section 5.1(b)(vi)(A) within ninety (90) days following the Cure Payment Period. If Seller has failed to pay the GEP Damages, and Buyer does not (1) notify Seller of the GEP Failure or (2) declare an Event of Default pursuant to Section 5.1(b)(vi) within the ninety (90) day period, then Buyer shall be deemed to have waived its right to declare an Event of Default based on Seller’s failure with respect to the Performance Measurement Period which served as the basis for the notice of GEP Failure, GEP Damages, or default, subject to the limitations set forth in Section 5.1(b)(vi)(B).

[The following bracketed version of Section 3.1(f) “Contract Capacity” applies to Full Buy/Sell transactions of As-Available Product only]

[(f) Contract Capacity. The generation capability designated for the Project shall be the contract capacity in MW designated in the Cover Sheet, (the “Contract Capacity”), which shall be equal to the result of the Contract Capacity calculation performed in accordance with Section II of

Appendix XIII. Throughout the Delivery Term, Seller shall sell and deliver all Product produced by the Project solely to Buyer. In no event shall Buyer be obligated to receive, in any Settlement Interval, any Surplus Delivered Energy. Seller shall not receive payment for any Surplus Delivered Energy. To the extent Seller delivers Surplus Delivered Energy to the Delivery Point in a Settlement Interval in which the Real-Time Price for the applicable PNode is negative, Seller shall pay Buyer an amount equal to the Surplus Delivered Energy (in MWh) during such Settlement Interval, multiplied by the absolute value of the Real-Time Price per MWh for such Settlement Interval.]

[The following bracketed version of Section 3.1(f) “Contract Capacity” applies to all Baseload Products and Excess Sale transactions of As-Available Products.]

[(f) Contract Capacity.

(i) Contract Capacity. The capacity of the Project at any time shall be the lower of the following: (A) the contract capacity in MW designated in the Cover Sheet or (B) the Net Rated Output Capacity of the Project (the “Contract Capacity”), which shall be equal to the result of the Contract Capacity calculation performed in accordance with Section II of Appendix XIII. Throughout the Delivery Term, Seller shall sell all Product produced by the Project solely to Buyer. In no event shall Buyer be obligated to receive, in any Settlement Interval, any Surplus Delivered Energy. Seller shall not receive payment for any Surplus Delivered Energy. To the extent Seller delivers Surplus Delivered Energy to the Delivery Point in a Settlement Interval in which the Real-Time Price for the applicable PNode is negative, Seller shall pay Buyer an amount equal to the Surplus Delivered Energy (in MWh) during such Settlement Interval, multiplied by the absolute value of the Real-Time Price per MWh for such Settlement Interval.

(ii) Net Rated Output Capacity Testing. Buyer shall have the right to request a Capacity Test as set forth in Appendix IV-3, to determine the Net Rated Output Capacity no more than one time per Contract Year. The resulting Net Rated Output Capacity shall be used to determine the Contract Capacity, in accordance with Section 3.1(f)(i) above, and shall remain in effect until the next Capacity Test requested by Buyer. Appendix IV-3 sets forth the agreements of Buyer and Seller with respect to the performance of Capacity Tests.]

(g) Project.

(i) All Product provided by Seller pursuant to this Agreement shall be supplied from the Project only. Seller shall not make any alteration or modification to the Project which results in a change to the Contract Capacity or the anticipated output of the Project without Buyer’s prior written consent. The Project is further described in Appendix XIII.

(ii) Seller shall not relinquish its possession or demonstrable exclusive right to control the Project without the prior written consent of Buyer, except under circumstances provided in Section 10.6.

Seller shall be deemed to have relinquished possession of the Project if after the Commercial Operation Date Seller has ceased work on the Project or ceased production and delivery of Product for a consecutive thirty (30) day period and such cessation is not a result of a Force Majeure event or direct action of Buyer.

(h) Interconnection Facilities.

(i) Seller Obligations. Seller shall (A) arrange and pay independently for any and all necessary costs under any Generator Interconnection Agreement with the Participating Transmission Owner; (B) cause the Interconnection Customer's Interconnection Facilities, including metering facilities, to be maintained; and (C) comply with the procedures set forth in the GIP and applicable agreements or procedures provided under the GIP in order to obtain the applicable Electric System Upgrades and (D) obtain Electric System Upgrades, as needed, in order to ensure the safe and reliable delivery of Energy from the Project up to and including quantities that can be produced utilizing all of the Contract Capacity of the Project.

(ii) Coordination with Buyer.

(A) Seller shall (I) provide to Buyer copies of all material correspondence related thereto; and (II) provide Buyer with written reports of the status of the GIA on a monthly basis. The foregoing shall not preclude Seller from executing a GIA that it reasonably determines allows it to comply with its obligations under this Agreement and applicable Law.

(B) Excess Network Upgrade Costs. Seller shall provide Buyer within ten (10) Business Days of receipt thereof, copies of any Interconnection Study or the interconnection agreement tendered to Seller by the Participating Transmission Owner that may give rise to a termination right of Buyer under Section 3.9(f)(i). Within that same period Seller shall also provide Buyer a Notice of its irrevocable election to exercise or not exercise its right to assume financial responsibility for any Excess Network Upgrade Cost pursuant to Section 3.9(f)(i), with a failure to provide such an election deemed to be an election not to exercise such rights for purposes of administration and enforcement of the terms of this Agreement.

(i) Performance Excuses.

(i) Seller Excuse. For Seller selling As-Available Product, Seller shall be excused from achieving the Guaranteed Energy Production only for the applicable time period during Seller Excuse Hours. For Seller selling Baseload Product, Seller shall be excused from achieving the Guaranteed Energy Production and the Capacity Factor only for the applicable time period during Seller Excuse Hours.

(ii) Buyer Excuses. Buyer shall be excused from (A) receiving and paying for the Product only (I) during periods of Force Majeure, (II) by Seller's failure to perform, (III) during Curtailment Periods and (B) receiving Product during Buyer Curtailment Periods.

(iii) Curtailment. Notwithstanding Section 3.1(b) and this Section 3.1(i), Seller shall reduce output from the Project during any Curtailment Period or Buyer Curtailment Period.

(j) Greenhouse Gas Emissions Reporting. During the Term, Seller acknowledges that a Governmental Authority may require Buyer to take certain actions with respect to greenhouse gas emissions attributable to the generation of Energy, including reporting, registering, tracking, allocating for or accounting for such emissions. Promptly following Buyer's written request, Seller agrees to take all commercially reasonable actions and execute or provide any and all documents, information or instruments with respect to generation by the Project reasonably necessary to permit Buyer to comply with such requirements, if any, subject to the Compliance Cost Cap. Nothing in this Section 3.1(j) shall cause Buyer to assume any liability or obligation with respect to Seller's compliance obligations with respect to the Project under any new or existing Laws, rules, or regulations.

(k) WREGIS. Seller shall, at its sole expense, but subject to the Compliance Cost Cap, take all actions and execute all documents or instruments necessary to ensure that all WREGIS Certificates associated with all Renewable Energy Credits corresponding to all Delivered Energy are issued and tracked for purposes of satisfying the requirements of the California Renewables Portfolio Standard and transferred in a timely manner to Buyer for Buyer's sole benefit. Seller shall transfer the Renewable Energy Credits to Buyer even if Buyer does not accept and/or pay for the underlying energy per Section 3.1(f) or for Baseload Product only, pays something other than the Contract Price. Seller shall comply with all Laws, including the WREGIS Operating Rules, regarding the certification and transfer of such WREGIS Certificates to Buyer and Buyer shall be given sole title to all such WREGIS Certificates. Seller shall be deemed to have satisfied the warranty in Section 3.1(k)(viii), provided that Seller fulfills its obligations under Sections 3.1(k)(i) through (vii) below. In addition:

(i) Prior to the Initial Energy Delivery Date, Seller shall register the Project with WREGIS and establish an account with WREGIS ("Seller's WREGIS Account"), which Seller shall maintain until the end of the Delivery Term. Seller shall transfer the WREGIS Certificates using "Forward Certificate Transfers" (as described in the WREGIS Operating Rules) from Seller's WREGIS Account to the WREGIS account(s) of Buyer or the account(s) of a designee that Buyer identifies by Notice to Seller ("Buyer's WREGIS Account"). Seller shall be responsible for all expenses associated with registering the Project with WREGIS, establishing and maintaining Seller's WREGIS Account, paying WREGIS Certificate issuance and transfer fees, and transferring WREGIS Certificates from Seller's WREGIS Account to Buyer's WREGIS Account.

(ii) Seller shall cause Forward Certificate Transfers to occur on a monthly basis in accordance with the certification procedure established by the WREGIS Operating Rules. Since WREGIS Certificates will only be created for whole MWh amounts of Energy generated, any fractional MWh amounts (i.e., kWh) will be carried forward until sufficient generation is accumulated for the creation of a WREGIS Certificate.

(iii) Seller shall, at its sole expense, ensure that the WREGIS Certificates for a given calendar month correspond with the Delivered Energy for such calendar month as evidenced by the Project's metered data.

(iv) Due to the ninety (90) day delay in the creation of WREGIS Certificates relative to the timing of invoice payment under Article 6, Buyer shall make an invoice payment for a given month in accordance with Article 6 before the WREGIS Certificates for such month are formally transferred to Buyer in accordance with the WREGIS Operating Rules and this Section 3.1(k). Notwithstanding this delay, Buyer shall have all right and title to all such WREGIS Certificates upon payment to Seller in accordance with Article 6.

(v) A "WREGIS Certificate Deficit" means any deficit or shortfall in WREGIS Certificates delivered to Buyer for a calendar month as compared to the Delivered Energy for the same calendar month ("Deficient Month"). If any WREGIS Certificate Deficit is caused, or the result of any action or inaction, by Seller, then the amount of Delivered Energy in the Deficient Month shall be reduced by the amount of the WREGIS Certificate Deficit for the purposes of calculating Buyer's payment(s) to Seller under Article 6 and the Guaranteed Energy Production for the applicable Performance Measurement Period. Any amount owed by Seller to Buyer because of a WREGIS Certificate Deficit shall be made as an adjustment to Seller's next monthly invoice to Buyer in accordance with Article 6, and Buyer shall net such amount against Buyer's subsequent payment(s) to Seller pursuant to Article 6.

(vi) Without limiting Seller's obligations under this Section 3.1(k), if a WREGIS Certificate Deficit is caused solely by an error or omission of WREGIS, the Parties shall cooperate in good faith to cause WREGIS to correct its error or omission.

(vii) If WREGIS changes the WREGIS Operating Rules after the Execution Date or applies the WREGIS Operating Rules in a manner inconsistent with this Section 3.1(k) after the Execution Date, the Parties promptly shall modify this Section 3.1(k) as reasonably required to cause and enable Seller to transfer to Buyer's WREGIS Account a quantity of WREGIS Certificates for each given calendar month that corresponds to the Delivered Energy in the same calendar month.

(viii) Seller warrants that all necessary steps to allow the Renewable Energy Credits transferred to Buyer to be tracked in the Western Renewable Energy Generation Information System will be taken prior to the first delivery under the contract.

(l) Access to Data and Installation and Maintenance of Weather Station.

(i) Commencing on the first date on which the Project generates Product to be delivered to the CAISO Grid or the Delivery Point, if different, and continuing throughout the Term, Seller shall provide to Buyer, in a form reasonably acceptable to Buyer, the data set forth below on a real-time basis; provided that Seller shall agree to make and bear the cost of changes to any of the data delivery provisions below, as requested by Buyer, throughout the Term, which changes Buyer determines are necessary to forecast output from the Project, and/or comply with Law:

(A) read-only access to meteorological measurements, *[inverter]* ***[bracketed language applies to solar photovoltaic Projects only]*** and transformer availability, any other facility availability information, all parameters necessary for use in the equation under item (G) of this list;

(B) read-only access to energy output information collected by the supervisory control and data acquisition (SCADA) system for the Project; provided that if Buyer is unable to access the Project's SCADA system, then upon written request from Buyer, Seller shall provide energy output information and meteorological measurements to Buyer in 1-minute intervals in the form of a flat file to Buyer through a secure file transport protocol (FTP) system with an e-mail back up for each flat file submittal;

(C) read-only access to the Project's CAISO revenue meter and all Project meter data at the Site;

(D) full, real-time access to the Project's Scheduling and Logging for the CAISO (SLIC) client application, or its successor system;

(E) net plant electrical output at the CAISO revenue meter;

[Subparts (F) through (G) below shall only apply to wind and solar facilities]

(F) instantaneous data measurements at sixty (60) second or increased frequency for the parameters set forth in Appendix X ("Telemetry Parameters for Wind or Solar Facilities"), which measurements shall be provided by Seller to Buyer in consolidated data report at least once every five minutes via flat file through a secure file transport protocol (FTP) system with an e-mail backup; and

(G) an equation, updated on an ongoing basis to reflect the potential generation of the Project as a function of ***[the following bracketed language applies to solar facilities only]*** [solar insolation, temperature, wind speed, and, if applicable, wind direction] ***[the following bracketed language applies to wind facilities only]*** [wind speed, wind direction, ambient temperature, atmospheric pressure]. Such equation shall take into account the expected availability of the facility.

[The following bracketed language applies to As-Available Product only]

[For any month in which the above information and access was not available to Buyer for longer than twenty-four (24) continuous hours, Seller shall prepare and provide to Buyer upon Buyer's request a report with the Project's monthly Settlement Interval Actual Available Capacity in the form set forth in Appendix IX ("Actual Availability Report"). Upon Buyer's request, Seller shall promptly provide to Buyer any additional and supporting documentation necessary for Buyer to audit and verify any matters set forth in the Actual Availability Report.] Buyer shall exercise commercially reasonable efforts to notify Seller of any deficiency by Seller in meeting the requirements of this Section 3.1(l)(i); provided that any failure by Buyer to provide such deficiency notice shall not result in any additional liability to Buyer under this Agreement.

(ii) Buyer reserves the right to validate the data provided pursuant to Section 3.1(l)(i) with information publicly available from NOAA and nearby weather stations and substitute such data for its scheduling purposes if Seller's data is inconsistent with the publicly available data or is missing; provided that Buyer shall notify Seller promptly of Buyer's substitution of such data.

(iii) Seller shall maintain at least a minimum of one hundred twenty (120) days' historical data for all data required pursuant to Section 3.1(l)(i), which shall be available on a minimum time interval of one hour basis or an hourly average basis, except with respect to the meteorological measurements which shall be available on a minimum time interval of ten (10) minute basis. Seller shall provide such data to Buyer within five (5) Business Days of Buyer's request.

[The following Sections 3.1(l)(iv) – (vi) apply to As-Available Product only]

[(iv) Installation, Maintenance and Repair.

(A) Seller, at its own expense, shall install and maintain one (1) stand-alone meteorological station at the Site to monitor and report the meteorological data required in Section 3.1(l)(i) of this Agreement, and for wind Projects, each wind turbine must be equipped with meteorological measurement equipment (e.g. anemometers) which are individually linked to Seller's plant information system. Seller, at its own expense, shall install and maintain a secure communication link in order to provide Buyer with access to the data required in Section 3.1(l)(i) of this Agreement.

(B) Seller shall maintain the meteorological stations, telecommunications path, hardware, and software necessary to provide accurate data to Buyer or Third-Party SC (as applicable) to enable Buyer or the Third-Party SC to meet current CAISO scheduling requirements. Seller shall promptly repair and replace as necessary such meteorological stations, telecommunications path, hardware and software and shall notify Buyer as soon as Seller learns that any such telecommunications paths, hardware and software are providing faulty or incorrect data.

(C) If Buyer notifies Seller of the need for maintenance, repair or replacement of the meteorological stations, telecommunications path, hardware or software, Seller shall maintain, repair or replace such equipment as necessary within five (5) days of receipt of such Notice.

(D) For any occurrence in which Seller's telecommunications system is not available or does not provide quality data and Buyer notifies Seller of the deficiency or Seller becomes aware of the occurrence, Seller shall transmit data to Buyer through any alternate means of verbal or written communication, including cellular communications from onsite personnel, facsimile, blackberry or equivalent mobile e-mail, or other method mutually agreed upon by the Parties, until the telecommunications link is re-established.

(v) Seller agrees and acknowledges that Buyer may seek from third parties any information relevant to its duties as SC for Seller, including from the Participating Transmission Operator. Seller hereby voluntarily consents to allow the Participating Transmission Operator to share Seller's information with Buyer in furtherance of Buyer's duties as SC for Seller, and agrees to provide the Participating Transmission Owner with written confirmation of such voluntary consent at least ninety (90) days prior to the Initial Energy Delivery Date.

(vi) No later than ninety (90) days before the Initial Energy Delivery Date, Seller shall provide one (1) year, if available, but no less than six (6) months, of recorded meteorological data to Buyer in a form reasonably acceptable to Buyer from a weather station at the Site. Such weather station shall provide, via remote access to Buyer, all data relating to (A) ***[Include the following bracketed language for solar Projects only]*** [total global horizontal irradiance, plane of array or direct normal insolation as is applicable for project type, air temperature, wind speed and direction, precipitation, barometric pressure, visibility in fog areas (forward scatter sensor) and humidity at the Site] ***[Include the following bracketed language for wind Projects only]*** [wind speed and direction (as close to hub height as possible), standard deviation of wind direction, peak instantaneous values, air temperature, barometric pressure, and humidity at the Site], as well as time-average data including 10-minute and hourly values of irradiance or insolation, air temperature, wind speed, wind direction, standard deviation of wind direction, relative humidity, precipitation, barometric pressure ***[Include the following bracketed language only if winter season output of solar Project is an issue]*** [and visibility in fog areas] All data, except peak values, should be 1-second samples averaged into 10-minute periods; (B) elevation, latitude and longitude of the weather station; and (C) any other data reasonably requested by Buyer.]

(m) Prevailing Wage. Seller shall use reasonable efforts to ensure that all Electricians hired by Seller, Seller's contractors and subcontractors are paid wages at rates not less than those prevailing for Electricians performing similar work in the locality as provided by Division 2, Part 7, Chapter 1 of the California Labor Code. Nothing herein shall require Seller, its contractors and subcontractors to comply with, or assume liability created by other inapplicable provisions of the California Labor Code.

(n) Obtaining and Maintaining CEC Certification and Verification. Subject to the Compliance Cost Cap, Seller shall take all necessary steps including making or supporting timely filings with the CEC to obtain and maintain CEC Certification and Verification throughout the Term.

(o) Compliance Cost Cap. Costs applicable to the Compliance Cost Cap are only those costs applicable under the definition of "Compliance Costs" and are new costs associated with a change in Law occurring after the Execution Date. The Parties agree that the Compliance Costs Seller shall be required to bear during the Delivery Term shall be capped annually at ten thousand dollars (\$10,000.00) per MW of Contract Capacity and in the aggregate throughout the Delivery Term at twenty thousand dollars (\$20,000.00) per MW of Contract Capacity (collectively, the "Compliance Cost Cap"). In the event and to the extent that the Compliance Costs incurred by Seller exceed the Compliance Cost Cap, Buyer shall either reimburse Seller for such Compliance Costs that exceed the Compliance Cost Cap, or excuse Seller from performing the obligations of this Agreement that would otherwise cause it to incur Compliance Costs in excess of the Compliance Cost Cap. Within sixty (60) days after the change,

amendment, repeal, or enactment of Law after the Execution Date which Seller anticipates will cause it to incur Compliance Costs in excess of the Compliance Cost Cap, Seller shall provide to Buyer Notice with an estimate of the expected annual Compliance Costs caused by such change in Law. Within thirty (30) days of the delivery of such Notice with the estimate, Buyer shall provide Seller Notice of (i) Buyer's request for Seller to incur the Compliance Costs in excess of the Compliance Cost Cap, (ii) Buyer's initiation of dispute resolution under Article 12, or (iii) Buyer's waiver of Seller's performance of such obligations. The Parties shall agree on a reasonable allocation, as between Seller and Buyer, over the remaining Term of any such Compliance Costs that are incurred after the fifteenth (15th) Contract Year and that are expected to benefit the Project beyond the Term of this Agreement. Any reimbursement by Buyer to Seller referenced above in this Section 3.1(o) shall be subject to CPUC approval, and the amount of such reimbursement shall not be paid by Buyer to Seller until such time as the CPUC has approved such payment. Seller shall be relieved from performing the obligations of this Agreement that would otherwise cause it to incur Compliance Costs in excess of the Compliance Cost Cap and which give rise to the payment that is the subject of the above-referenced CPUC approval until such time as the CPUC issued its approval of the reimbursement payment in final and non-appealable form.

(p) Curtailment Requirements.

(i) Order. Seller shall reduce generation from the Project as required pursuant to a Buyer Curtailment Order, Buyer Bid Curtailment or Curtailment Order, provided that (A) a Buyer Curtailment Order, Buyer Bid Curtailment or Curtailment Order shall be consistent with the operational characteristics set forth in Section F of the Cover Sheet; (B) the Buyer Curtailment Period shall be for unlimited hours cumulatively per Contract Year (which may or may not be consecutive); and (C) Buyer shall pay Seller for Deemed Delivered Energy associated with a Buyer Curtailment Period pursuant to Article 4. Seller agrees to reduce the Project's generation by the amount and for the period set forth in the Buyer Curtailment Order, Buyer Bid Curtailment or Curtailment Order.

(ii) Failure to Comply. If Seller fails to comply with a Buyer Curtailment Order, Buyer Bid Curtailment or Curtailment Order provided in compliance with Section 3.1(p)(i), then, for each MWh of Delivered Energy that the Project generated in contradiction to the Buyer Curtailment Order, Buyer Bid Curtailment or Curtailment Order, Seller shall pay Buyer for each such MWh at an amount equal to the sum of (A) + (B) + (C), where: (A) is the amount, if any, paid to Seller by Buyer for delivery of such MWh (for example, the Contract Price adjusted by TOD Factors) and, (B) is the absolute value of the Real-Time Price for the applicable PNode, if such price is negative, for the Buyer Curtailment Period or Curtailment Period and, (C) is any penalties or other charges resulting from Seller's failure to comply with the Buyer Curtailment Order, Buyer Bid Curtailment or Curtailment Order.

(q) Seller Equipment Required for Curtailment Instruction Communications. Seller shall acquire, install, and maintain such facilities, communications links and other equipment, and implement such protocols and practices, as necessary to respond and follow instructions, including an electronic signal conveying real time and intra-day instructions, to operate the Units as directed by the Buyer and/or a Governmental Authority, including to implement a Buyer Curtailment Order, Buyer Bid Curtailment or Curtailment Order in accordance with the then-current methodology used to transmit such instructions as it may change from time to time. If at any time during the Delivery Term Seller's facilities, communications links or other equipment, protocols or practices are not in compliance with then-current methodologies, Seller shall take the steps necessary to become compliant as soon as commercially reasonably possible. Seller shall be liable pursuant to Section 3.1(p)(ii) for failure to comply with a Buyer Curtailment Order, Buyer Bid Curtailment or Curtailment Order, during the time that Seller's facilities, communications links or other equipment, protocols or practices are not in compliance with then-current methodologies. For the avoidance of doubt, a Buyer Curtailment Order,

Buyer Bid Curtailment or Curtailment Order communication via such systems and facilities shall have the same force and effect on Seller as any other form of communication.

[The following bracketed section only applies to GTSR Projects]

[(r) Green-e® Energy Certification.

(i) As of the Effective Date, Seller represents and warrants that (A) the Project is eligible for Green-e® Energy Certification and (B) the WREGIS Certificates associated with the Renewable Energy Credits corresponding to Delivered Energy have not been separately sold, separately marketed or otherwise separately represented by Seller or its Affiliates as renewable energy attributable to the Project other than to Buyer.

(ii) From the Execution Date, and for the duration of the Delivery Term, Seller covenants that it shall, at its sole expense, but subject to the Compliance Cost Cap, take all actions, including complying with all applicable registration, attestation, eligibility, auditing, and reporting requirements, and execute all documents or instruments necessary (A) to be eligible for and maintain the Green-e® Energy Certification during the Delivery Term, and (B) to enable Buyer to meet its obligation for a GTSR Program with Green-e® Energy Certification during the Delivery Term.]

3.2 Green Attributes.

(a) Seller hereby provides and conveys all Green Attributes associated with all electricity generation from the Project to Buyer as part of the Product being delivered. Seller represents and warrants that Seller holds the rights to all Green Attributes from the Project, and Seller agrees to convey and hereby conveys all such Green Attributes to Buyer as included in the delivery of the Product from the Project.

(b) Biomethane Transactions.

(i) For all electric generation using biomethane as fuel, Seller shall transfer to Buyer sufficient renewable and environmental attributes of biomethane production and capture to ensure that there are zero net emissions associated with the production of electricity from the generating facility using the biomethane.

(ii) For all electric generation using biomethane as fuel, neither Buyer nor Seller may make a marketing, regulatory, or retail claim that asserts that a procurement contract to which that entity was a party resulted, or will result, in greenhouse gas reductions related to the destruction of methane if the capture and destruction is required by Law. If the capture and destruction of the biomethane is not required by Law, neither Buyer nor Seller may make a marketing, regulatory, or retail claim that asserts that a procurement contract to which that entity was a party resulted, or will result, in greenhouse gas reductions related to the destruction of methane, unless the environmental attributes associated with the capture and destruction of the biomethane pursuant to that contract are transferred to Buyer and retired on behalf of the retail customers consuming the electricity associated with the use of that biomethane, or unless Seller's procurement contract with the source of biomethane prohibits the source of biomethane from separately marketing the environmental attributes associated with the capture and destruction of the biomethane sold pursuant to that contract, and such attributes have been retired.

3.3 Resource Adequacy.

(a) During the Delivery Term, Seller grants, pledges, assigns and otherwise commits to Buyer all of the Project's Contract Capacity, including Capacity Attributes from the Project, to enable Buyer to meet its Resource Adequacy or successor program requirements, as the CPUC, CAISO and/or other regional entity may prescribe, including submission of a Supply Plan or Resource Adequacy Plan ("Resource Adequacy Requirements"). From the Execution Date, and for the duration of the Delivery Term, Seller shall take all commercially reasonable actions, including complying with all applicable registration and reporting requirements, and execute any and all documents or instruments necessary to enable Buyer to use all of the capacity of the Project, including Capacity Attributes, to be committed by Seller to Buyer pursuant to this Agreement to meet Buyer's Resource Adequacy Requirements during the Delivery Term.

(b) Seller shall be responsible for all costs, charges, expenses, penalties, and obligations resulting from Resource Adequacy Standards, if applicable, and Seller shall be entitled to retain all credits, payments, and revenues, if any, resulting from Seller achieving or exceeding Resource Adequacy Standards, if applicable.

(c) Buyer shall be responsible for all costs, charges, expenses, penalties, and obligations resulting from the Replacement Capacity Rules, if applicable, provided that Seller has given Buyer Notice of the outages subject to the Replacement Capacity Rules by the earlier of ninety (90) days before the first day of the month for which the outage will occur or forty-five (45) days before Buyer's monthly Resource Adequacy capacity showing in accordance with the CAISO Tariff or decision of the CPUC. If Seller fails to provide such Notice, then Seller shall be responsible for all costs, charges, expenses, penalties, and obligations resulting from the Replacement Capacity Rules for such outage.

(d) To the extent Seller has an exemption from the Resource Adequacy Standards or the Replacement Capacity Rules under the CAISO Tariff, Sections 3.3(b) and 3.3(c) above shall not apply. If Seller would like to request an exemption for this Agreement from the CAISO, Seller shall provide to Buyer, as Seller's Scheduling Coordinator, Notice specifically requesting that Buyer seek certification or approval of this Agreement as an exempt contract pursuant to the CAISO Tariff; provided that Buyer's failure to obtain such exemption shall not be an Event of Default and Buyer shall not have any liability to Seller for such failure.

(e) Resource Adequacy Failure.

(i) RA Deficiency Determination. Notwithstanding Seller's obligations set forth in Section 3.4(a)(i)(A) or anything to the contrary herein, the Parties acknowledge and agree that:

(A) if Seller is unable to obtain the deliverability type selected in Section A of the Cover Page by the RA Start Date, then Seller shall pay to Buyer the RA Deficiency Amount for each RA Shortfall Month as liquidated damages due to Buyer for the Capacity Attributes that Seller failed to convey to Buyer; and

(B) if Seller is unable to obtain the deliverability type selected in Section A of the Cover Page by the Deliverability Finding Deadline, then Seller shall be in breach of this Agreement and subject to an Event of Default under Sections 5.1(b)(vii) - (viii), regardless of Seller's payment of any RA Deficiency Amount hereunder.

(ii) RA Deficiency Amount Calculation.

(A) Buyer shall calculate the RA Deficiency Amount for each RA Shortfall Month using the formula set forth in Section 3.3(e)(ii)(B). Buyer shall notify Seller of the RA Deficiency Amount for a given RA Shortfall Month no later than the last day of that RA Shortfall Month. The Parties agree that these liquidated damages shall be paid to Buyer for each RA Shortfall Month and constitute a reasonable approximation of the harm or loss suffered by Buyer. The Parties further agree that Buyer may use such liquidated damages for any purpose in its sole discretion. Seller shall pay the RA Deficiency Amount for a given RA Shortfall Month in the form of a deduction from the amount invoiced by Seller in such month pursuant to Section 6.1. In the event that the RA Deficiency Amount for a given RA Shortfall Month exceeds the amount invoiced pursuant to Section 6.1, Buyer shall make no payment to Seller for that month, and the difference between the invoiced amount and the RA Deficiency Amount shall be deducted from the amount(s) invoiced in the succeeding month(s) until all of the RA Deficiency Amount for such RA Shortfall Month has been deducted. Any dispute regarding Buyer's calculation of any RA Deficiency Amount shall be resolved in accordance with Article Twelve.

(B) The RA Deficiency Amount for a given RA Shortfall Month shall be equal to the product of the RA Value and the Expected Net Qualifying Capacity, as calculated in accordance with Appendix XIV. The RA Deficiency Amount is represented by the following equation:

$$\text{RA Deficiency Amount (\$/Month)} = \text{RA Value (\$/MW/Month)} \times \text{Expected Net Qualifying Capacity (MW)}$$

To the extent the Project obtains Net Qualifying Capacity that Seller applies towards its obligations under Section 3.3(a) before the Project obtains the deliverability type selected in Section A of the Cover Page (e.g., through the CAISO's Operational Deliverability Assessment), then the RA Deficiency Amount calculated above for a given RA Shortfall Month shall be reduced accordingly (e.g. the RA Deficiency Amount would equal the product of (x) the RA Value and (y) the difference between the Expected Net Qualifying Capacity and the actual Net Qualifying Capacity):

$$\text{RA Deficiency Amount (\$/Month)} = \text{RA Value (\$/MW/Month)} \times [\text{Expected Net Qualifying Capacity (MW)} - \text{actual Net Qualifying Capacity (MW)}].$$

3.4 Transmission and Scheduling.

(a) Transmission.

(i) Seller's Transmission Service Obligations. Throughout the Term, and consistent with the terms of this Agreement, Seller shall:

(A) arrange and pay independently for any and all necessary electrical interconnection, distribution and/or transmission (and any regulatory approvals required for the foregoing), sufficient to allow Seller to deliver the Product to the Delivery Point for sale pursuant to the terms of this Agreement. Seller's interconnection, distribution and/or transmission arrangements shall provide for the deliverability type selected in Section A of the Cover Sheet as of the RA Start Date and throughout the Delivery Term.

(B) If Seller has elected Energy Only Status on the Cover Sheet, this Section 3.4(a)(i)(B) is not applicable. An FCDS or PCDS Seller shall have either previously obtained, or is obligated to obtain per the terms of the Agreement, a FCDS or PCDS Finding. If Seller's Project has not attained Full Capacity Deliverability Status or Partial Capacity Deliverability Status prior to the Execution Date, Seller shall take all actions necessary or appropriate to cause the Delivery Network Upgrades necessary for it to obtain Full Capacity Deliverability Status or Partial Capacity Deliverability

Status to be constructed and placed into service. The cost of each Deliverability Assessment and any necessary Delivery Network Upgrades to ensure Full Capacity Deliverability Status or Partial Capacity Deliverability Status shall be borne solely by Seller and shall not be subject to the Compliance Cost Cap. When the CAISO advises Seller that the Project has Full Capacity Deliverability Status or Partial Capacity Deliverability Status, Seller shall Notify Buyer of such status within five (5) Business Days of the date it receives notification from the CAISO of such status by providing Buyer documentation from the CAISO. The Effective FCDS Date or Effective PCDS Date must occur on or before the Deliverability Finding Deadline; a failure to do so shall constitute an Event of Default under Section 5.1(a)(iii). The Termination Payment for an Event of Default caused by Seller's failure to achieve the Effective FCDS Date or Effective PCDS Date on or before the Deliverability Finding Deadline shall be capped at the amount of Seller's Delivery Term Security or Term Security obligation under Section 8.4(a)(ii) or (iii), as applicable.

(C) if the Project has or obtains FCDS, Seller shall Notify Buyer of such status as of the Execution Date, if applicable, or within five (5) Business Days of the date it receives notification from the CAISO of such status by providing Buyer documentation from the CAISO. If Seller has elected Energy Only Status or Partial Capacity Deliverability Status on the Cover Sheet, Seller shall continue to receive payment based on the Energy Only Status TOD Factors set forth in Section 4.4 regardless of whether or not Seller obtains FCDS.

(D) bear all risks and costs associated with such transmission service, including any transmission outages or curtailment to the Delivery Point.

(E) fulfill all contractual, metering and applicable interconnection requirements, including those set forth in the Participating Transmission Owner's applicable tariffs, the CAISO Tariff and implementing CAISO standards and requirements, so as to be able to deliver Energy from the Project according to the terms of this Agreement.

(ii) Buyer's Transmission Service Obligations. As of the Test Period and during the Delivery Term,

(A) Buyer shall arrange and be responsible for transmission service at and from the Delivery Point.

(B) Buyer shall bear all risks and costs associated with such transmission service, including any transmission outages or curtailment from the Delivery Point.

(C) Buyer shall schedule or arrange for Scheduling Coordinator services with its Transmission Providers to receive the Product at the Delivery Point.

(D) Buyer shall be responsible for all CAISO costs and charges, electric transmission losses and congestion at and from the Delivery Point.

[The following Section (b) "EIRP Requirements" applies to EIRP-eligible facilities only]

[(b) EIRP Requirements. Seller shall provide Buyer with a copy of the notice from CAISO certifying the Project as a Participating Intermittent Resource as soon as practicable after Seller's receipt of such notice of certification. As of the first date of the Test Period and until the Project receives certification as a Participating Intermittent Resource, Seller, at its sole cost, shall comply with EIRP and additional protocols issued by the CAISO for Eligible Intermittent Resources. Throughout the Delivery Term, Seller, at its sole cost, shall participate in and comply with EIRP and all additional protocols issued

by the CAISO for a Participating Intermittent Resource. Throughout the Delivery Term, Seller, at its sole cost, shall participate in and comply with all other protocols issued by the CAISO for generating facilities providing energy on an intermittent basis; provided that, if multiple options exist, then Seller shall comply with any such protocols, rules or regulations as directed by Buyer. Throughout the Delivery Term, Buyer in its limited capacity as Seller's Scheduling Coordinator shall facilitate communication with the CAISO and provide other administrative materials to CAISO as necessary to satisfy Seller's obligations as Seller's Scheduling Coordinator and to the extent such actions are at *de minimis* cost to Buyer.]

[(b)][(c)] Scheduling Coordinator. Buyer shall act as the Scheduling Coordinator for the Project. In that regard, Buyer and Seller shall agree to the following:

(i) Designation as Scheduling Coordinator.

(A) At least ninety (90) days before the beginning of the Test Period Seller shall take all actions and execute and deliver to Buyer all documents necessary to authorize or designate Buyer, or Third-Party SC, as Seller's Scheduling Coordinator, and Buyer or Third-Party SC, as applicable, shall take all actions and execute and deliver to Seller or CAISO all documents necessary to become and act as Seller's Scheduling Coordinator. If Buyer designates a Third-Party SC, then Buyer shall give Seller Notice of such designation at least ten (10) Business Days before the Third-Party SC assumes Scheduling Coordinator duties hereunder, and Seller shall be entitled to rely on such designation until it is revoked or a new Third-Party SC is appointed by Buyer upon similar Notice. Buyer shall be fully responsible for all acts and omissions of Third-Party SC and for all cost, charges and liabilities incurred by Third-Party SC to the same extent that Buyer would be responsible under this Agreement for such acts, omissions, costs, charges and liabilities if taken, omitted or incurred by Buyer directly.

(B) Seller shall not authorize or designate any other party to act as Scheduling Coordinator, nor shall Seller perform, for its own benefit, the duties of Scheduling Coordinator during the Test Period and Delivery Term.

(ii) Buyer's Responsibilities as Scheduling Coordinator. Buyer or Third-Party SC shall comply with all obligations as Seller's Scheduling Coordinator under the CAISO Tariff and shall conduct all scheduling in full compliance with the terms and conditions of this Agreement, the CAISO Tariff, and all requirements of EIRP (if applicable).

(iii) Available Capacity Forecasting. Seller shall provide the Available Capacity forecasts described below. ***[The following bracketed language applies to As-Available solar or wind Projects only]*** [Seller's availability forecasts below shall include Project availability and updated status of ***[The following bracketed language applies to solar Projects only]*** [photovoltaic panels, inverters, transformers, and any other equipment that may impact availability] or ***[The following bracketed language applies to wind Projects only]*** [transformers, wind turbine unit status, and any other equipment that may impact availability].] ***[The following bracketed language applies to As-Available Product only]*** [To avoid Forecasting Penalties set forth in Section 4.6(c)(iii).] Seller shall use commercially reasonable efforts to forecast the Available Capacity of the Project accurately and to transmit such information in a format reasonably acceptable to Buyer. Buyer and Seller shall agree upon reasonable changes to the requirements and procedures set forth below from time-to-time, as necessary to comply with CAISO Tariff changes, accommodate changes to their respective generation technology and organizational structure and address changes in the operating and Scheduling procedures of Buyer, Third-Party SC (if applicable) and the CAISO, including automated forecast and outage submissions.

(A) Annual Forecast of Available Capacity. No later than (I) the earlier of July 1 of the first calendar year following the Execution Date or one hundred and eighty (180)

days before the first day of the first Contract Year of the Delivery Term (“First Annual Forecast Date”), and (II) on or before July 1 for each calendar year from the First Annual Forecast Date for every subsequent Contract Year during the Delivery Term, Seller shall provide to Buyer and Third-Party SC (if applicable) a non-binding forecast of the hourly Available Capacity for each day in each month of the following calendar year in a form reasonably acceptable to Buyer.

(B) Monthly Forecast of Available Capacity. Seller shall provide to Buyer and Third-Party SC (if applicable), pursuant to subsections (I) and (II) below, a non-binding forecast of the hourly Available Capacity for each day of the following month in a form reasonably acceptable to Buyer:

(I) by the earlier of ninety (90) days before the beginning of the Test Period or forty-five (45) days before Buyer’s monthly Resource Adequacy capacity showing in accordance with the CAISO Tariff or decision of the CPUC, and

(II) throughout the Delivery Term, by the earlier of ninety (90) days before the beginning of each month or forty-five (45) days before Buyer’s monthly Resource Adequacy capacity showing must be completed in accordance with the CAISO Tariff or decision of the CPUC.

(C) Daily Forecast of Available Capacity. During the Test Period and thereafter during the Delivery Term, Seller or Seller’s agent shall provide a binding day ahead forecast of Available Capacity (the “Day-Ahead Availability Notice”) to Buyer or Third-Party SC (as applicable) via Buyer’s internet site, as provided in Appendix VI, for each day no later than fourteen (14) hours before the beginning of the “Preschedule Day” (as defined by the WECC) for such day. The current industry standard Preschedule Day timetable in the WECC is as follows:

- (1) Monday – Preschedule Day for Tuesday
- (2) Tuesday – Preschedule Day for Wednesday
- (3) Wednesday – Preschedule Day for Thursday
- (4) Thursday – Preschedule Day for Friday and Saturday
- (5) Friday – Preschedule Day for Sunday and Monday

Exceptions to this standard Monday through Friday Preschedule Day timetable are presently set forth by the WECC in order to accommodate holidays, monthly transitions and other events. Exceptions are posted on the WECC website (www.wecc.biz) under the document title, “Preschedule Calendar.” Each Day-Ahead Availability Notice shall clearly identify, for each hour, Seller’s forecast of all amounts of Available Capacity pursuant to this Agreement. If the Available Capacity changes by at least one (1) MW as of a time that is less than fourteen (14) hours prior to the Preschedule Day but prior to the CAISO deadline for submittal of Schedules into the Day-Ahead Market then Seller must notify Buyer of such change by telephone and shall send a revised notice to Buyer’s Internet site set forth in Appendix VI. Such Notices shall contain information regarding the beginning date and time of the event resulting in the change in Available Capacity, the expected end date and time of such event, the expected Available Capacity in MW, and any other necessary information.

If Seller fails to provide Buyer with a Day-Ahead Availability Notice as required herein, then, until Seller provides a Day-Ahead Availability Notice, Buyer may rely on the most recent Day-Ahead Forecast of Available Capacity submitted by Seller to Buyer to the extent Seller’s failure contributes to Imbalance Energy, Seller shall be subject to the Forecasting Penalties set forth in Section 4.6(c).

(D) Real-Time Available Capacity. During the Test Period and thereafter during the Delivery Term, Seller shall notify Buyer of any changes in Available Capacity of one (1) MW or more, whether due to Forced Outage, Force Majeure or other cause, as soon as reasonably possible, but no later than one (1) hour prior to the deadline for submitting Schedules to the CAISO in accordance with the CAISO rules for participation in the Real-Time Market. If the Available Capacity changes by at least one (1) MW as of a time that is less than one (1) hour prior to the Real-Time Market deadline, but before such deadline, then Seller must likewise notify Buyer. Such Notices shall contain information regarding the beginning date and time of the event resulting in the change in Available Capacity, the expected end date and time of such event, the expected Available Capacity in MW, and any other information required by the CAISO or reasonably requested by Buyer. With respect to any Forced Outage, Seller shall use commercially reasonable efforts to notify Buyer of such outage within ten (10) minutes of the commencement of the Forced Outage. Seller shall inform Buyer of any developments that will affect either the duration of such event or the availability of the Project during or after the end of such event. These notices and changes to Available Capacity shall be communicated in a method acceptable to Buyer; provided that Buyer specifies the method no later than 60 days prior to the effective date of such requirement. In the event Buyer fails to provide Notice of an acceptable method for communications under this Section 3.4[(b)][(c)][(iii)(D)], then Seller shall send such communications by telephone to Buyer's Real-Time Desk and shall be sent to Buyer's internet site as set forth in Appendix VI.

(E) To the extent that Seller obtains, in the normal course of business, other forecasts of energy production at the Project not otherwise specified in this Section 3.4, then Seller shall grant Buyer read-only access to such forecasts.

(iv) Replacement of Scheduling Coordinator.

(A) At least ninety (90) days prior to the end of the Delivery Term, or as soon as practicable before the date of any termination of this Agreement prior to the end of the Delivery Term, Seller shall take all actions necessary to terminate the designation of Buyer or the Third-Party SC, as applicable, as Seller's SC. These actions include (I) submitting to the CAISO a designation of a new SC for Seller to replace Buyer or the Third-Party SC (as applicable); (II) causing the newly-designated SC to submit a letter to the CAISO accepting the designation; and (III) informing Buyer and the Third-Party SC (if applicable) of the last date on which Buyer or the Third-Party SC (as applicable) will be Seller's SC.

(B) Buyer shall submit, or if applicable cause the Third-Party SC to submit, a letter to the CAISO identifying the date on which Buyer (or Third-Party SC, as applicable) resigns as Seller's SC on the first to occur of either (I) thirty (30) days prior to the end of the Delivery Term or (II) the date of any early termination of this Agreement.

3.5 Standards of Care.

(a) General Operation. Seller shall comply with all applicable requirements of Law, the CAISO, NERC and WECC relating to the Project (including those related to construction, safety, ownership and/or operation of the Project). In the event Seller requires any data or information from Buyer in order to comply with any applicable requirements of Law, including the requirements of CAISO, NERC and WECC, relating to the Project (including those related to construction, safety, ownership and/or operation of the Project), then Seller shall request in writing such data from Buyer no less than forty-five (45) calendar days prior to Seller's requested date of Buyer's response; provided that if Seller has less than forty-five (45) calendar days prior notice of the need for such data, Seller shall request in writing such data from Buyer as soon as reasonably practicable. Buyer shall make a good faith

effort to provide such data and/or information within the timeframe specified in writing by Seller or as soon thereafter as reasonably practicable.

(b) CAISO and WECC Standards. Each Party shall perform all generation, scheduling and transmission services in compliance with all applicable (i) operating policies, criteria, rules, guidelines, tariffs and protocols of the CAISO, (ii) WECC scheduling practices and (iii) Good Utility Practices.

(c) Reliability Standard. Seller agrees to abide by (i) CPUC General Order No. 167, “Enforcement of Maintenance and Operation Standards for Electric Generating Facilities”, and (ii) all applicable requirements regarding interconnection of the Project, including the requirements of the interconnected Participating Transmission Owner.

3.6 Metering. All output from the Project must be delivered through a single CAISO revenue meter located on the high-voltage side of the Project’s final step-up transformer (which must be dedicated solely to the Project) nearest to the Interconnection Point that exclusively measures output for the Project described herein. All Delivered Energy purchased under this Agreement must be measured by the Project’s CAISO revenue meter to be eligible for payment under this Agreement. Seller shall bear all costs relating to all metering equipment installed to accommodate the Project. In addition, Seller hereby agrees to provide all meter data to Buyer in a form acceptable to Buyer, and consents to Buyer obtaining from the CAISO the CAISO meter data applicable to the Project and all inspection, testing and calibration data and reports. Seller shall grant Buyer the right to retrieve the meter reads from the CAISO Operational Meter Analysis and Reporting (OMAR) web and/or directly from the CAISO meter(s) at the Project site. If the CAISO makes any adjustment to any CAISO meter data for a given time period, Seller agrees that it shall submit revised monthly invoices, pursuant to Section 6.2, covering the entire applicable time period in order to conform fully such adjustments to the meter data. Seller shall submit any such revised invoice no later than thirty (30) days from the date on which the CAISO provides to Seller such binding adjustment to the meter data.

3.7 Outage Notification.

(a) CAISO Approval of Outage(s). Buyer, in its capacity as Scheduling Coordinator, is responsible for securing CAISO approvals for Project outages, including securing changes in its outage schedules when CAISO disapproves Buyer’s schedules or cancels previously approved outages and for entering Project outages in the Scheduling and Logging system for the CAISO (“SLIC”) or successor system. As Scheduling Coordinator, Buyer shall put forth commercially reasonable efforts to secure and communicate CAISO approvals for Project outages in a timely manner to Seller.

(b) Planned Outages. During the Delivery Term, Seller shall notify Buyer of its proposed Planned Outage schedule for the Project for the following calendar year by complying with [Section 3.4[(b)][(c)][(iii)(A), (“Annual Forecast of Available Capacity”) and Section 3.4[(b)][(c)][(iii)(B), (Monthly Forecast of Available Capacity”)] [*Applies to intermittent facilities only*] [3.4[(b)][(c)][(iii)(A), (“Annual Forecast of Available Capacity”) and Section 3.4[(b)][(c)][(iii)(B), (Monthly Forecast of Available Capacity”)] [*Applies to all facilities other than intermittent facilities*] and implementing the notification procedures set forth in Appendix VI no later than July 1st of each year during the Delivery Term. Seller shall also notify Buyer of the proposed Planned Outage schedule for the Project by the earlier of ninety (90) days before the beginning of each month or forty-five (45) days before Buyer’s monthly Resource Adequacy capacity showing must be completed in accordance with the CAISO Tariff or decision of the CPUC. The Planned Outage schedule is subject to Buyer’s approval, which approval may not be unreasonably withheld or conditioned. Seller shall also confirm or provide updates to Buyer regarding the Planned Outage by the earlier of fourteen (14) days prior to each Planned Outage or two (2)

Business Days prior to the CAISO deadline for submitting Planned Outages. Seller shall not conduct Planned Outages during the months of January, May through September, and December. During all other months, Seller shall not schedule Planned Outages without the prior written consent of Buyer, which consent may not be unreasonably withheld or conditioned. Seller shall contact Buyer with any requested changes to the Planned Outage schedule if Seller believes the Project must be shut down to conduct maintenance that cannot be delayed until the next scheduled Planned Outage consistent with Good Utility Practices. Seller shall not change its Planned Outage schedule without Buyer's approval, not to be unreasonably withheld or conditioned. Subject to Section 3.7(a), after any Planned Outage has been scheduled, at any time up to the commencement of work for the Planned Outage, Buyer may direct that Seller change its outage schedule as ordered by CAISO. For non-CAISO ordered changes to a Planned Outage schedule requested by Buyer, Seller shall notify Buyer of any incremental costs associated with such schedule change and an alternative schedule change, if any, that would entail lower incremental costs. If Buyer agrees to pay the incremental costs, Seller shall use commercially reasonable efforts to accommodate Buyer's request.

(c) Forced Outages. Seller shall notify Buyer of a Forced Outage as promptly as possible, but no later than ten (10) minutes after the commencement of the Forced Outage and in accordance with the notification procedures set forth in Appendix VI. Buyer shall put forth commercially reasonable efforts to submit such outages to CAISO.

(d) Prolonged Outages. Seller shall notify Buyer of a Prolonged Outage as soon as practicable in accordance with the notification provisions in Appendix VI. Seller shall notify Buyer in writing when the Project is again capable of meeting its Contract Quantity on a *pro rata* basis also in accordance with the notification provisions in Appendix VI.

(e) Force Majeure. Within two (2) Business Days of commencement of an event of Force Majeure, the non-performing Party shall provide the other Party with oral notice of the event of Force Majeure, and within two (2) weeks of the commencement of an event of Force Majeure the non-performing Party shall provide the other Party with Notice in the form of a letter describing in detail the particulars of the occurrence giving rise to the Force Majeure claim. Failure to provide timely Notice constitutes a waiver of a Force Majeure claim. The suspension of performance due to a claim of Force Majeure must be of no greater scope and of no longer duration than is required by the Force Majeure. Buyer shall not be required to make any payments for any Products that Seller fails to deliver or provide as a result of Force Majeure during the term of a Force Majeure.

(f) Communications with CAISO. Buyer shall be responsible for all outage coordination communications with CAISO outage coordination personnel and CAISO operations management, including submission to CAISO of updates of outage plans, submission of clearance requests, and all other outage-related communications.

(g) Changes to Operating Procedures. Notwithstanding any language to the contrary contained in Sections 3.4, 3.6, 3.7, 3.8, or 10.13, or Appendix VI, and consistent with Section 3.5, Seller understands and acknowledges that the specified access to data and installation and maintenance of weather stations, transmission and scheduling mechanisms, metering requirements, Outage Notification Procedures and scheduling, forecast, bidding, notification and operating procedures described in the above-referenced sections are subject to change. If such changes are provided by (i) Notice from Buyer, then Seller shall implement any such changes as reasonably deemed necessary by Buyer; provided that such change does not result in an increased cost of performance to Seller hereunder other than *de minimis* amounts, or (ii) Law, then the Parties shall implement such changes as necessary for Seller and Buyer to perform their respective rights and obligations in accordance with the Law.

3.8 Operations Logs and Access Rights.

(a) Operations Logs. Seller shall maintain a complete and accurate log of all material operations and maintenance information on a daily basis. Such log shall include information on power production, [fuel consumption,]*[Bracketed language for applicable Baseload Product only]* efficiency, availability, maintenance performed, outages, results of inspections, manufacturer recommended services, replacements, electrical characteristics of the generators, control settings or adjustments of equipment and protective devices. Seller shall provide this information electronically to Buyer within thirty (30) days of Buyer's request.

(b) Access Rights. Buyer, its authorized agents, employees and inspectors may, on reasonable advance notice (which no case shall be less than three (3) Business Days) visit the Project during normal business hours for purposes reasonably connected with this Agreement or the exercise of any and all rights secured to Buyer by Law, or its tariff schedules, PG&E Interconnection Handbook, Electric Rule 21, and rules on file with the CPUC. In connection with the foregoing, Buyer, its authorized agents, employees and inspectors must (i) at all times adhere to all safety and security procedures as may be required by Seller; (ii) not interfere with the operation of the Project; and (iii) unless waived in writing by Seller, be escorted by a representative of Seller. Buyer shall make reasonable efforts to coordinate its emergency activities with the Safety and Security Departments, if any, of the Project operator. Seller shall keep Buyer advised of current procedures for contacting the Project operator's Safety and Security Departments.

3.9 New Generation Facility.

(a) Seller, at no cost to Buyer, shall be responsible to:

(i) Design and construct the Project.

(ii) Perform all studies, pay all fees, obtain all necessary approvals and execute all necessary agreements with the CAISO, the Participating Transmission Owner, and the applicable distribution provider for the Interconnection Facilities to Schedule and deliver the Product.

(iii) Acquire all permits and other approvals necessary for the construction, operation, and maintenance of the Project.

(iv) Complete all environmental impact studies necessary for the construction, operation, and maintenance of the Project.

(v) At Buyer's request, provide to Buyer the Seller's electrical specifications and design drawings pertaining to the Project for Buyer's review prior to finalizing design of the Project and before beginning construction work based on such specifications and drawings. Seller shall provide to Buyer reasonable advance Notice of any changes in the Project and provide to Buyer specifications and design drawings of any such changes.

(vi) Seller shall Notify Buyer of the Construction Start Date by sending to Buyer a written Certification substantially in the form provided in Appendix IV-1 as soon as practical upon issuance of Notice to Proceed.

(vii) Within fifteen (15) days after the close of each quarter from the first quarter following the Execution Date, until the month in which the Construction Start Date has occurred, provide to Buyer a quarterly Progress Report and agree to regularly scheduled meetings between

representatives of Buyer and Seller to review such quarterly reports and discuss Seller's construction progress. The quarterly Progress Report shall indicate whether Seller is on target to meet the Guaranteed Commercial Operation Date.

(viii) Within fifteen (15) days after the close of each month following the Construction Start Date until the Commercial Operation Date, provide to Buyer a monthly Progress Report and agree to regularly scheduled meetings between representatives of Buyer and Seller to review such monthly reports and discuss Seller's construction progress. The monthly Progress Report shall indicate whether Seller is on target to meet the Guaranteed Commercial Operation Date.

[The following Section 3.9(a)(ix) applies to geothermal Projects only]

[(ix) Provide to Buyer copies of all Geothermal Reservoir Reports and any revisions thereto, for the time period beginning on the Effective Date and ending on the last day of the first Contract Year.]

(b) Buyer shall have the right, but not the obligation, to:

(i) Notify Seller in writing of the results of the review performed pursuant to Section 3.9(a)(v) within thirty (30) days of Buyer's receipt of all specifications for the Project, including a description of any flaws perceived by Buyer in the design.

(ii) Inspect the Project's construction site or on-site Seller data and information pertaining to the Project during business hours upon reasonable notice.

(c) Guaranteed Commercial Operation Date.

(i) The Parties agree time is of the essence in regards to the Agreement. As such, Seller shall have demonstrated Commercial Operation per the terms of Appendix IV-2 by the date that is no later than twenty-four (24) months after the Effective Date of this Agreement, except as such date may be extended on a day for day basis for not more than a cumulative six (6) month period for a Permitted Extension (the "Guaranteed Commercial Operation Date").

(ii) Permitted Extensions. The Permitted Extensions to the Guaranteed Commercial Operation Date are as follows:

(A) Permitting Delay. The Guaranteed Commercial Operation Date may be extended on a day for day basis for not more than six (6) months if Seller has used commercially reasonable efforts (including Seller's timely filing of required documents and payment of all applicable fees) to obtain permits necessary for the construction and operation of the Project, but is unable to obtain such permits and Seller has worked diligently to resolve the delay ("Permitting Delay");

(B) Transmission Delay. The Guaranteed Commercial Operation Date may be extended on a day for day basis for a cumulative period equal to no more than six (6) months if Seller has used commercially reasonable efforts (including compliance with all CAISO, PTO, FERC or other requirements, as applicable, and Seller's timely submission of all required documents and applicable fees) to have the Project physically interconnected to the CAISO Grid and to complete all Electric System Upgrades, if any, but such interconnection or Electric System Upgrades cannot be completed by the Guaranteed Commercial Operation Date, and such delay is not caused by Seller, and Seller has worked diligently to resolve the delay ("Transmission Delay");

(C) Force Majeure Extension. The Guaranteed Commercial Operation Date may be extended on a day for day basis in the event of Force Majeure (“Force Majeure Extension”); provided that Seller works diligently to resolve the effect of the Force Majeure and provides evidence of its efforts promptly to Buyer upon Buyer’s written request; provided further that Seller may not claim Force Majeure for any reason that was the basis for or would qualify as a Permitting Delay or a Transmission Delay.

(iii) Notwithstanding the foregoing, if Seller claims more than one Permitted Extension under Section 3.9(c)(ii), such extensions cannot cumulatively exceed six (6) months and all Permitted Extensions taken shall be concurrent, rather than cumulative, during any overlapping days.

(iv) Notice of Permitted Extension.

(A) In order to request a Permitting Delay or Transmission Delay (individually and collectively, “Delay”), Seller shall provide Buyer with Notice of the requested Delay no later than sixty (60) days prior to the Guaranteed Commercial Operation Date, which Notice must clearly identify the Delay being requested, the length of the Delay requested (up to six (6) months), and include information necessary for Buyer to verify the length and qualification of the Delay. Buyer shall use reasonable discretion to grant or deny the requested extension, and shall provide Seller Notice of its decision within a reasonable time.

(B) In the case of a Force Majeure Extension, if sixty (60) days prior Notice is impracticable or impossible, Seller shall provide Notice as soon as possible after the occurrence of the Force Majeure event.

(v) Failure to Meet Guaranteed Commercial Operation Date. Seller shall cause the Project to achieve the Commercial Operation Date by the Guaranteed Commercial Operation Date; provided, however, that the Commercial Operation Date shall not occur more than one hundred eighty (180) days prior to the Guaranteed Commercial Operation Date. If the Commercial Operation Date occurs after the Guaranteed Commercial Operation Date after giving effect to Permitted Extensions or Force Majeure, then Buyer shall be entitled to declare an Event of Default and collect a Termination Payment pursuant to Article Five.

[The following subsections (d) and (e) shall only apply to a New Project:]

[(d) Resize of Project Due to Permit Failure.

(i) If Seller has not received or obtained by the earlier of the Expected Construction Start Date and the date that is six (6) months after the Effective Date final and non-appealable Governmental Approvals required for the construction of the Project with the Contract Capacity set forth in the Cover Sheet, after using commercially reasonable efforts to do so (including timely filings with all applicable Governmental Authorities and timely payment of any required fees) (“Permit Failure”), Seller may make a Contract Capacity Commitment on the Expected Construction Start Date (as may be extended), equal to, at a minimum, seventy percent (70%) of the Contract Capacity set forth in the Cover Sheet, provided that such amount shall also be the maximum amount of the generation capacity permitted under the final and non-appealable Governmental Approvals that Seller has received as of the Expected Construction Start Date (as may be extended), and may not be under one (1) MW, and provided further that for a period of two (2) years from any such resizing pursuant to this Section 3.9(d), Seller must offer Buyer a Right of First Offer for any Products from the Project up to the Contract Capacity set forth in the Cover Sheet as further provided in Section 3.9(e), below. Seller shall provide

Notice of such Contract Capacity Commitment to Buyer no later than ten (10) Business Days following the Expected Construction Start Date.

(ii) In the event that the Contract Capacity is reduced pursuant to Section 3.9(d)(i) above, the Contract Quantity during each Contract Year set forth in the Delivery Term Contract Schedule in the Cover Sheet shall be adjusted proportionately with such reduction.

(iii) In the event that the Contract Capacity and Contract Quantity are reduced pursuant to Sections 3.9(d)(i) and (ii), the revised Contract Capacity and Contract Quantity shall be used to determine Seller's performance under the Agreement, including the amount of Guaranteed Energy Production under Section 3.1(e) and the amount of Delivery Term Security or Term Security required under Section 8.4.

(iv) If the final Contract Capacity is less than the initial Contract Capacity due to a resize of the Project pursuant to Sections 3.1(e)(ii) and 3.9(d)(i), then Seller shall forfeit a proportional share of the Project Development Security on a percent-for-percent basis.

(e) Right of First Offer.

(i) If Seller resizes the Project due to Permit Failure, then for a period of three (3) years from the date on which Seller Notifies Buyer of the Contract Capacity Commitment ("Exclusivity Period"), neither Seller, its successors and assigns, nor its Affiliates shall enter into an obligation or agreement to sell or otherwise transfer any Products from the Project in excess of the Contract Capacity Commitment, up to the Contract Capacity set forth in the Cover Sheet, to any third party, unless Seller first offers, in writing, to sell to Buyer such Products from the Project on the same terms and conditions as this Agreement, subject to permitted modifications identified in subpart (ii) below, (the "First Offer") and Buyer either accepts or rejects such First Offer in accordance with the provisions herein.

(ii) If Buyer accepts the First Offer, Buyer shall Notify Seller within thirty (30) days of receipt of the First Offer subject to Buyer's management approval and CPUC Approval ("Buyer's Notice of First Offer Acceptance"), and then the Parties shall have not more than ninety (90) days from the date of Buyer's Notice to enter into a new power purchase agreement, in substantially the same form as this Agreement, or amend this Agreement, subject to CPUC Approval, if necessary; provided that the Contract Price may only be increased to reflect Seller's documented incremental costs in overcoming the Permit Failure.

(iii) If Buyer rejects or fails to accept Seller's First Offer within thirty (30) days of receipt of such offer, Seller shall thereafter be free to sell or otherwise transfer, and to enter into agreements to sell or otherwise transfer, any Products from the Project to any third party, so long as the material terms and conditions of such sale or transfer are not more favorable to the third party than those of the First Offer to Buyer. If, during the Exclusivity Period, Seller desires to enter into an obligation or agreement with a third party, Seller shall deliver to Buyer a certificate of an authorized officer of Seller (A) summarizing the material terms and conditions of such agreement and (B) certifying that the proposed agreement with the third party will not provide Seller with a lower rate of return than that offered in the First Offer to Buyer. If Seller is unable to deliver such a certificate to Buyer, then Seller may not sell or otherwise transfer, or enter into an agreement to sell or otherwise transfer, the Products from the Project without first offering to sell or otherwise transfer such Products to Buyer on such more favorable terms and conditions (the "Revised Offer") in accordance with subpart (ii) above. If within thirty (30) days of receipt of Seller's Revised Offer the Buyer rejects, or fails to accept by Notice to Seller, the Revised Offer, then Seller will thereafter be free to sell or otherwise transfer, and to enter into

agreements to sell or otherwise transfer, such Products from the Project to any third party on such terms and conditions as set forth in the certificate.]

(f) Excess Network Upgrade Cost Termination Right.

(i) Buyer has the right to terminate this Agreement by Notice on or before the date that is sixty (60) days after Seller provides to Buyer the results of any Interconnection Study, or the GIA tendered to Seller by the Participating Transmission Owner, if such Interconnection Study or GIA as of the date of the termination Notice, estimates, includes, specifies or reflects that the maximum total cost of the Network Upgrades to Buyer, or any Participating Transmission Owner under the jurisdiction of the CAISO, including costs reimbursed to Seller by Buyer or any Participating Transmission Owner under the jurisdiction of the CAISO (“Aggregate Network Upgrade Costs”), may in the aggregate exceed one hundred and ten percent (110%) of the amount identified in the Interconnection Studies that were submitted with Seller’s original bid offer (package) so long as the exceeded dollar amount is equal to or greater than one hundred thousand dollars (\$100,000.00) (“Network Upgrades Cap”), and Seller has not agreed to assume financial responsibility for Excess Network Upgrade Costs. This termination right is irrespective of any subsequent amendments of such Interconnection Study or GIA or any contingencies or assumptions upon which such Interconnection Study or GIA is based. Buyer’s Notice to terminate will be effective five (5) Business Days after such Notice is given to Seller.

(ii) Notwithstanding anything to the contrary in this Section 3.9(f)(ii), Buyer shall have no right to terminate this Agreement under Section 3.9(f)(i), if (A) Seller concurrently with its provision of the relevant Interconnection Study or GIA, as applicable, pursuant to Section 3.1(h)(ii)(B), irrevocably agrees to pay to the Participating Transmission Owner the amount by which the Aggregate Network Upgrade Costs exceed the Network Upgrades Cap (“Excess Network Upgrade Cost”) and (B) Seller enters into a GIA that states that Seller must pay all Excess Network Upgrade Costs without reimbursement from the Participating Transmission Owner. For sake of certainty, if Seller agrees to the above-described payment for the Excess Network Upgrade Costs pursuant to this Section 3.9(f)(ii), such agreement shall not independently convey to Seller any interest in or rights or title to any Network Upgrades or Congestion Revenue Rights (as defined in the CAISO Tariff) in connection with the development of the Project or the delivery of Product to Buyer pursuant to this Agreement.

(iii) Buyer shall have the right to terminate this Agreement on Notice, which will be effective five (5) Business Days after such Notice is given, (A) if Seller elects to exercise its right to pay for any Excess Network Upgrade Costs, but (B) FERC, CAISO, or any Participating Transmission Owner, as applicable, rejects Seller’s interconnection agreement, in whole or in part, or modifies Seller’s interconnection agreement in a manner that would make Seller unable to comply with Seller’s obligation pursuant to Section 3.9(f)(i). In order to be effective, Buyer’s Notice of termination must be given on or before the date that is ninety (90) days after such rejection or modification by FERC, CAISO, or any Participating Transmission Owner.

ARTICLE FOUR: COMPENSATION; MONTHLY PAYMENTS

4.1 Price.

(a) Contract Price. The Contract Price for each MWh of Product as measured by Delivered Energy in each Contract Year is set forth in Section C of the Cover Sheet.

For the avoidance of doubt, Seller shall not be compensated for any Surplus Delivered Energy.

(b) Test Period Payments. During the Test Period, Seller’s full compensation for Product sold to Buyer shall be the CAISO Revenues for the Delivered Energy, which revenues Buyer shall forward to Seller in accordance with the schedule described in Section 6.1.

4.2 TOD Periods. The time of delivery periods (“TOD Periods”) specified below shall be referenced by the following designations:

	TOD PERIOD		
Monthly Period	1. Peak	2. Shoulder	3. Night
A. July – Sept.	A1	A2	A3
B. Oct. – Mar.	B1	B2	B3
C. Apr. – June	C1	C2	C3

Monthly Period Definitions. The Monthly Periods are defined as follows:

- A. July – September;
- B. October – March; and
- C. April – June.

TOD Period Definitions. The TOD Periods are defined as follows:

- 1. **Peak** = hours ending 16 - 21 (Pacific Prevailing Time (PPT)) all days in the applicable Monthly Period.
- 2. **Shoulder** = hours ending 7 - 15 PPT all days in the applicable Monthly Period.
- 3. **Night** = hours ending 1 - 6, 22, 23 and 24 PPT all days in the applicable Monthly Period.

[Section 4.3 “Capacity Factor” below applies to Baseload Product only]

[4.3 Capacity Factor. The Capacity Factor shall be calculated by TOD Period and defined as the percentage amount resulting from Delivered Energy plus Deemed Delivered Energy, if any, in the applicable TOD Period divided by the product resulting from multiplying the Contract Capacity times the number of hours in the applicable TOD Period minus Seller Excuse Hours in the applicable TOD Period (“Capacity Factor”):

Capacity Factor = (Delivered Energy + Deemed Delivered Energy) / (Contract Capacity × (Hours in TOD Period minus Seller Excuse Hours)).]

4.4 TOD Factors and Monthly TOD Payment.

(a) TOD Factors. In accordance with all other terms of this Article Four, the Contract Price for Delivered Energy and Deemed Delivered Energy shall be adjusted by the following Time of Delivery Factors (“TOD Factors”) for each of the specified TOD Periods in which Delivered Energy or Deemed Delivered Energy is delivered:

RPS TOD FACTORS – Full Capacity Deliverability Status			
Period	1. Peak	2. Shoulder	3. Night
A. July – Sept.	2.2304	0.8067	0.9569
B. Oct – Mar.	1.1982	0.7741	0.9399
C. Apr. – June	1.1941	0.6585	0.9299

RPS TOD FACTORS – Energy Only Status			
Period	1. Peak	2. Shoulder	3. Night
A. July – Sept.	1.4514	0.8317	1.0144
B. Oct – Mar.	1.2855	0.8312	1.0092
C. Apr. – June	1.1327	0.7036	0.9977

(b) Monthly TOD Payment. *[The following bracketed clause is applicable to As Available products only]* [(Except as provided in Section 4.5,)] For each month in each Contract Year, Buyer shall pay Seller for Delivered Energy and Deemed Delivered Energy in each TOD Period (“Monthly TOD Payment”) the amount resulting from (i) multiplying the Contract Price times the TOD Factor for the applicable TOD Period, times the sum of Delivered Energy (exclusive of Surplus Delivered Energy) for such TOD Period plus (ii) for each hour in the TOD Period, the Deemed Delivered Energy Price applicable to that hour times the TOD Factor for the applicable TOD Period, times the amount of Deemed Delivered Energy for such hour:

$$\text{Monthly TOD Payment} = \sum_{\text{hour}=1}^n ([\text{Contract Price } \$] \times \text{TOD Factor} \times \text{Delivered Energy MWh}_{\text{hour}}) + ([\text{Deemed Delivered Energy Price}_{\text{hour}} \$] \times \text{TOD Factor} \times \text{Deemed Delivered Energy MWh}_{\text{hour}})$$

For the avoidance of doubt, *[The following bracketed clause is applicable to As-Available products only]* [Excess Energy shall be compensated as set forth in Section 4.5 and shall not be included in the determination of payment set forth above; and] “Delivered Energy” as used in the formula above excludes Surplus Delivered Energy, for which Seller will receive no compensation,

(c) Annual TOD Payment Adjustment. *[“Annual TOD Payment Adjustment” below applies to Baseload Products only.]* In any Contract Year, if the sum of the Monthly TOD Payments (“Annual TOD Payment”) exceeds the product of (i) Delivered Energy (exclusive of Surplus Delivered Energy) and Deemed Delivered Energy in such Contract Year multiplied by (ii) one hundred and five percent (105%) of the Contract Price (“Annual Maximum TOD Payment”), Seller shall pay Buyer the Excess Payment Amount, as defined below within fifteen (15) days of receipt of Buyer’s invoice for such amounts; provided that if Seller fails to pay such amount Buyer may net the Excess Payment Amount from the next following payment that would be due from Buyer to Seller and all subsequent payments until Buyer has recouped the entire Excess Payment Amount.

If Annual TOD Payment > Annual Maximum TOD Payment, Seller refunds the amount resulting from subtracting the Annual TOD Payment from the Annual Maximum TOD Payment which amount shall be the “Excess Payment Amount.”

Where Annual TOD Payment = sum of Monthly TOD Payment for each month of the applicable Contract Year, and

Where Annual Maximum TOD Payment = ([Contract Price \$] × 1.05 × [Delivered Energy MWh_{hour} + Deemed Delivered Energy MWh_{hour}])

For the avoidance of doubt, “Delivered Energy” as used in the formula above excludes Surplus Delivered Energy.

(d) Applicability of Full Capacity Deliverability Status TOD Factors. This Section 4.4(d) only applies to Sellers that elected to be FCDS Sellers in the Cover Sheet. The Full Capacity Deliverability Status TOD Factors shall apply as of the first day of the month immediately following the date that is forty-five (45) calendar days from the Effective FCDS Date.

[Section 4.5 Excess Delivered Energy below applies to Full Buy-Sell transactions of As-Available Product only]

[4.5 Excess Delivered and Deemed Delivered Energy.

(a) Excess Energy Price. If, at any point in any Contract Year, the amount of Delivered Energy (exclusive of Surplus Delivered Energy) plus the amount of Deemed Delivered Energy exceeds one hundred fifteen percent (115%) of the annual Contract Quantity amount, then:

(i) each MWh of additional Delivered Energy during such Contract Year shall be deemed “Excess Delivered Energy” and each MWh of additional Deemed Delivered Energy during such Contract Year shall be deemed “Excess Deemed Delivered Energy” (Excess Delivered Energy and Excess Deemed Delivered Energy, cumulatively, “Excess Energy”) and

(ii) for the remainder of such Contract Year:

(A) for every MWh of Excess Delivered Energy, the price paid to Seller shall be the lesser of (I) or (II), where (I) is seventy-five percent (75%) of the Contract Price for such Contract Year times the TOD Factor for the applicable TOD Period and (II) is the hourly DA Price at the Delivery Point (the “Excess Delivered Energy Price”); and

(B) for every MWh of Excess Deemed Delivered Energy the price paid to Seller shall be the lesser of (I) and (II) where (I) is seventy-five percent (75%) of the Deemed Delivered Energy Price times the TOD Factor for the applicable TOD Period and (II) is the hourly DA Price at the Delivery Point (the “Excess Deemed Delivered Energy Price”).

Excess Delivered Energy Price_{hour} = the lesser of ([75% × Contract Price × TOD Factor] OR DA Price_{hour})

Excess Deemed Delivered Energy Price_{hour} = the lesser of ([75% × Deemed Delivered Energy Price_{hour} × TOD Factor] OR DA Price_{hour})

For the avoidance of doubt, Excess Energy shall not include any Surplus Delivered Energy.

(b) Monthly Payment for Excess Energy. Buyer shall pay Seller for Excess Energy in each hour (“Monthly Payment for Excess Energy”) the amount resulting from (i) multiplying the Excess Delivered Energy Price applicable to that hour times the Excess Delivered Energy for such hour plus (ii) the Excess Deemed Delivered Energy Price applicable to that hour times the amount of Excess Deemed Delivered Energy for such hour:

$$\text{Monthly Payment for Excess Energy} = \sum_{\text{hour}=1}^n (\text{Excess Delivered Energy Price}_{\text{hour}} \times \text{Excess Delivered Energy MWh}_{\text{hour}}) + (\text{Excess Deemed Delivered Energy Price}_{\text{hour}} \times \text{Excess Deemed Delivered Energy MWh}_{\text{hour}})]$$

4.6 CAISO Charges.

(a) Seller shall assume all liability and reimburse Buyer for any and all CAISO Penalties incurred by Buyer because of Seller's failure to perform any covenant or obligation set forth in this Agreement. Buyer shall assume all liability and reimburse Seller for any and all CAISO Penalties incurred by Seller as a result of Buyer's actions, including those resulting in a Buyer Curtailment Period.

(b) Buyer, as Scheduling Coordinator, shall (i) be responsible for all costs and charges assessed by the CAISO with respect to scheduling and Imbalance Energy, subject to Sections 4.6(a) and (c) and (ii) retain the credits and other payments received as a result of Energy from the Project delivered to the Integrated Forward Market or Real-Time Market, including revenues associated with CAISO dispatches. Seller and Buyer shall cooperate to minimize such charges and Uninstructed Imbalance Energy to the extent possible. Seller shall use commercially reasonable efforts to monitor imbalances and shall promptly notify Buyer as soon as possible after it becomes aware of any material imbalance that is occurring or has occurred. Such notification shall not alter Seller's and Buyer's respective responsibilities for payment for Imbalance Energy and costs and CAISO Penalties under this Agreement. Throughout the Delivery Term, Buyer shall be entitled to all Integrated Forward Market Load Uplift Obligation credits (as defined or required for MRTU under the CAISO Tariff) associated with the Energy generated from the Project.

(c) Forecasting Penalties.

(i) Subject to Force Majeure, in the event Seller does not in a given hour either (A) provide the access and information required in Section 3.1(l)(i); (B) comply with the installation, maintenance and repair requirements of Section 3.1(l)(iv); or (C) provide the forecast of Available Capacity required in Section 3.4[(b)][(c)](iii), and the sum of Energy Deviations for each of the Settlement Intervals in the given hour exceeded the Performance Tolerance Band defined below, then Seller will be responsible for Forecasting Penalties as set forth below.

(ii) The Performance Tolerance Band is three percent (3%) multiplied by Contract Capacity multiplied by one (1) hour.

(iii) Forecasting Penalties. The Forecasting Penalty shall be equal to the greater of (A) one hundred fifty percent (150%) of the Contract Price or (B) the absolute value of the Real-Time Price, in each case for each MWh of Energy Deviation outside the Performance Tolerance Band, or any portion thereof, in every hour for which Seller fails to meet the requirements in Section 4.6(c)(i). Settlement of Forecasting Penalties shall occur as set forth in Section 6.1 of this Agreement.

4.7 Additional Compensation.

(a) To the extent not otherwise provided for in this Agreement, in the event that Seller is compensated by a third party for any Products produced by the Project, including compensation for Resource Adequacy or Green Attributes, Seller shall remit all such compensation directly to Buyer; provided that for avoidance of doubt, nothing herein precludes Seller from retaining credits related to Electric System Upgrades contemplated in Section 3.1(h)(i).

(b) To the extent that during the Delivery Term Seller (at a nominal or no cost to Seller) is exempt from, reimbursed for or receives any refunds, credits or benefits from CAISO for congestion charges or Congestion Revenue Rights (as defined in the CAISO Tariff), whether due to any adjustments in Congestion Revenue Rights or any Locational Marginal Price (as defined in the CAISO Tariff), market adjustments, invoice adjustments, or any other hedging instruments associated with the Product (collectively, any such refunds, credits or benefits are referred to as “Reductions”), then, at Buyer’s option, either (i) Seller shall transfer any such Reductions and their related rights to Buyer less any costs incurred by Seller in connection with such Reductions; or (ii) Buyer shall reduce payments due to Seller under this Agreement in amounts equal to the Reductions less any costs incurred by Seller in connection with such Reduction and Seller shall retain the Reductions.

[Section 4.7(c) below applies to Baseload Product only]

(c) Reliability Must-Run Contract and Capacity Procurement Mechanism Obligations. Seller with an existing RMR Contract will assign all of the proceeds of any RMR Contract affecting the Project to Buyer, except as provided below. Buyer shall retain all revenues from said RMR Contract, except for Monthly Surcharge Payments, the CAISO Repair Share, and Motoring Charges for Ancillary Services Dispatch (“Retained Revenues”), as each is defined in the applicable RMR Contract, all of which shall be remitted to Seller. If the CAISO and/or Seller wish to negotiate or renegotiate an RMR Contract or contract related to the Capacity Procurement Mechanism (as defined in the CAISO Tariff) or similar capacity commitment under the CAISO Tariff that pertains to Unit(s) under this Agreement as of the Execution Date of this Agreement, Seller shall include Buyer in any such negotiations. If Seller enters into any new RMR Contract or contract related to the Capacity Procurement Mechanism or similar capacity commitment affecting the Project, Seller shall assign the revenues from such contract, except for Retained Revenues, Monthly Surcharge Payments, the CAISO Repair Share, and Motoring Charges for Ancillary Services Dispatch to Buyer.

ARTICLE FIVE: EVENTS OF DEFAULT; PERFORMANCE REQUIREMENT; REMEDIES

5.1 Events of Default. An “Event of Default” shall mean,

(a) with respect to a Party that is subject to the Event of Default, the occurrence of any of the following:

(i) the failure to make, when due, any payment required pursuant to this Agreement if such failure is not remedied within five (5) Business Days after written Notice is received by the Party failing to make such payment;

(ii) any representation or warranty made by such Party herein (A) is false or misleading in any material respect when made or (B) with respect to Section 10.2(b), becomes false or misleading in any material respect during the Delivery Term; provided that, if a change in Law occurs after the Execution Date that causes the representation and warranty made by Seller in Section 10.2(b) to be materially false or misleading, such breach of the representation or warranty in Section 10.2(b) shall not be an Event of Default if Seller has used commercially reasonable efforts to comply with such change in Law during the Delivery Term in order to make the representation and warranty no longer false or misleading;

(iii) the failure to perform any material covenant or obligation set forth in this Agreement (except to the extent constituting a separate Event of Default), if such failure is not remedied within forty-five (45) days after Notice from the Non-Defaulting Party, which time period shall be

extended if the Defaulting Party is making diligent efforts to cure such failure to perform, provided that such extended period shall not exceed forty-five (45) additional days;

(iv) such Party becomes Bankrupt; or

(v) such Party consolidates or amalgamates with, or merges with or into, or transfers all or substantially all of its assets to, another entity and, at the time of such consolidation, amalgamation, merger or transfer, the resulting, surviving or transferee entity fails to assume all the obligations of such Party under this Agreement to which it or its predecessor was a party by operation of Law or pursuant to an agreement reasonably satisfactory to the other Party.

(b) with respect to Seller as the Defaulting Party, the occurrence of any of the following:

(i) if at any time during the Term of this Agreement, Seller delivers or attempts to deliver to the Delivery Point for sale under this Agreement Energy that was not generated by the Project;

(ii) failure by Seller to meet the Guaranteed Commercial Operation Date, as extended by any Permitted Extensions due solely to Seller's inability to achieve, after the use of commercially reasonable efforts, by the Guaranteed Commercial Operation Date the permits necessary to construct or operate the Project, the physical interconnection of the Project to the CAISO or any necessary Electric System Upgrades;

(iii) failure by Seller for any reason other than those explicitly provided in Section 5.1(b)(ii) above and Section 11.1(a)(ii) to meet the Guaranteed Commercial Operation Date as may be extended by Permitted Extensions;

(iv) failure by Seller to satisfy the creditworthiness/collateral requirements agreed to pursuant to Sections 8.3, 8.4, or 8.5 of this Agreement and such failure is not cured within any applicable cure period;

(v) if Seller has provided and Buyer has accepted, a Guaranty to satisfy the collateral obligations under this Agreement, then with respect to such guarantor or the Guaranty, if Seller had not replaced the Guaranty in accordance with Section 8.6 within five (5) Business Days following Buyer's Notice of a request for replacement;

(vi) failure by Seller to achieve the Guaranteed Energy Production requirement as set forth in Section 3.1(e)(ii) of this Agreement as follows:

(A) after the one (1) year GEP Cure period Seller has failed to cure the GEP Failure and has failed to pay GEP Damages in the time period set forth in Section 3.1(e)(ii); or

(B) if, after any Performance Measurement Period the cumulative GEP Shortfall for all preceding Performance Measurement Periods occurring during the Delivery Term equals or exceeds two times the Contract Quantity (as may be adjusted pursuant to Sections 3.9(d) and 3.1(e)(ii)); provided, however, that if all or a portion of the GEP Shortfall during an applicable Performance Measurement Period is principally caused by a non-Force Majeure major equipment malfunction, breakdown, or failure resulting in a reduction of Energy production of the Project by at least fifty percent (50%) of the Contract Quantity in one or both years of the Performance Measurement Period, as applicable, and such malfunction, breakdown, or failure was not caused by Seller and could not

have been avoided through the exercise of Good Utility Practice, such failure shall be excluded from the calculation of the cumulative GEP Shortfall for purposes of this subsection.

(vii) Seller has not obtained the deliverability type selected in Section A (FCDS or PCDS) of the Cover Sheet by the Deliverability Finding Deadline.

(viii) Seller has not obtained the Partial Capacity Deliverability Status Amount identified in Section A of the Cover Sheet by the Deliverability Finding Deadline.

5.2 Remedies. If an Event of Default with respect to a Defaulting Party shall have occurred and is continuing, the other Party (“Non-Defaulting Party”) shall have the following rights:

(a) send Notice, designating a day, no earlier than the day such Notice is deemed to be received and no later than twenty (20) days after such Notice is deemed to be received, as an early termination date of this Agreement (“Early Termination Date”) on which to (i) collect the Damage Payment (in the case of any Event of Default of Seller that arose at any time prior to the commencement of the Delivery Term, including an Event of Default of Seller pursuant to Section 5.1(b)(ii)), or (ii) collect the Termination Payment (in the case of any Event of Default of Seller that arose during the Delivery Term or in the case of any Event of Default of Buyer at any time);

(b) accelerate all amounts owing between the Parties, terminate the Transaction and end the Delivery Term effective as of the Early Termination Date;

(c) (i) collect the Damage Payment in accordance with Section 5.8 below, if the Event of Default arose under Section 5.1(b)(ii), or (ii) collect the Termination Payment for any other Event of Default;

(d) withhold any payments due to the Defaulting Party under this Agreement;

(e) suspend performance;

(f) exercise its rights pursuant to Section 8.3 to draw upon and retain Performance Assurance;

(g) demand payment for damages due to Buyer’s unexcused failure to take delivery or pay for Product; and

(h) exercise any other rights or remedies available at Law or in equity (including the collection of monetary damages) to the extent otherwise permitted under this Agreement.

Notwithstanding anything to the contrary contained herein, Seller may exercise the rights or remedies set forth in Sections 5.2(e), (g), and (h) without terminating this Agreement.

5.3 Calculation of Termination Payment.

(a) In the case where the Non-Defaulting Party is entitled to collect the Termination Payment pursuant to Section 5.2(a)(ii), the Non-Defaulting Party shall calculate, in a commercially reasonable manner, a Settlement Amount for the Terminated Transaction as of the Early Termination Date. Third parties supplying information for purposes of the calculation of Gains or Losses may include dealers in the relevant markets, end-users of the relevant product, information vendors and other sources of market information. If the Non-Defaulting Party uses the market price for a comparable transaction to

determine the Gains or Losses, such price should be determined by using the average of market quotations provided by three (3) or more bona fide unaffiliated market participants. If the number of available quotes is three, then the average of the three quotes shall be deemed to be the market price. Where a quote is in the form of bid and ask prices, the price that is to be used in the averaging is the midpoint between the bid and ask price. The quotes shall be obtained in a commercially reasonable manner and shall be: (i) for a like amount, (ii) of the same Product, (iii) at the same Delivery Point, and (iv) for the remaining Delivery Term. Regardless of the method chosen by the Non-Defaulting Party to calculate the Settlement Amount, the Settlement Amount must still be reasonable under the circumstances.

(b) If the Non-Defaulting Party's aggregate Gains exceed its aggregate Losses and Costs, if any, resulting from the termination of the Terminated Transaction, the Settlement Amount shall be zero.

(c) The Non-Defaulting Party shall not have to enter into replacement transactions to establish a Settlement Amount.

5.4 Notice of Payment of Termination Payment. As soon as practicable after a liquidation, Notice shall be given by the Non-Defaulting Party to the Defaulting Party of the amount of the Termination Payment and whether the Termination Payment is due to the Non-Defaulting Party. The Notice shall include a written statement explaining in reasonable detail the calculation of such amount and the sources for such calculation. The Termination Payment shall be made to the Non-Defaulting Party, as applicable, within ten (10) Business Days after such Notice is effective.

5.5 Disputes With Respect to Termination Payment. If the Defaulting Party disputes the Non-Defaulting Party's calculation of the Termination Payment, in whole or in part, the Defaulting Party shall, within ten (10) Business Days of receipt of the Non-Defaulting Party's calculation of the Termination Payment, provide to the Non-Defaulting Party a detailed written explanation of the basis for such dispute. Disputes regarding the Termination Payment shall be determined in accordance with Article Twelve.

5.6 Rights And Remedies Are Cumulative. The rights and remedies of a Party pursuant to this Article Five shall be cumulative and in addition to the rights of the Parties otherwise provided in this Agreement.

5.7 Duty to Mitigate. Buyer and Seller shall each have a duty to mitigate damages pursuant to this Agreement, and each shall use reasonable efforts to minimize any damages it may incur as a result of the other Party's non-performance of this Agreement, including with respect to termination of this Agreement.

5.8 Damage Payment for Failure to Achieve Guaranteed Dates. The Parties agree that the Damage Payment to be paid by Seller for an Event of Default arising under Section 5.1(b)(ii) associated with Seller's failure to achieve the Guaranteed Commercial Operation Date shall be considered liquidated damages and not a penalty, in accordance with Section 7.1.

ARTICLE SIX: PAYMENT

6.1 Billing and Payment; Remedies. On or about the tenth (10th) day of each month beginning with the second month of either the Test Period or the first Contract Year, whichever occurs first, and every month thereafter, and continuing through and including the first month following the end of the Delivery Term, Seller shall provide to Buyer (a) records of metered data, including CAISO

metering and transaction data sufficient to document and verify the generation of Product by the Project for any CAISO settlement time interval during the preceding months, (b) access to any records, including invoices or settlement data from the CAISO, necessary to verify the accuracy or amount of any Reductions; and (c) an invoice, in the format specified by Buyer, covering the services provided in the preceding month determined in accordance with the applicable provisions of Article Four. Seller shall continue to provide to Buyer an invoice of CAISO charges, net any sums Buyer owes Seller under this Agreement, on or about the tenth (10th) day of each month until the date of the Final True-Up. Buyer shall pay the undisputed amount of such invoices less the amount of any RA Deficiency Amount and the amount of any Forecasting Penalties, as applicable on or before the later of the twenty-fifth (25th) day of each month and fifteen (15) days after receipt of the invoice. If either the invoice date or payment date is not a Business Day, then such invoice or payment shall be provided on the next following Business Day. During the Test Period, and for twelve (12) months following the Test Period only, Buyer shall provide to Seller a statement of the CAISO Revenues and any true-ups of CAISO Revenues from prior months and Buyer shall forward to Seller the CAISO Revenues from such statement, according to the invoice and payment schedules described in this Section 6.1. Each Party will make payments by electronic funds transfer, or by other mutually agreeable method(s), to the account designated by the other Party. Any undisputed amounts not paid by the due date will be deemed delinquent and will accrue interest at the Interest Rate, such interest to be calculated from and including the due date to but excluding the date the delinquent amount is paid in full. Invoices may be sent by facsimile or e-mail.

6.2 Disputes and Adjustments of Invoices. In the event an invoice or portion thereof or any other claim or adjustment arising hereunder, is disputed, payment of the undisputed portion of the invoice shall be required to be made when due, with Notice of the objection given to the other Party. Any invoice dispute or invoice adjustment shall be in writing and shall state the basis for the dispute or adjustment. Payment of the disputed amount shall not be required until the dispute is resolved. Subject to Section 3.6, in the event adjustments to payments are required as a result of inaccurate meter(s), Buyer shall use corrected measurements to recompute the amount due from Buyer to Seller for the Product delivered under the Transaction during the period of inaccuracy. The Parties agree to use good faith efforts to resolve the dispute or identify the adjustment as soon as possible. Upon resolution of the dispute or calculation of the adjustment, any required payment shall be made within fifteen (15) days of such resolution along with interest accrued at the Interest Rate from and including the due date, but excluding the date paid. Inadvertent overpayments shall be returned upon request or deducted by the Party receiving such overpayment from subsequent payments, with interest accrued at the Interest Rate from and including the date of such overpayment, but excluding the date repaid or deducted by the Party receiving such overpayment. Any dispute with respect to an invoice is waived unless the other Party is notified in accordance with this Section 6.2 within twelve (12) months after the invoice is rendered or any specific adjustment to the invoice is made; provided that, such waiver shall not apply to any adjustment or dispute related to Seller's performance under any applicable RMR Contract; and provided further that, any disputes with respect to a statement of CAISO Revenues is waived unless Seller notifies Buyer in accordance with this Section 6.2 within one (1) month after the last statement of CAISO Revenues is provided. If an invoice is not rendered within twelve (12) months after the close of the month during which performance under the Transaction occurred, the right to payment for such performance is waived.

ARTICLE SEVEN: LIMITATIONS

7.1 Limitation of Remedies, Liability and Damages. EXCEPT AS MAY OTHERWISE BE EXPRESSLY PROVIDED IN THIS AGREEMENT, THERE IS NO WARRANTY OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE, AND ANY AND ALL IMPLIED WARRANTIES ARE DISCLAIMED. LIABILITY SHALL BE LIMITED TO DIRECT ACTUAL DAMAGES ONLY, SUCH DIRECT ACTUAL DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY

ARE WAIVED UNLESS EXPRESSLY HEREIN PROVIDED. NEITHER PARTY SHALL BE LIABLE FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES, BY STATUTE, IN TORT OR CONTRACT, UNDER ANY INDEMNITY PROVISION OR OTHERWISE. UNLESS EXPRESSLY HEREIN PROVIDED, AND SUBJECT TO THE PROVISIONS OF SECTION 10.5 ("INDEMNITIES"), IT IS THE INTENT OF THE PARTIES THAT THE LIMITATIONS HEREIN IMPOSED ON REMEDIES AND THE MEASURE OF DAMAGES BE WITHOUT REGARD TO THE CAUSE OR CAUSES RELATED THERETO, INCLUDING THE NEGLIGENCE OF ANY PARTY, WHETHER SUCH NEGLIGENCE BE SOLE, JOINT OR CONCURRENT, OR ACTIVE OR PASSIVE.

THE PARTIES CONFIRM THAT THE EXPRESS REMEDIES AND MEASURES OF DAMAGES PROVIDED IN THIS AGREEMENT SATISFY THE ESSENTIAL PURPOSES HEREOF.

TO THE EXTENT ANY DAMAGES REQUIRED TO BE PAID HEREUNDER ARE LIQUIDATED, THE PARTIES ACKNOWLEDGE THAT THE DAMAGES ARE DIFFICULT OR IMPOSSIBLE TO DETERMINE, OR OTHERWISE OBTAINING AN ADEQUATE REMEDY IS INCONVENIENT AND THE DAMAGES CALCULATED HEREUNDER CONSTITUTE A REASONABLE APPROXIMATION OF THE HARM OR LOSS.

ARTICLE EIGHT: CREDIT AND COLLATERAL REQUIREMENTS

8.1 Buyer Financial Information. If requested by Seller, Buyer shall deliver to Seller (a) within one hundred twenty (120) days after the end of each fiscal year with respect to Buyer, a copy of Buyers' annual report containing audited consolidated financial statements for such fiscal year and (b) within sixty (60) days after the end of each of Buyer's first three fiscal quarters of each fiscal year, a copy of Buyers' quarterly report containing unaudited consolidated financial statements for each accounting period prepared in accordance with Generally Accepted Accounting Principles. Buyer shall be deemed to have satisfied such delivery requirement if the applicable report is publicly available on Buyer's website or on the SEC EDGAR information retrieval system; provided however, that should such statements not be available on a timely basis due to a delay in preparation or certification, such delay shall not be an Event of Default, so long as such statements are provided to Seller upon their completion and filing with the SEC.

8.2 Seller Financial Information. If requested by Buyer, Seller shall deliver to Buyer (a) within one hundred twenty (120) days following the end of each fiscal year, a copy of Seller's or Seller's guarantor's, if applicable, annual report containing unaudited consolidated financial statements for such fiscal year (or audited consolidated financial statements for such fiscal year if otherwise available) and (b) within sixty (60) days after the end of each of its first three fiscal quarters of each fiscal year, a copy of such Party's quarterly report containing unaudited consolidated financial statements for such fiscal quarter. In all cases the statements shall be for the most recent accounting period and shall be prepared in accordance with Generally Accepted Accounting Principles; provided, however, that should any such statements not be available on a timely basis due to a delay in preparation or certification, such delay shall not be an Event of Default so long as such Party diligently pursues the preparation, certification and delivery of the statements.

[For purposes of Sections 8.3 and 8.4, existing ERRs to replace Project Development Security with Pre-Delivery Term Security]

8.3 Grant of Security Interest/Remedies. To secure its obligations under this Agreement and to the extent Seller delivers the Project Development Security, Delivery Term Security, or Term Security, as applicable, hereunder, Seller hereby grants to Buyer, as the secured party, a first priority security

interest in, and lien on (and right of setoff against), and assignment of, all such Performance Assurance posted with Buyer in the form of cash collateral and cash equivalent collateral and any and all proceeds resulting therefrom or the liquidation thereof, whether now or hereafter held by, on behalf of, or for the benefit of, Buyer. Within thirty (30) days of the delivery of the Project Development Security, Delivery Term Security, or Term Security, as applicable, Seller agrees to take such action as Buyer reasonably requires in order to perfect a first-priority security interest in, and lien on (and right of setoff against), such Performance Assurance and any and all proceeds resulting therefrom or from the liquidation thereof. Upon or any time after the occurrence or deemed occurrence and during the continuation of an Event of Default or an Early Termination Date, Buyer, as the Non-Defaulting Party, may do any one or more of the following: (a) exercise any of the rights and remedies of a secured party with respect to all Project Development Security, Delivery Term Security, or Term Security, as applicable, including any such rights and remedies under the Law then in effect; (b) exercise its rights of setoff against any and all property of Seller, as the Defaulting Party, in the possession of the Buyer or Buyer's agent; (c) draw on any outstanding Letter of Credit issued for its benefit; and (d) liquidate all Project Development Security, Delivery Term Security, or Term Security, as applicable, then held by or for the benefit of Buyer free from any claim or right of any nature whatsoever of Seller, including any equity or right of purchase or redemption by Seller. Buyer shall apply the proceeds of the collateral realized upon the exercise of any such rights or remedies to reduce Seller's obligations under the Agreement (Seller remaining liable for any amounts owing to Buyer after such application), subject to the Buyer's obligation to return any surplus proceeds remaining after such obligations are satisfied in full.

8.4 Performance Assurance.

(a) Security. Seller agrees to deliver to Buyer collateral to secure its obligations under this Agreement, which Seller shall maintain in full force and effect for the period posted with Buyer, as follows:

(i) Project Development Security pursuant to this Section 8.4(a)(i) in the amount of \$60/kW for As-Available resources or \$90/kW for Baseload resources multiplied by the capacity of the Project as reflected in Section B of the Cover Sheet, within five (5) Business Days following the Effective Date of this Agreement until Seller posts Delivery Term Security pursuant to Section 8.4(a)(ii) below with Buyer.

(ii) Delivery Term Security pursuant to this Section 8.4(a)(ii) in the amount of five percent (5%) of expected total Project revenues from the date required pursuant to Section 3.1(c)(i) as a condition precedent to the Initial Energy Delivery Date until the end of the Term; provided that, with Buyer's consent, Seller may elect to apply the Project Development Security posted pursuant to Section 8.4(a)(i) toward the Delivery Term Security posted pursuant to this Section 8.4(a)(ii).

[For purposes of Section 8.4(a), GTSR Projects 3 MWs or less only need to comply with the following bracketed language.]

[(iii) Term Security pursuant to this Section 8.4(a)(iii) in the amount of \$20/kW for GTSR Projects with Contract Capacity of three (3) MW and under multiplied by the capacity of the Project as reflected in Section B of the Cover Sheet, within thirty (30) days following the Effective Date of this Agreement until the end of the Term.]

The amount of Performance Assurance required under this Agreement shall not be deemed a limitation of damages. Except as specifically provided for in this Section 8.4(a), Buyer acknowledges that Seller shall not be required to post any additional security.

(b) Use of Project Development Security or Term Security. Buyer shall be entitled to draw upon the Project Development Security or Term Security for any damages arising upon Buyer's declaration of an Early Termination Date.

(c) Termination of Project Development Security. If after the Initial Energy Delivery Date no damages are due and owing to Buyer under this Agreement, then Seller shall no longer be required to maintain the Project Development Security, and Buyer shall return to Seller the Project Development Security, less the amounts drawn in accordance with Section 8.4(b). The Project Development Security (or portion thereof) due to Seller shall be returned to Seller within five (5) Business Days of Seller's provision of the Delivery Term Security, as applicable unless, with Buyer's consent, Seller elects to apply the Project Development Security posted pursuant to Section 8.4(a)(i) toward the Delivery Term Security posted pursuant to Section 8.4(a)(ii), as applicable. ***[Section 8.4(c) does not apply to GTSR Projects 3 MWs or less.]***

(d) Payment and Transfer of Interest. Buyer shall pay interest on cash held as Project Development Security, Delivery Term Security or Term Security, as applicable, at the Interest Rate; provided that, the interest on Project Development Security shall be retained by Buyer until Seller posts the Delivery Term Security pursuant to Section 8.4(a)(ii). Upon Seller's posting of the Delivery Term Security, all accrued interest on the unused portion of Project Development Security shall be transferred from Buyer to Seller in the form of cash by wire transfer to the bank account specified under "Wire Transfer" in the Cover Sheet (Notices List). After Seller posts the Delivery Term Security or Term Security, Buyer shall transfer (as described in the preceding sentence) on or before each Interest Payment Date the Interest Amount due to Seller for such Delivery Term Security or Term Security.

(e) Return of Performance Assurance. Buyer shall return the unused portion of Project Development Security, Delivery Term Security or Term Security, as applicable, including the payment of any interest due thereon, pursuant to Section 8.4(d) above, to Seller promptly after the following has occurred: (i) the Term of the Agreement has ended, or subject to Section 8.3, an Early Termination Date has occurred, as applicable; and (ii) all payment obligations of the Seller arising under this Agreement, including payments pursuant to Section 4.6 ("CAISO Charges"), Termination Payment, indemnification payments or other damages are paid in full (whether directly or indirectly such as through set-off or netting).

(f) Adjustment of Security Amounts for Project Resizing. The required amount of Delivery Term Security or Term Security, as applicable, shall be proportionally and automatically adjusted in connection with any resizing of the Project under Section 3.9(d), and Buyer shall promptly return to Seller the unused portion of Delivery Term Security or Term Security in connection with any such adjustment.

8.5 Letter of Credit. Performance Assurance provided in the form of a Letter of Credit shall be subject to the following provisions:

(a) If Seller has provided a Letter of Credit pursuant to any of the applicable provisions in this Article Eight, then Seller shall renew or cause the renewal of each outstanding Letter of Credit on a timely basis in accordance with this Agreement.

(b) In the event the issuer of such Letter of Credit at any time (i) fails to maintain the requirements of an Eligible LC Bank or Letter of Credit, (ii) indicates its intent not to renew such Letter of Credit, or (iii) fails to honor Buyer's properly documented request to draw on such Letter of Credit, Seller shall cure such occurrence by complying with either (A) or (B) below in an amount equal to the outstanding Letter of Credit, and by completing the action within five (5) Business Days after the date of

Buyer's Notice to Seller of an occurrence listed in this subsection (Seller's compliance with either (A) or (B) below is considered the "Cure"):

(A) providing a substitute Letter of Credit that is issued by an Eligible LC Bank, other than the bank which is the subject of Buyer's Notice to Seller in Section 8.5(b) above, or

(B) posting cash.

If Seller fails to Cure or if such Letter of Credit expires or terminates without a full draw thereon by Buyer, or fails or ceases to be in full force and effect at any time that such Letter of Credit is required pursuant to the terms of this Agreement, then Seller shall have failed to meet the creditworthiness or collateral requirements of Article Eight.

(c) Notwithstanding the foregoing in Section 8.5(b), if, at any time, the issuer of such Letter of Credit has a Credit Rating on "credit watch" negative or developing by S&P, or is on Moody's "watch list" under review for downgrade or uncertain ratings action (either a "Watch"), then Buyer may make a demand to Seller by Notice ("LC Notice") to provide a substitute Letter of Credit that is issued by an Eligible LC Bank, other than the bank on a Watch ("Substitute Letter of Credit"). The Parties shall have thirty (30) Business Days from the LC Notice to negotiate a Substitute Letter of Credit ("Substitute Bank Period").

(i) If the Parties do not agree to a Substitute Letter of Credit by the end of the Substitute Bank Period, then Buyer shall provide Seller with Notice within five (5) Business Days following the expiration of the Substitute Bank Period ("Ineligible LC Bank Notice Period") that either:

(A) Buyer agrees to continue accepting the then currently outstanding Letter of Credit from the bank that is the subject of the LC Notice, but such bank shall no longer be an Eligible LC Bank ("Ineligible LC Bank") and Buyer will not accept future or renewals of Letters of Credit from the Ineligible LC Bank; or

(B) the bank that is the subject of the LC Notice is an Ineligible LC Bank and Seller shall then have thirty (30) days from the date of Buyer's Notice to Cure pursuant to Section 8.5(b) and, if Seller fails to Cure, then the last paragraph in Section 8.5(b) shall apply to Seller.

(ii) If the Parties have not agreed to a Substitute Letter of Credit and Buyer fails to provide a Notice during the Ineligible LC Bank Notice Period above, then Seller may continue providing the Letter of Credit posted immediately prior to the LC Notice.

(d) In all cases, the reasonable costs and expenses of establishing, renewing, substituting, canceling, increasing, reducing, or otherwise administering the Letter of Credit shall be borne by Seller.

8.6 Guaranty. If at any time Seller's guarantor or Guaranty is no longer acceptable to Buyer in its sole discretion, Seller shall replace the Guaranty with Performance Assurance as provided herein. Within five (5) Business Days following Buyer's written request for replacement of the Guaranty, Seller shall deliver to Buyer replacement Performance Assurance in the form of a replacement Guaranty, Letter of Credit or cash in an amount equal to the applicable amount of the Guaranty issued pursuant to this Agreement. In the event Seller shall fail to provide replacement Performance Assurance to Buyer as required in the preceding sentence, then Buyer may declare an Event of Default pursuant to Section 5.1(b)(v) by providing Notice thereof to Seller in accordance with Section 5.2.

ARTICLE NINE: GOVERNMENTAL CHARGES

9.1 Cooperation. Each Party shall use reasonable efforts to implement the provisions of and to administer this Agreement in accordance with the intent of the Parties to minimize all taxes, so long as neither Party is materially adversely affected by such efforts.

9.2 Governmental Charges. Seller shall pay or cause to be paid all taxes imposed by any Governmental Authority ("Governmental Charges") on or with respect to the Product or the Transaction arising at the Delivery Point, including ad valorem taxes and other taxes attributable to the Project, land, land rights or interests in land for the Project. Buyer shall pay or cause to be paid all Governmental Charges on or with respect to the Product or the Transaction from the Delivery Point. In the event Seller is required by Law or regulation to remit or pay Governmental Charges which are Buyer's responsibility hereunder, Buyer shall promptly reimburse Seller for such Governmental Charges. If Buyer is required by Law or regulation to remit or pay Governmental Charges which are Seller's responsibility hereunder, Buyer may deduct such amounts from payments to Seller with respect to payments under the Agreement; if Buyer elects not to deduct such amounts from Seller's payments, Seller shall promptly reimburse Buyer for such amounts upon request. Nothing shall obligate or cause a Party to pay or be liable to pay any Governmental Charges for which it is exempt under the Law. A Party that is exempt at any time and for any reason from one or more Governmental Charges bears the risk that such exemption shall be lost or the benefit of such exemption reduced; and thus, in the event a Party's exemption is lost or reduced, each Party's responsibility with respect to such Governmental Charge shall be in accordance with the first four sentences of this Section.

ARTICLE TEN: MISCELLANEOUS

10.1 Recording. Unless a Party expressly objects to a recording at the beginning of a telephone conversation, each Party consents to the creation of a tape or electronic recording of all telephone conversations between Buyer's employees or representatives performing a Scheduling Coordinator function as provided in Section 3.4[(b)][(c)] and any representative of Seller. The Parties agree that any such recordings will be retained in confidence, secured from improper access, and may be submitted in evidence in any proceeding or action relating to this Agreement. Each Party waives any further notice of such monitoring or recording, and agrees to notify its officers and employees of such monitoring or recording and to obtain any necessary consent of such officers and employees.

10.2 Representations and Warranties.

(a) General Representations and Warranties. On the Execution Date, each Party represents and warrants to the other Party that:

(i) it is duly organized, validly existing and in good standing under the Laws of the jurisdiction of its formation;

(ii) it has all regulatory authorizations necessary for it to perform its obligations under this Agreement, except for (A) CPUC Approval in the case of Buyer, and (B) all permits necessary to install, operate and maintain the Project in the case of Seller;

(iii) it is a "forward contract merchant" within the meaning of the United States Bankruptcy Code (as in effect as of the Execution Date of this Agreement);

(iv) the execution, delivery and performance of this Agreement is within its powers, have been duly authorized by all necessary action and do not violate any of the terms and conditions in its governing documents, any contracts to which it is a party or any Laws applicable to it;

(v) this Agreement and each other document executed and delivered in accordance with this Agreement constitutes a legally valid and binding obligation enforceable against it in accordance with its terms, subject to any Equitable Defenses;

(vi) it is not Bankrupt and there are no proceedings pending or being contemplated by it or, to its knowledge, threatened against it which would result in it being or becoming Bankrupt;

(vii) there is not pending or, to its knowledge, threatened against it or any of its Affiliates, any legal proceedings that could materially adversely affect its ability to perform its obligations under this Agreement;

(viii) no Event of Default with respect to it has occurred and is continuing and no such event or circumstance would occur as a result of its entering into or performing its obligations under this Agreement;

(ix) it is acting for its own account, has made its own independent decision to enter into this Agreement and as to whether this Agreement is appropriate or proper for it based upon its own judgment, is not relying upon the advice or recommendations of the other Party in so doing, and is capable of assessing the merits of and understanding, and understands and accepts, the terms, conditions and risks of this Agreement; and

(x) it has entered into this Agreement in connection with the conduct of its business and it has the capacity or the ability to make or take delivery of the Product as provided in this Agreement.

(b) **Seller Representations and Warranties.** Seller, and, if applicable, its successors, represents and warrants that throughout the Delivery Term of this Agreement that: (i) the Project qualifies and is certified by the CEC as an Eligible Renewable Energy Resource ("ERR") as such term is defined in Public Utilities Code Section 399.12 or Section 399.16; and (ii) the Project's output delivered to Buyer qualifies under the requirements of the California Renewables Portfolio Standard. To the extent a change in law occurs after execution of this Agreement that causes this representation and warranty to be materially false or misleading, it shall not be an Event of Default if Seller has used commercially reasonable efforts to comply with such change in law.

Seller and, if applicable, its successors, represents and warrants that throughout the Delivery Term of this Agreement the Renewable Energy Credits transferred to Buyer conform to the definition and attributes required for compliance with the California Renewables Portfolio Standard, as set forth in California Public Utilities Commission Decision 08-08-028, and as may be modified by subsequent decision of the California Public Utilities Commission or by subsequent legislation. To the extent a change in law occurs after execution of this Agreement that causes this representation and warranty to be materially false or misleading, it shall not be an Event of Default if Seller has used commercially reasonable efforts to comply with such change in law.

(c) The term "commercially reasonable efforts" as used in Section 10.2(b) of this Agreement shall not require Seller to incur Compliance Costs in excess of the Compliance Cost Cap.

10.3 Covenants.

(a) General Covenants. Each Party covenants that throughout the Delivery Term:

(i) it shall continue to be duly organized, validly existing and in good standing under the Laws of the jurisdiction of its formation;

(ii) it shall maintain (or obtain from time to time as required, including through renewal, as applicable) all regulatory authorizations necessary for it to legally perform its obligations under this Agreement and the Transaction; and

(iii) it shall perform its obligations under this Agreement and the Transaction in a manner that does not violate any of the terms and conditions in its governing documents, any contracts to which it is a party or any Law, rule, regulation, order or the like applicable to it.

(b) Seller Covenants.

(i) Seller covenants throughout the Delivery Term that it will take no action or permit any other person or entity (other than Buyer) to take any action that would impair in any way Buyer's ability to rely on the Project in order to satisfy its Resource Adequacy Requirements; and

(ii) Seller covenants that it shall comply with all CAISO Tariff requirements and/or Participating TO tariff requirements, as applicable, that are applicable to an Interconnection Customer (as defined in the CAISO Tariff or Participating TO's tariff, as applicable) and shall take any other necessary action, including payment of fees and submission of requests, applications or other documentation, to promote the completion of the Electric System Upgrades prior to the RA Start Date.

[The following clause (iii) applies to Existing Projects only:]

(iii) Seller covenants that the Initial Energy Delivery Date shall occur no later than the Expected Initial Energy Delivery Date specified in Section B of the Cover Sheet, except as provided pursuant to Section 11.1(a)(ii).

10.4 Title and Risk of Loss. Title to and risk of loss related to the Product shall transfer from Seller to Buyer at the Delivery Point. Seller warrants that it will deliver to Buyer the Product free and clear of all liens, security interests, Claims and encumbrances or any interest therein or thereto by any person or entity arising prior to or at the Delivery Point.

10.5 Indemnities.

(a) Indemnity by Seller. Seller shall release, indemnify and hold harmless Buyer or Buyers' respective directors, officers, agents, and representatives against and from any and all loss, Claims, actions or suits, including costs and attorney's fees resulting from, or arising out of or in any way connected with (i) the Product delivered under this Agreement to the Delivery Point, or (ii) Seller's operation and/or maintenance of the Project, including any loss, Claim, action or suit, for or on account of injury to, bodily or otherwise, or death of persons, or for damage to or destruction of property belonging to Buyer, Seller, or others, excepting only such loss, Claim, action or suit as may be caused solely by the willful misconduct or gross negligence of Buyer, its Affiliates, or Buyers' and Affiliates' respective agents, employees, directors, or officers.

(b) Indemnity by Buyer. Buyer shall release, indemnify and hold harmless Seller, its directors, officers, agents, and representatives against and from any and all loss, Claims, actions or suits, including costs and attorney's fees resulting from, or arising out of or in any way connected with the Product delivered by Seller under this Agreement after the Delivery Point, including any loss, Claim, action or suit, for or on account of injury to, bodily or otherwise, or death of persons, or for damage to or destruction of property belonging to Buyer, Seller, or others, excepting only such loss, Claim, action or suit as may be caused solely by the willful misconduct or gross negligence of Seller, its Affiliates, or Seller's and Affiliates' respective agents, employees, directors or officers.

(c) No Dedication. Without limitation of each Party's obligations under Sections 10.5(a) and 10.5(b) herein, nothing in this Agreement shall be construed to create any duty to, any standard of care with reference to, or any liability to any person or entity not a Party to this Agreement. No undertaking by one Party to the other under any provision of this Agreement shall constitute the dedication of that Party's system or any portion thereof to the other Party or the public, nor affect the status of Buyer as an independent public utility corporation or Seller as an independent individual or entity.

10.6 Assignment.

(a) General Assignment. Except as provided in Sections 10.6 (b) and (c), neither Party shall assign this Agreement or its rights hereunder without the prior written consent of the other Party, which consent shall not be unreasonably withheld so long as among other things (i) the assignee assumes the transferring Party's payment and performance obligations under this Agreement, (ii) the assignee agrees in writing to be bound by the terms and conditions hereof, (iii) the transferring Party delivers evidence satisfactory to the non-transferring Party of the proposed assignee's technical and financial capability to fulfill the assigning Party's obligations hereunder and (iv) the transferring Party delivers such tax and enforceability assurance as the other Party may reasonably request. Notwithstanding the foregoing and except as provided in Section 10.6(b), consent shall not be required for an assignment of this Agreement where the assigning Party remains subject to liability or obligation under this Agreement, provided that (i) the assignee assumes the assigning Party's payment and performance obligations under this Agreement, (ii) the assignee agrees in writing to be bound by the terms and conditions hereof, and (iii) the assigning Party provides the other Party hereto with at least thirty (30) days' prior written notice of the assignment.

(b) Assignment to Financing Providers. Seller shall be permitted to assign this Agreement as collateral for any financing or refinancing of the Project with the prior written consent of the Buyer, which consent shall not be unreasonably withheld. If Buyer gives its consent, then such consent shall be in a form substantially similar to the Form of Consent to Assignment attached hereto as Appendix VII provided that (i) Buyer shall not be required to consent to any additional terms or conditions beyond those contained in Appendix VII, including extension of any cure periods or additional remedies for financing providers, and (ii) Seller shall be responsible at Buyer's request for Buyer's reasonable costs associated with the review, negotiation, execution and delivery of documents in connection with such assignment, attorneys' fees.

(c) Notice of Change in Control. Except in connection with public market transactions of the equity interests or capital stock of Seller or Seller's Affiliates', Seller shall provide Buyer notice of any direct change of control of Seller (whether voluntary or by operation of Law).

(d) Unauthorized Assignment. Any assignment or purported assignment in violation of this Section 10.6 is void.

10.7 Confidentiality.

(a) Neither Party shall disclose the non-public terms or conditions of this Agreement (the “Confidential Information”) to a third party, other than as follows:

- (i) to the Party’s Affiliates, the Party’s or its Affiliates’ respective employees, lenders, investors, counsel, accountants or advisors who have a need to know such information and have agreed to keep such terms confidential,
- (ii) for disclosure to Buyer’s Procurement Review Group, as defined in CPUC Decision D. 02-08-071, subject to a confidentiality agreement,
- (iii) to the CPUC under seal for purposes of review,
- (iv) for disclosure of those certain terms specified in and pursuant to Section 10.8 of this Agreement;
- (v) in order to comply with any applicable Law, regulation, or any exchange, control area or CAISO rule, or order issued by a court or entity with competent jurisdiction over the disclosing Party (“Disclosing Party”), other than to those entities set forth in subsection (vi);
- (vi) in order to comply with *any* applicable regulation, rule, or order of the CPUC, CEC, or the FERC;
- (vii) to the extent necessary for Buyer to exercise its exclusive rights to the Product during the Delivery Term, including its rights to resell any or all portions of the Product as set forth in Section 3.1(a), other than the Contract Price;
- (viii) for disclosure by Buyer to publicly release generation information of GTSR Projects, in the aggregate with three or more GTSR or RPS-eligible Projects on an annual basis; or
- (ix) for disclosure by Buyer to CRS in connection with Buyer’s Green-e® Energy Certification of the GTSR Program.

(b) The Parties agree that the confidentiality provisions under this Section 10.7 are separate from, and shall not impair or modify any other confidentiality agreements that may be in place between the Parties or their Affiliates; provided however, that the confidentiality provisions of this Section 10.7 shall govern confidential treatment of all non-public information exchanged between the Parties related directly or indirectly to this Agreement as of and after the Effective Date.

10.8 RPS Confidentiality. Notwithstanding Section 10.7(a) of this Agreement, at any time on or after the date on which the Buyer makes its advice filing letter seeking CPUC Approval of this Agreement, either Party shall be permitted to disclose the following terms with respect to such Transaction: Party names, the number of bids per company, Project size, resource type, Delivery Term, Project location, Capacity Factor and Contract Capacity, Commercial Operation Date, Expected Initial Energy Delivery Date, Contract Quantity, Delivery Point, and the achievement of Project development Milestones.

10.9 Audit. Each Party has the right, at its sole expense and during normal working hours, after reasonable Notice, to examine the records of the other Party to the extent reasonably necessary to verify the accuracy of any statement, charge or computation made pursuant to this Agreement including

amounts of Delivered Energy. If any such examination reveals any inaccuracy in any statement, the necessary adjustments in such statement and the payments thereof will be made promptly and shall bear interest calculated at the Interest Rate from the date the overpayment or underpayment was made until paid; provided, however, that no adjustment for any statement or payment will be made unless objection to the accuracy thereof was made prior to the lapse of twelve (12) months from the rendition thereof, and thereafter any objection shall be deemed waived.

10.10 Insurance. Throughout the Term, Seller shall, at its sole cost and expense, obtain and maintain the following insurance coverages and be responsible for its subcontractors, including Seller's EPC Contractors, maintaining sufficient limits of the appropriate insurance coverage. The obligations of the Seller in this Section 10.10 constitute material obligations of the Agreement.

(a) Workers' Compensation and Employers' Liability.

(i) Workers' Compensation insurance indicating compliance with any applicable labor codes, acts, Laws or statutes, state or federal, where Seller performs Work.

(ii) Employers' Liability insurance shall not be less than one million dollars (\$1,000,000.00) for injury or death occurring as a result of each accident.

(b) Commercial General Liability.

(i) Coverage shall be at least as broad as the Insurance Services Office Commercial General Liability Coverage "occurrence" form, with no alterations to the coverage form.

(ii) The limit shall not be less than three million dollars (\$3,000,000.00) each occurrence for bodily injury, property damage, personal injury and products/completed operations. Defense costs shall be provided as an additional benefit and not included within the limits of liability. Coverage limits may be satisfied using an umbrella or excess liability policy or an Owners Contractors Protective (OPC) policy. Limits shall be on a per project basis.

(iii) Coverage shall:

(A) by "Additional Insured" endorsement add as insureds PG&E, its directors, officers, agents and employees with respect to liability arising out of the Work performed by or for the Seller. In the event the Commercial General Liability policy includes a "blanket endorsement by contract," the following language added to the certificate of insurance will satisfy Buyer's requirement: "PG&E, its directors, officers, agents and employees with respect to liability arising out of the Work performed by or for the Seller has been endorsed by blanket endorsement;"

(B) be endorsed (blanket or otherwise) to specify that the Seller's insurance is primary and that any insurance or self-insurance maintained by PG&E shall not contribute with it; and

(C) include a severability of interest clause.

(c) Business Auto.

(i) Coverage shall be at least as broad as the Insurance Services Office Business Auto Coverage form covering Automobile Liability, code 1 "any auto".

(ii) The limit shall not be less than one million dollars (\$1,000,000.00) each accident for bodily injury and property damage.

(iii) If scope of Work involves hauling hazardous materials, coverage shall be endorsed in accordance with Section 30 of the Motor Carrier Act of 1980 (Category 2) and the CA 99 48 endorsement.

(d) All Risk Property Insurance.

(i) During construction, an All Risk Property insurance policy including earthquake and flood (with sublimits as appropriate) shall be maintained during the course of Work being performed and include Start-up and testing for installed equipment and delayed opening coverage. Such policy shall include coverage for materials and equipment while under the care, custody and control of the Seller during the course of Work, at the Site, offsite or while in transit to the Site.

(e) Additional Insurance Requirements.

(i) Before commencing performance of the Work, Seller shall furnish Buyer with certificates of insurance and endorsements of all required insurance for Seller.

(ii) The documentation shall state that coverage shall not be cancelled except after thirty (30) days prior written Notice has been given to Buyer.

(iii) Buyer uses a third party vendor, EXIGIS,LLC to confirm and collect insurance documents. Certificates of insurance and endorsements shall be signed and submitted by a person authorized by that insurer to issue certificates of insurance and endorsements on its behalf, and submitted via email or fax to:

Certificate Holder:
Pacific Gas & Electric Company
c/o EXIGIS, LLC
support@exigis.com
Fax: 646-755-3327

(iv) Reviews of such insurance may be conducted by Buyer on an annual basis.

(v) Upon request, Seller shall furnish Buyer evidence of insurance for its subcontractors.

(f) Form And Content.

All policies or binders with respect to insurance maintained by Seller shall waive any right of subrogation of the insurers hereunder against Buyer, its officers, directors, employees, agents and representatives of each of them, and any right of the insurers to any setoff or counterclaim or any other deduction, whether by attachment or otherwise, in respect of any liability of any such person insured under such policy.

10.11 Access to Financial Information. The Parties agree that Generally Accepted Accounting Principles and SEC rules require Buyer to evaluate if Buyer must consolidate Seller's financial information. Buyer will require access to financial records and personnel to determine if consolidated

financial reporting is required. If Buyer determines that consolidation is required, Buyer shall require the following during every calendar quarter for the Term:

- (a) Complete financial statements and notes to financial statements; and
- (b) Financial schedules underlying the financial statements, all within fifteen (15) days after the end of each fiscal quarter.

Any information provided to Buyer pursuant to this Section 10.11 shall be considered confidential in accordance with the terms of this Agreement and shall only be disclosed on an aggregate basis with other similar entities for which Buyer has power purchase agreements. The information will only be used for financial statement purposes and shall not be otherwise shared with internal or external parties.

10.12 Governing Law. This agreement and the rights and duties of the parties hereunder shall be governed by and construed, enforced and performed in accordance with the laws of the state of California, without regard to principles of conflicts of law. To the extent enforceable at such time, each party waives its respective right to any jury trial with respect to any litigation arising under or in connection with this agreement.

10.13 General. Except to the extent provided for, no amendment or modification to this Agreement shall be enforceable unless reduced to writing and executed by both Parties. The Parties acknowledge and agree that this Agreement is a “forward contract” (within the meaning of the Bankruptcy Code, as in effect as of the Execution Date). This Agreement shall not impart any rights enforceable by any third party (other than a permitted successor or assignee bound to this Agreement). Waiver by a Party of any default by the other Party shall not be construed as a waiver of any other default. The headings used herein are for convenience and reference purposes only. Facsimile or PDF transmission will be the same as delivery of an original document; provided that at the request of either Party, the other Party will confirm facsimile or PDF signatures by signing and delivering an original document; provided, however, that the execution and delivery of this Agreement and its counterparts shall be subject to Section 10.15. This Agreement shall be binding on each Party’s successors and permitted assigns.

10.14 Severability. If any provision in this Agreement is determined to be invalid, void or unenforceable by any court having jurisdiction, such determination shall not invalidate, void, or make unenforceable any other provision, agreement or covenant of this Agreement and the Parties shall use their best efforts to modify this Agreement to give effect to the original intention of the Parties.

10.15 Counterparts. This Agreement may be executed in one or more counterparts each of which shall be deemed an original and all of which shall be deemed one and the same Agreement. Delivery of an executed counterpart of this Agreement by fax will be deemed as effective as delivery of an originally executed counterpart. Any Party delivering an executed counterpart of this Agreement by facsimile will also deliver an originally executed counterpart, but the failure of any Party to deliver an originally executed counterpart of this Agreement will not affect the validity or effectiveness of this Agreement.

10.16 Mobile Sierra. Notwithstanding any provision of this Agreement, neither Party shall seek, nor shall they support any third party seeking, to prospectively or retroactively revise the rates, terms or conditions of service of this Agreement through application or complaint to the FERC pursuant to the provisions of the Federal Power Act, absent prior written agreement of the Parties. Further, absent the prior written agreement in writing by both Parties, the standard of review for changes to the rates,

terms or conditions of service of this Agreement proposed by a Party, a non-Party, or the FERC acting *sua sponte* shall be the “public interest” standard of review set forth in *United States Gas Pipe Line Co. v. Mobile Gas Service Corp.*, 350 U.S. 332 (1956) and *Federal Power Commission v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956).

ARTICLE ELEVEN: TERMINATION EVENT

11.1 Force Majeure Termination Event.

(a) Force Majeure Failure. Buyer shall have the right, but not the obligation, to terminate this Agreement after the occurrence of any of the following: (each constituting a “Force Majeure Failure”):

(i) If prior to the Delivery Term, Seller is unable, due solely to a Force Majeure event, to achieve the Commercial Operation Date or place the Project into Commercial Operation by the Guaranteed Commercial Operation Date, after applicable extensions or cure periods have run, as set forth in Section 3.9(c); provided that if a Force Majeure event is caused by a catastrophic natural disaster, then upon Buyer’s written request to Seller, Seller shall have not more than ninety (90) days from the date of such Force Majeure event to obtain a report from an independent, third party engineer stating whether the Project is capable of being repaired or replaced within such twenty-four (24) month period and Seller shall provide Buyer a copy of the engineer’s report, at no cost to Buyer; provided further that if such engineer’s report concludes that the Project is capable of being repaired or replaced within twenty-four (24) months from the date of the Seller provides the engineer’s report to Buyer and Seller undertakes and continues such repair or replacement with due diligence, then Buyer shall not have the right to terminate this Agreement pursuant to this Section 11.1(a) until the expiration of the repair or replacement period deemed necessary by the engineer’s report (which shall not exceed twenty-four (24) months), after which time, Buyer may terminate this Agreement unless the Project has been repaired or replaced, as applicable, and Seller has resumed and is satisfying its obligations under this Agreement.

(ii) If during the Delivery Term:

(A) the Project fails to deliver at least forty percent (40%) of the Contract Quantity to the Delivery Point for a period of twelve (12) consecutive rolling months following a Force Majeure event that materially and adversely impacts the Project and Buyer has provided Notice to Seller of such failure; provided that, if Seller within forty-five (45) days of receipt of Notice from Buyer, presents Buyer with a plan for mitigation of the effect of the Force Majeure within a period not to exceed six (6) months from the above-mentioned Notice date, which plan is commercially reasonable and satisfactory to Buyer, as evidenced by Buyer’s written acknowledgement of such plan, then Buyer shall not have the right to terminate this Agreement pursuant to this Section 11.1(a) until the expiration of the mitigation period deemed necessary by Seller to repair the Project (which shall not exceed six (6) months); provided that Seller diligently pursues such mitigation plan throughout the mitigation period, and after which time Buyer may terminate this Agreement unless the Project has been repaired, and the Seller has resumed and is satisfying all of its obligations under this Agreement; or

(B) the Project is destroyed or rendered inoperable by a Force Majeure event caused by a catastrophic natural disaster; provided that Seller shall have up to ninety (90) days following such Force Majeure event to obtain a report from an independent, third party engineer stating whether the Project is capable of being repaired or replaced no later than twenty-four (24) months from the date of the report and Seller shall provide Buyer with a copy of the engineer’s report, at no cost to Buyer; provided further that if such engineer’s report concludes that the Project is capable of being repaired or replaced within such twenty-four (24) month period and Seller undertakes and continues such

repair or replacement with due diligence, then Buyer shall not have the right to terminate this Agreement pursuant to this Section 11.1(a) until the expiration of the period deemed necessary by the engineer's report (which shall not exceed twenty-four (24) months), after which time, Buyer may terminate this Agreement unless the Project has been repaired or replaced, as applicable, and the Seller has resumed and is satisfying all of its obligations under this Agreement.

(b) Termination and Right of First Offer.

(i) If Buyer exercises its termination right in connection with the Force Majeure Failure, then the Agreement shall terminate without further liability of either Party to the other, effective upon the date set forth in Buyer's Notice of termination, subject to each Party's satisfaction of all of the final payment and survival obligations set forth in Sections 2.6(a) and (b). The Parties agree that for a period of three (3) years from the date on which Buyer Notifies Seller of termination due to the Force Majeure Failure ("Exclusivity Period"), neither Seller, its successors and assigns, nor its Affiliates shall enter into an obligation or agreement to sell or otherwise transfer any Products from the Project to any third party, unless Seller first offers, in writing, to sell to Buyer such Products from the Project on the same terms and conditions as this Agreement, subject to permitted modifications identified in subpart (ii) below, (the "First Offer") and Buyer either accepts or rejects such First Offer in accordance with the provisions herein.

(ii) If Buyer accepts the First Offer, Buyer shall Notify Seller within thirty (30) days of receipt of the First Offer subject to Buyer's management approval and CPUC Approval ("Buyer's Notice of First Offer Acceptance"), and then the Parties shall have not more than ninety (90) days from the date of Buyer's Notice of First Offer Acceptance to enter into a new power purchase agreement, in substantially the same form as this Agreement, or amend this Agreement, subject to CPUC Approval, if necessary; provided that the Contract Price may only be increased to reflect Seller's documented incremental costs in overcoming the Force Majeure event.

(iii) If Buyer rejects or fails to accept Seller's First Offer within thirty (30) days of receipt of such offer, Seller shall thereafter be free to sell or otherwise transfer, and to enter into agreements to sell or otherwise transfer, any Products from the Project to any third party, so long as the material terms and conditions of such sale or transfer are not more favorable to the third party than those of the First Offer to Buyer. If, during the Exclusivity Period, Seller desires to enter into an obligation or agreement with a third party, Seller shall deliver to Buyer a certificate of an authorized officer of Seller (A) summarizing the material terms and conditions of such agreement and (B) certifying that the proposed agreement with the third party will not provide Seller with a lower rate of return than that offered in the First Offer to Buyer. If Seller is unable to deliver such a certificate to Buyer, then Seller may not sell or otherwise transfer, or enter into an agreement to sell or otherwise transfer, the Products from the Project without first offering to sell or otherwise transfer such Products to Buyer on such more favorable terms and conditions (the "Revised Offer") in accordance with subpart (ii) above. If within thirty (30) days of receipt of Seller's Revised Offer the Buyer rejects, or fails to accept by Notice to Seller, the Revised Offer, then Seller will thereafter be free to sell or otherwise transfer, and to enter into agreements to sell or otherwise transfer, such Products from the Project to any third party on such terms and conditions as set forth in the certificate.

ARTICLE TWELVE: DISPUTE RESOLUTION

12.1 Intent of the Parties. Except as provided in the next sentence, the sole procedure to resolve any claim arising out of or relating to this Agreement is the dispute resolution procedure set forth in this Article Twelve. The lone exception to the foregoing is that either Party may seek an injunction in Superior Court in San Francisco, California if such action is necessary to prevent irreparable harm, in

which case both Parties nonetheless will continue to pursue resolution of all other aspects of the dispute by means of this procedure.

12.2 Management Negotiations.

(a) The Parties will attempt in good faith to resolve any controversy or claim arising out of or relating to this Agreement by prompt negotiations between each Party's Authorized Representative, or such other person designated in writing as a representative of the Party (each a "Manager"). Either Manager may request a meeting, to be held in person or telephonically, to initiate negotiations to be held within ten (10) Business Days of the other Party's receipt of such request, at a mutually agreed time and place. If the matter is not resolved within fifteen (15) Business Days of their first meeting ("Initial Negotiation End Date"), the Managers shall refer the matter to the designated senior officers of their respective companies ("Executive(s)"), who shall have authority to settle the dispute. Within five (5) Business Days of the Initial Negotiation End Date ("Referral Date"), each Party shall provide one another written Notice confirming the referral and identifying the name and title of the Executive who will represent the Party.

(b) Within five (5) Business Days of the Referral Date, the Executives shall establish a mutually acceptable location and date to meet, which date shall not be greater than thirty (30) days from the Referral Date. After the initial meeting date, the Executives shall meet, as often as they reasonably deem necessary, to exchange relevant information and to attempt to resolve the dispute.

(c) All communication and writing exchanged between the Parties in connection with these negotiations shall be deemed confidential and subject to the confidentiality provisions of this Agreement. All such communication and writing shall be inadmissible as evidence such that it cannot be used or referred to in any subsequent binding adjudicatory process between the Parties, whether with respect to this dispute or any other.

(d) If the matter is not resolved within forty-five (45) days of the Referral Date, or if the Party receiving the written request to meet, pursuant to Section 12.2(a), refuses or does not meet within the ten (10) Business Day period specified in Section 12.2(a), either Party may initiate mediation of the controversy or claim according to the terms of the following Section 12.3.

12.3 Arbitration Initiation. If the dispute cannot be resolved by negotiation as set forth in Section 12.2 above, then the Parties shall resolve such controversy through Arbitration. The Arbitration shall be adjudicated by one retired judge or justice from the JAMS panel. The Arbitration shall take place in San Francisco, California, and shall be administered by and in accordance with JAMS's Commercial Arbitration Rules ("Arbitration"). If the Parties cannot mutually agree on the arbitrator who will adjudicate the dispute, then JAMS shall provide the Parties with an arbitrator pursuant to its then-applicable Commercial Arbitration Rules. The arbitrator shall have no affiliation with, financial or other interest in, or prior employment with either Party and shall be knowledgeable in the field of the dispute. Either Party may initiate Arbitration by filing with the JAMS a notice of intent to arbitrate within one hundred and twenty (120) days of service of the Referral Date.

12.4 Arbitration Process. At the request of a Party, the arbitrator shall have the discretion to order depositions of witnesses to the extent the arbitrator deems such discovery relevant and appropriate. Depositions shall be limited to a maximum of three (3) per Party and shall be held within thirty (30) days of the making of a request. Additional depositions may be scheduled only with the permission of the arbitrator, and for good cause shown. Each deposition shall be limited to a maximum of six (6) hours duration unless otherwise permitted by the arbitrator for good cause shown. All objections are reserved for the Arbitration hearing except for objections based on privilege and proprietary and Confidential

Information. The arbitrator shall also have discretion to order the Parties to exchange relevant documents. The arbitrator shall also have discretion to order the Parties to answer interrogatories, upon good cause shown.

(a) Each of the Parties shall submit to the arbitrator, in accordance with a schedule set by the arbitrator, offers in the form of the award it considers the arbitrator should make. If the arbitrator requires the Parties to submit more than one such offer, the arbitrator shall designate a deadline by which time the Parties shall submit their last and best offer. In such proceedings the arbitrator shall be limited to awarding only one of the two “last and best” offers submitted, and shall not determine an alternative or compromise remedy.

(b) The arbitrator shall have no authority to award punitive or exemplary damages or any other damages other than direct and actual damages and the other remedies contemplated by this Agreement.

(c) The arbitrator’s award shall be made within nine (9) months of the filing of the notice of intention to arbitrate (demand) and the arbitrator shall agree to comply with this schedule before accepting appointment. However, this time limit may be extended by agreement of the Parties or by the arbitrator, if necessary. The California Superior Court of the City and County of San Francisco may enter judgment upon any award rendered by the arbitrator. The Parties are aware of the decision in *Advanced Micro Devices, Inc. v. Intel Corp.*, 9 Cal. 4th 362 (1994) and, except as modified by this Agreement, intend to limit the power of the arbitrator to that of a Superior Court judge enforcing California Law.

(d) The prevailing Party in this dispute resolution process is entitled to recover its costs and reasonable attorneys’ fees.

(e) The arbitrator shall have the authority to grant dispositive motions prior to the commencement of or following the completion of discovery if the arbitrator concludes that there is no material issue of fact pending before him or her.

(f) Except as may be required by Law, neither a Party nor an arbitrator may disclose the existence, content, or results of any Arbitration hereunder without the prior written consent of both Parties.

ARTICLE THIRTEEN: NOTICES

Whenever this Agreement requires or permits delivery of a “Notice” (or requires a Party to “notify”), the Party with such right or obligation shall provide a written communication in the manner specified herein; provided, however, that notices of Outages or other Scheduling or dispatch information or requests, as provided in Appendix VI, shall be provided in accordance with the terms set forth in the relevant section of this Agreement. Notices may be sent by facsimile or e-mail. A Notice sent by facsimile transmission or e-mail will be recognized and shall be deemed received on the Business Day on which such Notice was transmitted if received before 5:00 p.m. (and if received after 5:00 p.m., on the next Business Day) and a Notice of overnight mail or courier shall be deemed to have been received two (2) Business Days after it was sent or such earlier time as is confirmed by the receiving Party. Either Party may periodically change any address, phone number, e-mail, website, or contact, including such information in Appendix VI and the “Notices List” in the Cover Sheet, to which Notice is to be given it by providing Notice of such change to the other Party.

SIGNATURES

Agreement Execution

In WITNESS WHEREOF, each Party has caused this Agreement to be duly executed by its authorized representative as of the dates provided below:

[SELLER, a (*include place of formation and business type*)]

**PACIFIC GAS AND ELECTRIC COMPANY,
a California corporation**

Signature: _____	Signature: _____
Name: _____	Name: _____
Title: _____	Title: _____
Date: _____	Date: _____

APPENDIX I

FORM OF LETTER OF CREDIT

Issuing Bank Letterhead and Address

STANDBY LETTER OF CREDIT NO. XXXXXXXXX

Date: [insert issue date]

Beneficiary: Pacific Gas and Electric Company
77 Beale Street, Mail Code B28L
San Francisco, CA 94105
Attention: Credit Risk Management

Applicant: [Insert name and address of Applicant]

Letter of Credit Amount: [insert amount]

Expiry Date: [insert expiry date]

Ladies and Gentlemen:

By order of **[insert name of Applicant]** ("Applicant"), we hereby issue in favor of Pacific Gas and Electric Company (the "Beneficiary") our irrevocable standby letter of credit No. **[insert number of letter of credit]** ("Letter of Credit"), for the account of Applicant, for drawings up to but not to exceed the aggregate sum of U.S. \$ **[insert amount in figures followed by (amount in words)]** ("Letter of Credit Amount"). This Letter of Credit is available with **[insert name of issuing bank, and the city and state in which it is located]** by sight payment, at our offices located at the address stated below, effective immediately, and it will expire at our close of business on **[insert expiry date]** (the "Expiry Date").

Funds under this Letter of Credit are available to the Beneficiary against presentation of the following documents:

1. Beneficiary's signed and dated sight draft in the form of Exhibit A hereto, referencing this Letter of Credit No. **[insert number]** and stating the amount of the demand; and
2. One of the following statements signed by an authorized representative or officer of Beneficiary:
 - A. "Pursuant to the terms of that certain **[insert name of the agreement]** (the "Agreement"), dated **[insert date of the Agreement]**, between Beneficiary and **[insert name of Seller under the Agreement]**, Beneficiary is entitled to draw under Letter of Credit No. **[insert number]** amounts owed by **[insert name of Seller under the Agreement]** under the Agreement; or
 - B. "Letter of Credit No. **[insert number]** will expire in thirty (30) days or less and **[insert name of Seller under the Agreement]** has not provided replacement security acceptable to Beneficiary.

Special Conditions:

1. Partial and multiple drawings under this Letter of Credit are allowed;
2. All banking charges associated with this Letter of Credit are for the account of the Applicant;
3. This Letter of Credit is not transferable; and
4. The Expiry Date of this Letter of Credit shall be automatically extended without a written amendment for a period of one year and on each successive Expiry Date, unless at least sixty (60) days before the then current Expiry Date, we notify you by registered mail or courier that we elect not to extend the Expiry Date of this Letter of Credit for such additional period.

We engage with you that drafts drawn under and in compliance with the terms of this Letter of Credit will be duly honored upon presentation, on or before the Expiry Date (or after the Expiry Date as provided below), at our offices at **[insert issuing bank's address for drawings]**.

All demands for payment shall be made by presentation of originals or copies of documents; or by facsimile transmission of documents to **[insert fax number]**, Attention: **[insert name of issuing bank's receiving department]**, with originals or copies of documents to follow by overnight mail. If presentation is made by facsimile transmission, you may contact us at **[insert phone number]** to confirm our receipt of the transmission. Your failure to seek such a telephone confirmation does not affect our obligation to honor such a presentation.

Our payments against complying presentations under this Letter of Credit will be made no later than on the sixth (6th) banking day following a complying presentation.

Except as stated herein, this Letter of Credit is not subject to any condition or qualification. It is our individual obligation, which is not contingent upon reimbursement and is not affected by any agreement, document, or instrument between us and the Applicant or between the Beneficiary and the Applicant or any other party.

Except as otherwise specifically stated herein, this Letter of Credit is subject to and governed by the *Uniform Customs and Practice for Documentary Credits, 2007 Revision*, International Chamber of Commerce (ICC) Publication No. 600 (the "UCP 600"); provided that, if this Letter of Credit expires during an interruption of our business as described in Article 36 of the UCP 600, we will honor drafts presented in compliance with this Letter of Credit within thirty (30) days after the resumption of our business and effect payment accordingly.

The law of the State of New York shall apply to any matters not covered by the UCP 600.

For telephone assistance regarding this Letter of Credit, please contact us at **[insert number and any other necessary details]**.

Very truly yours,

[insert name of issuing bank]

By: _____
Authorized Signature

Name: _____ **[print or type name]**

Title: _____

Exhibit A SIGHT DRAFT

TO
[INSERT NAME AND ADDRESS OF PAYING BANK]

AMOUNT: \$ _____ DATE: _____

AT SIGHT OF THIS DEMAND PAY TO THE ORDER OF PACIFIC GAS AND ELECTRIC
COMPANY THE AMOUNT OF U.S.\$ _____ (_____ U.S. DOLLARS)

DRAWN UNDER [INSERT NAME OF ISSUING BANK] LETTER OF CREDIT NO. XXXXXX.

REMIT FUNDS AS FOLLOWS:

[INSERT PAYMENT INSTRUCTIONS]

DRAWER

BY: _____
NAME AND TITLE

APPENDIX II

INITIAL ENERGY DELIVERY DATE CONFIRMATION LETTER

In accordance with the terms of that certain Power Purchase Agreement dated _____ (“Agreement”) by and between _____ (“Buyer”) and _____ (“Seller”), this letter (“Initial Energy Delivery Date Confirmation Letter”) serves to document the Parties’ further agreement that (i) the Conditions Precedent to the occurrence of the Initial Energy Delivery Date have been satisfied, and (ii) Buyer has accepted delivery of the Product, as specified in the Agreement, as of this _____ day of _____, _____ (the “Initial Energy Delivery Date”). All capitalized terms not defined herein shall have the meaning set forth in the Agreement.

Seller represents to Buyer that it has been granted status as an [Exempt Wholesale Generator] [Qualifying Facility]. Additionally Seller provides the following FERC Tariff information for reference purposes only:

Tariff:

Dated:

Docket Number:

IN WITNESS WHEREOF, each Party has caused this Initial Energy Delivery Date Confirmation Letter to be duly executed by its authorized representative as of the date of last signature provided below:

[**SELLER**]

PACIFIC GAS AND ELECTRIC COMPANY

Signature: _____	Signature: _____
Name: _____	Name: _____
Title: _____	Title: _____
Date: _____	Date: _____

APPENDIX III
FORM OF PROGRESS REPORT

Progress Report

of

("Seller")

provided to

Pacific Gas and Electric Company
("Buyer")

[Date]

Instructions.

Any capitalized terms used in this report which are not defined herein shall have the meaning ascribed to them in the Power Purchase Agreement by and between _____, (“Seller”) and Pacific Gas and Electric Company dated _____, (the “Agreement”).

Seller shall review the status of each Milestone of the construction schedule for the Project and Seller shall identify such matters referenced in clauses (i)-(v) below as known to Seller and which in Seller’s reasonable judgment are expected to adversely affect the schedule, and with respect to any such matters, shall state the actions which Seller intends to take to ensure that the Milestones will be attained by their required dates. Such matters may include, but shall not be limited to:

- (i) Any material matter or issue arising in connection with a Governmental Approval, or compliance therewith, with respect to which there is an actual or threatened dispute over the interpretation of a Law, actual or threatened opposition to the granting of a necessary Governmental Approval, any organized public opposition, any action or expenditure required for compliance or obtaining approval that Seller is unwilling to take or make, or in each case which could reasonably be expected to materially threaten or prevent financing of the Units or related Project, attaining any Milestone, or obtaining any contemplated agreements with other parties which are necessary for attaining any Milestone or which otherwise reasonably could be expected to materially threaten Seller’s ability to attain any Milestone.
- (ii) Any development or event in the financial markets or the independent power industry, any change in taxation or accounting standards or practices or in Seller’s business or prospects which reasonably could be expected to materially threaten financing of the Project, attainment of any Milestone or materially threaten any contemplated agreements with other parties which are necessary for attaining any Milestone or could otherwise reasonably be expected to materially threaten Seller’s ability to attain any Milestone;
- (iii) A change in, or discovery by Seller of, any legal or regulatory requirement which would reasonably be expected to materially threaten Seller’s ability to attain any Milestone;
- (iv) Any material change in the Seller’s schedule for initiating or completing any material aspect of Project;
- (v) The status of any matter or issue identified as outstanding in any prior Progress Report and any material change in the Seller’s proposed actions to remedy or overcome such matter or issue.

For guidance, each “overview” subsection shall include a summary of the status and progress of major activities associated with that section, whether planned, in progress, or completed, including relevant dates. Each “recent activities” subsection shall include details of activities during the previous month. Each “expected activities” subsection shall include a brief list of major activities planned for the current month.

Seller shall complete, certify, and deliver this form of Progress Report to [REDACTED], together with all attachments and exhibits, with copies of this report delivered to GCMTGroup@pge.com and [REDACTED].

1. Executive Summary

Please provide an overview of the Project, including technology, size, location, and ownership.

Please provide a brief chronological cumulative summary of the **major** activities completed for each of the following aspects of the Project. Include the date each item was added to the summary (*e.g., in Milestone section “January 2012 – notice of Construction Start Date milestone achieved was reported to PG&E on January 15, 2012” and in Construction section “January 2012 - Notice to Proceed was issued to EPC contractor on January 10, 2012”*):

- 1.1 Milestones**
- 1.2 Governmental Approvals**
- 1.3 Financing**
- 1.4 Property Acquisition**
- 1.5 Design and Engineering**
- 1.6 Major Equipment procurement**
- 1.7 Construction**
- 1.8 Interconnection**
- 1.9 Startup**

2. Milestones

In this section, please include information on each Milestone listed in the Cover Sheet, plus any additional significant milestones related to the project.

2.1 Milestone schedule

Please state the status and progress of each Milestone. Provide the date of completion of completed Milestone(s) and the expected date of completion of uncompleted Milestone(s). The expected date is the current best estimate, and may change from time to time as better information becomes available.

2.2 Remedial Action Plan (applicable if Seller fails to achieve a Milestone by the Milestone Date)

Please describe in detail any delays (actual or anticipated) beyond the scheduled Milestone dates. Describe the cause of the delay (*e.g., governmental approvals, financing, property acquisition, design activities, equipment procurement, project construction, interconnection, or any other factor*). Describe Seller’s Remedial Action Plan which shall include detailed plans to achieve the missed Milestone and subsequent Milestones.

3. Governmental Approvals

In this section, please include information on each of the Governmental Approvals required for the construction of the Units and the status thereof. List the applicable government agency, the type of application/approval requested, and the dates (expected or actual) of significant activity. Significant activity includes, but is not limited to, application submission, notice of complete application, notice of preparation, public hearing or comment period, draft documents and/or approvals, final documents and/or approvals, notice of determination, and/or issuance of permit. If the government agency maintains a website with information on the approval process for the Project, please provide a link.

3.1 Environmental Impact Report/Statement (EIR/EIS)

Please describe the environmental review process and each of the Governmental Approval(s) to be obtained for the Project. Provide the status and completion date (expected or actual) of each significant activity in the process.

3.2 Other Governmental Approvals

Please describe each of the other Governmental Approvals to be obtained for the Project. Provide the status and completion date (expected or actual) of each significant activity.

3.3 Recent Governmental Approval activities

Please describe in detail the Governmental Approval activities that occurred during the previous calendar month.

3.4 Expected Governmental Approval activities

Please list all Governmental Approval activities that are expected to be performed during the current calendar month.

3.5 Governmental Approval Notices received

Please attach to this Progress Report copies of any Notices related to Governmental Approval activities received during the previous calendar month.

4. Financing Activities

In this section, please include information on each separate phase of financing for the Project. Include information on debt, equity, and/or federal or state loans or grants.

4.1 Overview of financing activities

Please provide a summary of the status and progress of each major financing activity, including the date of execution of significant documents, and information on the expected timing of future significant activities.

4.2 Recent financing activities

Please describe in detail the financing activities that occurred during the previous calendar month.

4.3 Expected financing activities

Please list the financing activities that are expected to be performed during the current calendar month.

5. Property Acquisition Activities

In this section, please include information on property acquisition or site control activities for the Project.

5.1 Overview of property acquisition activities

Please provide a summary of the status and progress of each major property acquisition activity, including the date of execution of significant documents, and information on the expected timing of future significant activities.

5.2 Recent property acquisition activities

Please describe in detail the property acquisition activities that occurred during the previous calendar month.

5.3 Expected property acquisition activities

Please list the property acquisition activities that are expected to be performed during the current calendar month.

6. Design and Engineering Activities

In this section, please include information on the status of design and engineering for the Project.

6.1 Overview of design activities

Please provide a summary of the status and progress of each major design or engineering activity, including dates of completion of significant activities and expected timing of future activities.

6.2 Recent design activities

Please describe in detail the design activities that occurred during the previous calendar month.

6.3 Expected design activities

Please list the design activities that are expected to be performed during the current calendar month.

7. Major Equipment Procurement

In this section, please include information on all major equipment to be procured for all portions of the Project to be completed by Seller, including switchyards, substations and any other interconnection equipment, in addition to generating and auxiliary equipment.

7.1 Overview of major equipment procurement activities

For each type of equipment, list the number of each major item to be procured, the manufacturer, model number (if applicable), and rating. List the delivery schedule (expected or actual as applicable), breaking out the number of each item (to be) procured or delivered in each month.

7.2 Recent major equipment procurement activities

Please describe in detail the major equipment procurement activities that occurred during the previous calendar month.

7.3 Expected major equipment procurement activities

Please list the major equipment procurement activities that are expected to be performed during the current calendar month.

8. Construction Activities

In this section, please include information on the status of any construction-related factors that may affect the ability of the Project to deliver Product to the Buyer. Include information on the Project infrastructure, generating equipment, and major auxiliary equipment. Also include information on the substations, switchyards, gen-ties, telecommunications equipment or other interconnection facilities that are the direct responsibility of the Project.

8.1 Overview of major construction activities

Please provide a summary of the status and progress of each major construction activity for all portions of the Project, including a schedule showing expected or actual dates as applicable. Provide the name of the EPC Contractor, the date of execution of the EPC Contract, and the date of issuance of a full Notice to Proceed (or equivalent). For each major type of equipment, break out the number of each item (to be) installed and/or commissioned in each month.

8.2 Recent construction activities

Please describe in detail the construction activities that occurred during the previous calendar month.

8.3 Expected construction activities

Please list the interconnection activities that are expected to be performed during the current calendar month.

8.4 EPC Contractor Progress Report

Please attach a copy of the Progress Reports received during the previous calendar month from the EPC Contractor pursuant to the construction contract between Seller and EPC Contractor, certified by the EPC Contractor as being true and correct as of the date issued.

8.5 Look-ahead construction schedule

Please provide a look-ahead construction schedule covering at least three months.

8.6 OSHA Recordables

Please list all OSHA recordables from the previous calendar month.

8.7 Work stoppages

Please describe any work stoppage from the previous calendar month and its effect on the construction schedule.

9. Interconnection Activities

In this section, please include information on interconnection-related factors that may affect the ability of the Project to deliver Product to the Buyer. Include information on the status of interconnection studies, Interconnection Agreements, design and construction of Interconnection Facilities (e.g., substations, switchyards, gen-ties, system protection schemes, telecommunications equipment to the extent not already covered in the Project construction information in Section 8), Network Upgrades, and grid outage and/or interconnection schedules.

9.1 Overview of interconnection activities

Please provide a summary of the status and progress of each major interconnection activity including dates of completion of significant activities and expected timing of future activities.

9.2 Recent interconnection activities

Please describe in detail the interconnection activities that occurred during the previous calendar month.

9.3 Expected interconnection activities

Please list the interconnection activities that are expected to be performed during the current calendar month.

10. Startup

In this section, please include information on the status of activities related to preparation for Commercial Operation, including equipment testing, commissioning, release to operations, requirements of the grid operator, and any other activities that must be conducted before the Project may deliver Energy to the grid and/or declare Commercial Operation.

10.1 Overview of startup activities

Please provide a summary of the status and progress of each major startup activity including dates of completion of significant activities and expected timing of future activities.

10.2 Recent startup activities

Please describe in detail the startup activities that occurred during the previous calendar month.

10.3 Expected startup activities

Please list the startup activities that are expected to be performed during the current calendar month.

I, _____, on behalf of and as an authorized representative of _____, do hereby certify that any and all information contained in this Seller's Progress Report is true and accurate, and reflects, to the best of my knowledge, the current status of the construction of the Project as of the date specified below.

By: _____

Name: _____

Title: _____

Date: _____

APPENDIX IV

CONSTRUCTION START AND COMMERCIAL OPERATION CERTIFICATION FORMS AND PROCEDURES

Appendix IV-1: CONSTRUCTION START FORM OF CERTIFICATION

Appendix IV-2: COMMERCIAL OPERATION CERTIFICATION PROCEDURE

Attachment A Commercial Operation Form of Certification

Appendix IV-3: CAPACITY TEST PROCEDURE [*Use for Baseload Product only*]

[Use this Appendix IV—1 for BOTH As-Available and Baseload Products]

APPENDIX IV-1

**CONSTRUCTION START
FORM OF CERTIFICATION**

____ (Date) ____

Director Contract Management and Settlements
Pacific Gas and Electric Company
77 Beale Street, Mail Code N12E
San Francisco, CA 94105-1702

Re: Construction Start Date

This certification ("Certification") of the Construction Start Date is delivered by _____ ("Seller") to Pacific Gas and Electric Company ("Buyer") in accordance with the terms of that certain Power Purchase Agreement dated _____ ("Agreement") by and between Seller and Buyer. All capitalized terms used in this Certification but not otherwise defined herein shall have the respective meanings assigned to such terms in the Agreement. Seller hereby certifies and represents to Buyer all of the following:

- a) the EPC Contract related to the Project was executed on _____;
- b) [permitting agency name] _ issued grading permits to the Seller on _____; and
- c) the Notice to Proceed was issued on _____ (attached), and.
- d) mobilization at the Project Site commenced on _____.

IN WITNESS WHEREOF, the undersigned has executed this certificate on behalf of the Seller as of the ____ day of _____.

(Seller)

(Name)

(Position)

[LICENSED PROFESSIONAL ENGINEER]

By: _____

Name: _____

Title: _____

Date: _____

APPENDIX IV-2

COMMERCIAL OPERATION CERTIFICATION PROCEDURE

In accordance with the terms of that certain Power Purchase Agreement dated _____, 20__ by and between Pacific Gas and Electric Company (“Buyer”) and _____ (“Seller”) to declare and recognize the Commercial Operation Date of the Project, Seller shall provide all of the documents set forth herein to Buyer as of the Commercial Operation Date. All terms not defined herein shall have the meaning set forth in the Agreement.

- (1) A certification from an authorized officer of Seller, substantially in the form of Attachment A to this Appendix IV-2, dated as of the Commercial Operation Date; and
- (2) A certificate or report from a Licensed Professional Engineer containing all of the following:
 - (a) A statement that the Project has achieved Mechanical Completion and the date on which it was achieved;
 - (b) A statement that the Project has successfully completed Project Testing and the dates on which Seller has accepted the test results; and
 - (c) A statement that the Project has achieved Substantial Completion and the date on which it was achieved.
- (3) Seller has provided to Buyer all documents which demonstrate that Seller has satisfied all of the CAISO agreement, interconnection agreement, and metering requirements in Sections 3.4 and 3.6 and has enabled Buyer to schedule the Facility with the CAISO for the Facility’s full unrestricted output.
- (4) Definitions.
 - (a) “Mechanical Completion” means that (i) all components and systems of the Project have been properly constructed, installed and functionally tested according to EPC Contract requirements in a safe and prudent manner that does not void any equipment or system warranties or violate any permits, approvals or Laws; (ii) the Project is ready for startup testing and commissioning; (iii) Seller has provided written acceptance to the EPC Contractor of mechanical completion as that term is specifically defined in the EPC Contract.
 - (b) “Project Testing Completion” means the written acceptance to the EPC Contractor of the completion of startup testing / commissioning, emissions testing (as applicable), and performance / acceptance / warranty testing (all such testing shall be collectively referred to as “Project Testing”) as required under the EPC Contract. The objectives of the tests shall be generally (i) to verify that the Project has been properly designed and constructed to meet the performance and operating requirements of the EPC Contract; (ii) to assure warranty coverage for equipment and systems over their warranty periods.
 - (c) “Substantial Completion” means when the following has occurred: (i) the Project is sufficiently complete, in accordance with the EPC Contract, that Seller has full and unrestricted use and benefit of the Project in the use for which it is intended; (ii) the Project has achieved Mechanical Completion; (iii) utilities are fully connected and operating normally; (iv) all necessary permits have been issued; (v) the Project is fully and properly interconnected and synchronized with the electrical grid and is capable of producing electricity in accordance with the EPC Contract; (vi) the operating manual has been approved by Seller; (vii) all work other than incidental corrective and incidental punch list work is complete; and (viii) Seller has provided written acceptance to the EPC Contractor of substantial completion as that term is specifically defined in the EPC Contract.

APPENDIX IV-2 –Attachment A

**COMMERCIAL OPERATION
FORM OF CERTIFICATION**

This certification (“Certification”) of Commercial Operation is delivered by _____ (“Seller”) to Pacific Gas and Electric Company (“Buyer”) in accordance with the terms of that certain Power Purchase Agreement dated _____ (“Agreement”) by and between Seller and Buyer. All capitalized terms used in this Certification but not otherwise defined herein shall have the respective meanings assigned to such terms in the Agreement.

Seller hereby certifies and represents to Buyer the following:

- (1) Mechanical Completion of the Project was achieved on ____ [DATE] ____.
- (2) Project Testing Completion successfully occurred on:

[Seller to indicate each type of Project Testing and date completed]

- (a) NAME OF TEST [DATE]
 - (b) NAME OF TEST [DATE]
 - (c) NAME OF TEST [DATE]
- (3) Substantial Completion of the Project was achieved on ____ [DATE] ____
- (4) Pre-parallel inspection of the Project was successfully completed on ____ [DATE] ____
- (5) Authorization to parallel the Project was obtained on ____ [DATE] ____
- (6) Telemetry / SCADA visibility with PTO and CAISO grid control and power dispatch centers was obtained for the Project on ____ [DATE] ____
- (7) Reliability Network Upgrades (as defined in the CAISO Tariff) were completed on the Project on ____ [DATE] ____
- (8) Power system stabilizer testing and calibration was obtained for the Project on ____ [DATE] ____
or, ☐ was not required
- (9) Full Capacity Deliverability Status Finding from CAISO was obtained for the Project on ____ [DATE] ____ or, ☐ was not required because the Project is Energy Only.
- (10) The Participating Transmission Provider or Distribution Provider has provided documentation supporting full unrestricted release for Commercial Operation by [Name of Participating Transmission Owner as appropriate] on ____ [DATE] ____.
- (11) The CAISO has provided notification supporting Commercial Operation, in accordance with the CAISO tariff on ____ [DATE] ____.

A certified statement of the Licensed Professional Engineer, attached hereto, has been provided as evidence of Commercial Operation of the Project to provide Product and meet, at a minimum, the requirements indicated herein.

EXECUTED by SELLER this _____ day of _____, 20__.

[Licensed Professional Engineer]

Signature: _____	Signature: _____
Name: _____	Name: _____
Title: _____	Title: _____
	Date: _____
License Number and LPE Stamp _____	

[Use for Baseload Product only]

APPENDIX IV–3

CAPACITY TEST PROCEDURE

[To be developed by Buyer and Seller by using CAISO test procedures for the applicable technology]

APPENDIX V

GEP DAMAGES CALCULATION

In accordance with the provisions in Section 3.1(e)(ii), GEP Damages means the liquidated damages payment due by Seller to Buyer, calculated as follows:

$$[(A-B) \times (C-D)]$$

Where:

A = the Guaranteed Energy Production for the Performance Measurement Period, in MWh

B = Sum of Delivered Energy plus Deemed Delivered Energy, if any, over the Performance Measurement Period, in MWh

C = Replacement price for the Performance Measurement Period, in \$/MWh, which is the sum of (a) the simple average of the Integrated Forward Market hourly price for all the hours in the Performance Measurement Period, as published by the CAISO, for the Existing Zone Generation Trading Hub (as defined in the CAISO Tariff), in which the PNode resides, plus (b) \$50/MWh

D = the unweighted Contract Price specified in the Cover Sheet for the Performance Measurement Period, in \$/MWh

The Parties agree that in the above calculation of GEP Damages, the result of “(C-D)” is less than \$20/MWh, the “(C-D)” will be replaced with \$20/MWh.

APPENDIX VI

NOTIFICATION REQUIREMENTS FOR AVAILABLE CAPACITY AND PROJECT OUTAGES

A. NOTIFICATION REQUIREMENTS FOR ROUTINE START-UP AND SHUTDOWNS

Prior to paralleling or after disconnecting from the electric system, ALWAYS follow your balancing authority rules and notify the applicable Participating Transmission Owner's (PTO) switching center

- Call the applicable Participating Transmission Owner's (PTO) switching center and Buyer's Real-Time Desk to advise of the intent to parallel before any Start-up.
- Call the applicable Participating Transmission Owner's (PTO) switching center and Buyer's Real-Time Desk after the unit has been paralleled and report the parallel time and intended unit output.
- Call the applicable Participant Transmission Owner's (PTO) switching center and Buyer's Real-Time Desk after any routine separation and report the separation time as well as the date and time estimate for return to service.

B. SUBMISSION OF AVAILABLE CAPACITY AND PLANNED OUTAGES

1. Submit information by posting to PG&E's approved web-based system, which is located at www.pge.com under "Business to Business," or alternative website designated by PG&E (both, "PG&E's Website"). Once directed to the appropriate page, enter the username and password assigned by PG&E's Bilateral Settlements Group. If PG&E's Website is unavailable, implement the procedures set forth below:
 - a. **For all email correspondence, enter the following in the email subject field: Delivery Date Range, Company Name, Contract Name, Email Purpose, Date Range (For example: "dd/mm/yyyy through dd/mm/yyyy, XYZ Company Project #2, Daily Forecast of Available Capacity,")**
 - b. For Annual Forecasts of Available Capacity, email to DAenergy@pge.com and Bilat_Settlements@pge.com.
 - c. For Monthly and Daily Forecasts of Available Capacity, email to DAenergy@pge.com.
 - d. For Daily Forecasts of Available Capacity after fourteen (14) hours before the WECC Preschedule Day, but before the CAISO deadline for submitting Schedules into the Day-Ahead Market, call primary phone (415) 973-1971 or backup phone (415) 973-4500. Also send email to DAenergy@pge.com.
 - e. For Hourly Forecasts of Available Capacity, call PG&E's Real Time Desk at (415) 973-4500 and email to RealTime@pge.com.

- f. For Planned Outages and Prolonged Outages, complete the specifics below and submit by email to MerchantOutages@pge.com, DAenergy@pge.com, ESMOutageCoordinator@pge.com, and Bilat_Settlements@pge.com.
 - i. **Email subject field: Company Name, Contract Name, Email Purpose, Date Range (For example: “dd/mm/yyyy through dd/mm/yyyy, XYZ Company Project #2, Daily Forecast of Available Capacity”)**
 - ii. **Email body:**
 - 1. **Type of Outage: Planned Outage or Prolonged Outage**
 - 2. **Start Date and Start Time**
 - 3. **Estimated or Actual End Date and End Time for Outage**
 - 4. **Date and time when reported to PG&E and name(s) of PG&E representative(s) contacted**
 - 5. **Text description of additional information as needed, including, but not limited to, changes to a Planned Outage or Prolonged Outage.**
 - 6. **Contact name: first and last name of the individual at the Unit to contact regarding the outage(s) at issue in the email.**

C. FORCED OUTAGE REPORTING

- 1. Forced Outages – Seller shall notify PG&E Merchant Generation desk verbally at (415) 973-4500 within ten (10) minutes of event or as soon as reasonably possible, after the safety of all personnel and securing of all facility equipment.
 - a. Verbal notification shall include time of forced outage, cause, current availability and estimated return date and time.
 - b. After verbally notifying PG&E Merchant Generation desk of the forced outage, Seller shall also put forth commercially reasonable efforts to notify PG&E Settlements via PG&E’s Website, as defined above.
 - c. If PG&E’s Website is unavailable, submit the following information via email to Bilat_Settlements@pge.com.
 - i. **Email subject field: Company Name, Contract Name, Email Purpose, Date Range (For example: “dd/mm/yyyy through dd/mm/yyyy, XYZ Company Project #2, Daily Forecast of Available Capacity”)**
 - ii. **Email body:**
 - 1. **Type of Outage: Forced Outage**
 - 2. **Start Date and Start Time**
 - 3. **Estimated or Actual End Date and End Time**

4. *Date and time when reported to PG&E and name(s) of PG&E representative(s) contacted.*
5. *Text description of additional information as needed.*
6. *Primary and secondary causes of Forced Outage, including a detailed description of specific equipment involved and the nature of the problem or condition.*
7. *Equipment description and nature of work being performed. For generation outages, include NERC Generation Availability Data System (GADS) numbers (as available) that identify the specific equipment and type of work that affect restrictions. Include additional equipment designations as available.*
8. *Text description of additional information as needed, including, but not limited to, changes to a previously scheduled Outage, links/cross-references to related outage cards and log entries, outage classifications per the CAISO Tariff, etc.*
9. *Associated events, e.g. operation of Special Protection Schemes.*
10. *Impact on CAISO-controlled Grid.*

APPENDIX VII

FORM OF CONSENT TO ASSIGNMENT

CONSENT AND AGREEMENT

This CONSENT AND AGREEMENT (“Consent and Agreement”) is entered into as of [_____, 2____], between PACIFIC GAS AND ELECTRIC COMPANY (“PG&E”), and [_____] , as collateral agent (in such capacity, “Financing Provider”), for the benefit of various financial institutions (collectively, the “Secured Parties”) providing financing to [_____] (“Seller”). PG&E, Seller, and the Financing Provider shall each individually be referred to as a “Party” and collectively as the “Parties”.

Recitals

A. Pursuant to that certain Power Purchase Agreement dated as of _____, 2____ (as amended, modified, supplemented or restated from time to time, as including all related agreements, instruments and documents, collectively, the “Assigned Agreement”) between PG&E and Seller, PG&E has agreed to purchase energy from Seller.

B. The Secured Parties have provided, or have agreed to provide, to Seller financing (including a financing lease) pursuant to one or more agreements (the “Financing Documents”), and require that Financing Provider be provided certain rights with respect to the “Assigned Agreement” and the “Assigned Agreement Accounts,” each as defined below, in connection with such financing.

C. In consideration for the execution and delivery of the Assigned Agreement, PG&E has agreed to enter into this Consent and Agreement for the benefit of Seller.

Agreement

1. Definitions. Any capitalized term used but not defined herein shall have the meaning specified for such term in the Assigned Agreement.

2. Consent. Subject to the terms and conditions below, PG&E consents to and approves the pledge and assignment by Seller to Financing Provider pursuant to the Loan Agreement and/or Security Agreement of (a) the Assigned Agreement, and (b) the accounts, revenues and proceeds of the Assigned Agreement (collectively, the “Assigned Agreement Accounts”).

3. Limitations on Assignment. Financing Provider acknowledges and confirms that, notwithstanding any provision to the contrary under applicable law or in any Financing Document executed by Seller, Financing Provider shall not assume, sell or otherwise dispose of the Assigned Agreement (whether by foreclosure sale, conveyance in lieu of foreclosure or otherwise) unless, on or before the date of any such assumption, sale or disposition, Financing Provider or any third party, as the case may be, assuming, purchasing or otherwise acquiring the Assigned Agreement (a) cures any and all defaults of Seller under the Assigned Agreement which are capable of being cured and which are not personal to the Seller, (b) executes and delivers to PG&E a written assumption of all of Seller’s rights and obligations under the Assigned Agreement in form and substance reasonably satisfactory to PG&E, (c) otherwise satisfies and complies with all requirements of the Assigned Agreement, (d) provides such tax and enforceability assurance as PG&E may reasonably request, and (e) is a Permitted Transferee (as defined below). Financing Provider further acknowledges that the assignment of the Assigned Agreement and the Assigned Agreement Accounts is for security purposes only and that Financing Provider has no

rights under the Assigned Agreement or the Assigned Agreement Accounts to enforce the provisions of the Assigned Agreement or the Assigned Agreement Accounts unless and until an event of default has occurred and is continuing under the Financing Documents between Seller and Financing Provider (a “Financing Default”), in which case Financing Provider shall be entitled to all of the rights and benefits and subject to all of the obligations which Seller then has or may have under the Assigned Agreement to the same extent and in the same manner as if Financing Provider were an original party to the Assigned Agreement.

“Permitted Transferee” means any person or entity who is reasonably acceptable to PG&E. Financing Provider may from time to time, following the occurrence of a Financing Default, notify PG&E in writing of the identity of a proposed transferee of the Assigned Agreement, which proposed transferee may include Financing Provider, in connection with the enforcement of Financing Provider’s rights under the Financing Documents, and PG&E shall, within thirty (30) business days of its receipt of such written notice, confirm to Financing Provider whether or not such proposed transferee is a “Permitted Transferee” (together with a written statement of the reason(s) for any negative determination) it being understood that if PG&E shall fail to so respond within such thirty (30) business day period such proposed transferee shall be deemed to be a “Permitted Transferee”.

4. Cure Rights.

(a) Notice to Financing Provider by PG&E. PG&E shall, concurrently with the delivery of any notice of an event of default under the Assigned Agreement (each, an “Event of Default”) to Seller (a “Default Notice”), provide a copy of such Default Notice to Financing Provider pursuant to Section 9(a) of this Consent and Agreement. In addition, Seller shall provide a copy of the Default Notice to Financing Provider the next business day after receipt from PG&E, independent of any agreement of PG&E to deliver such Default Notice.

(b) Cure Period Available to Financing Provider Prior to Any Termination by PG&E. Upon the occurrence of an Event of Default, subject to (i) the expiration of the relevant cure periods provided to Seller under the Assigned Agreement, and (ii) Section 4(a) above, PG&E shall not terminate the Assigned Agreement unless it or Seller provides Financing Provider with notice of the Event of Default and affords Financing Provider an Additional Cure Period (as defined below) to cure such Event of Default. For purposes of this Agreement “Additional Cure Period” means (i) with respect to a monetary default, ten (10) days in addition to the cure period (if any) provided to Seller in the Assigned Agreement, and (ii) with respect to a non-monetary default, thirty (30) days in addition to the cure period (if any) provided to Seller in the Assigned Agreement.

(c) Failure by PG&E to Deliver Default Notice. If neither PG&E nor Seller delivers a Default Notice to Financing Provider as provided in Section 4(a), the Financing Provider’s applicable cure period shall begin on the date on which notice of an Event of Default is delivered to Financing Provider by either PG&E or Seller. Except for a delay in the commencement of the cure period for Financing Provider and a delay in PG&E’s ability to terminate the Assigned Agreement (in each case only if both PG&E and Seller fail to deliver notice of an Event of Default to Financing Provider), failure of PG&E to deliver any Default Notice shall not waive PG&E’s right to take any action under the Assigned Agreement and will not subject PG&E to any damages or liability for failure to provide such notice.

(d) Extension for Foreclosure Proceedings. If possession of the Project (as defined in the Assigned Agreement) is necessary for Financing Provider to cure an Event of Default and Financing Provider commences foreclosure proceedings against Seller within thirty (30) days of receiving notice of an Event of Default from PG&E or Seller, whichever is received first, Financing Provider shall be

allowed a reasonable additional period to complete such foreclosure proceedings, such period not to exceed ninety (90) days; provided, however, that Financing Provider shall provide a written notice to PG&E that it intends to commence foreclosure proceedings with respect to Seller within ten (10) business days of receiving a notice of such Event of Default from PG&E or Seller, whichever is received first. In the event Financing Provider succeeds to Seller's interest in the Project as a result of foreclosure proceedings, the Financing Provider or a purchaser or grantee pursuant to such foreclosure shall be subject to the requirements of Section 3 of this Consent and Agreement.

5. Setoffs and Deductions. Each of Seller and Financing Provider agrees that PG&E shall have the right to set off or deduct from payments due to Seller each and every amount due PG&E from Seller whether or not arising out of or in connection with the Assigned Agreement. Financing Provider further agrees that it takes the assignment for security purposes of the Assigned Agreement and the Assigned Agreement Accounts subject to any defenses or causes of action PG&E may have against Seller.

6. No Representation or Warranty. Seller and Financing Provider each recognizes and acknowledges that PG&E makes no representation or warranty, express or implied, that Seller has any right, title, or interest in the Assigned Agreement or as to the priority of the assignment for security purposes of the Assigned Agreement or the Assigned Agreement Accounts. Financing Provider is responsible for satisfying itself as to the existence and extent of Seller's right, title, and interest in the Assigned Agreement, and Financing Provider releases PG&E from any liability resulting from the assignment for security purposes of the Assigned Agreement and the Assigned Agreement Accounts.

7. Amendment to Assigned Agreement. Financing Provider acknowledges and agrees that PG&E may agree with Seller to modify or amend the Assigned Agreement, and that PG&E is not obligated to notify Financing Provider of any such amendment or modification to the Assigned Agreement. Financing Provider hereby releases PG&E from all liability arising out of or in connection with the making of any amendment or modification to the Assigned Agreement.

8. Payments under Assigned Agreement. PG&E shall make all payments due to Seller under the Assigned Agreement from and after the date hereof to [____], as depositary agent, to ABA No. [____], Account No. [____], and Seller hereby irrevocably consents to any and all such payments being made in such manner. Each of Seller, PG&E and Financing Provider agrees that each such payment by PG&E to such depositary agent of amounts due to Seller from PG&E under the Assigned Agreement shall satisfy PG&E's corresponding payment obligation under the Assigned Agreement.

9. Miscellaneous.

(a) Notices. All notices hereunder shall be in writing and shall be deemed received (i) at the close of business of the date of receipt, if delivered by hand or by facsimile or other electronic means, or (ii) when signed for by recipient, if sent registered or certified mail, postage prepaid, provided such notice was properly addressed to the appropriate address indicated on the signature page hereof or to such other address as a party may designate by prior written notice to the other parties, at the address set forth below:

If to Financing Provider:	
Name:	
Address:	
Attn:	
Telephone:	
Facsimile:	
Email:	

If to PG&E:	
Name:	
Address:	
Attn:	
Telephone:	
Facsimile:	
Email:	

(b) No Assignment. This Consent and Agreement shall be binding upon and shall inure to the benefit of the successors and assigns of PG&E, and shall be binding on and inure to the benefit of the Financing Provider, the Secured Parties and their respective successors and permitted transferees and assigns under the loan agreement and/or security agreement.

(c) No Modification. This Consent and Agreement is neither a modification of nor an amendment to the Assigned Agreement.

(d) Choice of Law. The parties hereto agree that this Consent and Agreement shall be construed and interpreted in accordance with the laws of the State of California, excluding any choice of law rules which may direct the application of the laws of another jurisdiction.

(e) No Waiver. No term, covenant or condition hereof shall be deemed waived and no breach excused unless such waiver or excuse shall be in writing and signed by the party claimed to have so waived or excused.

(f) Counterparts. This Consent and Agreement may be executed in one or more duplicate counterparts, and when executed and delivered by all the parties listed below, shall constitute a single binding agreement.

(g) No Third Party Beneficiaries. There are no third party beneficiaries to this Consent and Agreement.

(h) Severability. The invalidity or unenforceability of any provision of this Consent and Agreement shall not affect the validity or enforceability of any other provision of this Consent and Agreement, which shall remain in full force and effect.

(i) Amendments. This Consent and Agreement may be modified, amended, or rescinded only by writing expressly referring to this Consent and Agreement and signed by all parties hereto.

IN WITNESS WHEREOF, each of PG&E and Financing Provider has duly executed this Consent and Agreement as of the date first written above.

PACIFIC GAS AND ELECTRIC COMPANY (PG&E)

By: _____
Name: _____
Title: _____

[_____]
(Financing Provider), as collateral agent

By: _____
Name: _____
Title: _____

ACKNOWLEDGEMENT

The undersigned hereby acknowledges the Consent and Agreement set forth above, makes the agreements set forth therein as applicable to Seller, including the obligation of Seller to provide a copy of any Default Notice it receives from PG&E to Financing Provider the next business day after receipt by Seller, and confirms that the Financing Provider identified above and the Secured Parties have provided or are providing financing to the undersigned.

[_____] [name of Seller]

By: _____
Name: _____
Title: _____

APPENDIX VIII

SELLER DOCUMENTATION CONDITION PRECEDENT

Seller shall provide to Buyer all of the following documentation prior to the Execution Date:

1. A copy of each of (A) the articles of incorporation, certificate of incorporation, operating agreement or similar applicable organizational document of Seller and (B) the by-laws or other similar document of Seller (collectively, “Charter Documents”) as in effect, or anticipated to be in effect, on the Execution Date.
2. A certificate signed by an authorized officer of Seller (who must be a different person than the officers listed in clause (C) below), dated no earlier than ten (10) Business Days prior to the Execution Date, certifying (A) that attached thereto is a true and complete copy of the Charter Documents of the Seller, as in effect at all times from the date on which the resolutions referred to in clause (B) below were adopted to and including the date of such certificate; (B) that attached thereto is a true and complete copy of resolutions duly adopted by the board of directors (or other equivalent body) or evidence of all corporate or limited liability company action, as the case may be, of Seller, authorizing the execution, delivery and performance of this Agreement, and that such resolutions have not been modified, rescinded or amended and are in full force and effect, and (C) as to the name, incumbency and specimen signature of each officer of Seller executing this Agreement.
3. A certificate from the jurisdiction of Seller’s incorporation or organization certifying that Seller is duly organized, validly existing and in good standing under the laws of such jurisdiction.
4. Evidence of Site control (e.g. lease with redacted price terms) satisfactory to Buyer.
5. Evidence of CEC Certification and Verification (pre-certification) satisfactory to Buyer.
6. A copy of the most recent financial statements (which may be unaudited) from Seller together with a certificate from the Chief Financial or equivalent officer of Seller, dated no earlier than ten (10) Business Days prior to the Execution Date, to the effect that, to the best of such officer’s knowledge, (A) such financial statements are true, complete and correct in all material respects and (B) there has been no material adverse change in the financial condition, operations, Properties, business or prospects of Seller since the date of such financial statements.
7. An executed Letter of Concurrence substantially in the form specified in Appendix XI.

[Appendix IX applies to As-Available Product only]

APPENDIX IX

FORM OF ACTUAL AVAILABILITY REPORT

Pursuant to Section 3.1(l)(i), Seller shall prepare an Actual Availability Report in accordance with the procedures described in this Appendix IX.

- (a) Availability Workbook. Seller shall (i) collect the measurement data, listed in (b) below, in one (1) or more Microsoft Excel Workbooks (the “Availability Workbook”) provided in a form and naming convention approved by Buyer and (ii) electronically send the Availability Workbook to an address provided by Buyer. The Actual Availability Report shall reflect the sum of the Settlement Interval Actual Available Capacity of all generators as measured by such generator’s internal turbine controller.
- (b) Log of Availability. The Availability Workbook shall be created on a single, dedicated Excel worksheet and shall be in the form of Attachment A to this Appendix IX.

APPENDIX IX

Attachment A

Form of Actual Availability Report

Seller's Actual Availability Report

All amounts are in MWs

Settlement Interval No.	Date	HE1	HE2	HE3	HE4	HE5	HE6	HE7	HE8	HE9	HE10	HE11	HE12	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23	HE24
1	mm/dd/yyyy																								
2	mm/dd/yyyy																								
3	mm/dd/yyyy																								
4	mm/dd/yyyy																								
5	mm/dd/yyyy																								
6	mm/dd/yyyy																								
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4	mm/dd/yyyy																								
5	mm/dd/yyyy																								
6	mm/dd/yyyy																								

Date/Time of Submittal

APPENDIX X

TELEMETRY PARAMETERS FOR WIND OR SOLAR FACILITY

Technology Type	Telemetry Parameters	Units
Solar Photovoltaic	Back Panel Temperature	°C
	Global Horizontal Irradiance	W/m ²
	Plane of Array Irradiance (If PV is fixed)	W/m ²
	Direct Normal Irradiance (If PV is Tracking)	
	Wind Speed	m/s
	Peak Wind Speed (Within 1 minute)	m/s
	Wind Direction	Degrees
	Ambient Air Temperature	°C
	Dewpoint Air Temperature or Relative Humidity	°C
	Horizontal Visibility	m
	Precipitation (Rain Rate)	mm/hr
	Precipitation (Running 30 day total)	mm
	Barometric Pressure	Millibars or Hecto Pascals (HPa)
Solar Thermal or Solar Trough	Global Horizontal Irradiance	W/m ²
	Plane of Array Irradiance (If PV is fixed)	W/m ²
	Direct Normal Irradiance (If PV is Tracking)	
	Wind Speed	m/s
	Peak Wind Speed (Within 1 minute)	m/s
	Wind Direction	Degrees
	Ambient Air Temperature	°C
	Dewpoint Air Temperature or Relative Humidity	°C
	Horizontal Visibility	m
	Precipitation (Rain Rate)	mm/hr
	Precipitation (Running 30 day total)	mm
	Barometric Pressure	Millibars or Hecto Pascals (HPa)
	Individual Tracking Assembly Angle Set Points (Solar Trackers Only)	Degrees
	Actual Tracking Assembly Angles (Solar Trackers Only)	Degrees
Wind	Wind Speed (measured at hub height)	m/s
	Peak Wind Speed (Within 1 minute, measured at hub height)	m/s
	Wind Direction	Degrees
	Wind Speed Standard Deviation	--
	Wind Direction Standard Deviation	--
	Barometric Pressure (measured at hub height)	Millibars or Hecto Pascals (HPa)
	Ambient Temperature (measured at hub height)	°C

APPENDIX XI

FORM OF LETTER OF CONCURRENCE

[Date]

[Name]

[Position]

[Company]

[Address]

Re: Letter of Concurrence Regarding Control of [Name] Facility

This letter sets forth the understanding of the degree of control exercised by Pacific Gas and Electric Company (“PG&E”) and [Company Name] with respect to [Facility Name (the “Facility”)] for the purposes of facilitating compliance with the requirements of the Federal Energy Regulatory Commission’s (“Commission”) Order No. 697.¹ Specifically, Order No. 697 requires that sellers filing an application for market-based rates, an updated market power analysis, or a required change in status report with regard to generation specify the party or parties they believe have control of the generation facility and extent to which each party holds control.² The Commission further requires that “a seller making such an affirmative statement seek a ‘letter of concurrence’ from other affected parties identifying the degree to which each party controls a facility and submit these letters with its filing.”³

PG&E and [Company Name] have executed a [power purchase and sale agreement (the “Agreement”)] with regard to the Facility. The Facility is a [XX] MW [description] facility located in [County, State]. Pursuant to the Agreement, [Company Name] maintains sole control of the Facility. [Company Name] agrees to provide subsequent Letters of Concurrence as may be necessary should any of the information provided herein change after the execution date of this letter.

If you concur with the statements made in this letter, please countersign the letter and send a copy to me.

Best regards,

[Author]

[Position]

Pacific Gas and Electric Company

¹ *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697 at P 186-187, FERC Stats. & Regs. ¶ 31,252, *clarified*, 121 FERC ¶ 61,260 (2007), *order on reh’g*, Order No. 697-A, FERC Stats. & Regs. ¶ 31,268 (2008), *clarified*, 124 FERC ¶ 61,055 (2008), *order on reh’g*, Order No. 697-B, FERC Stats. & Regs. ¶ 31,285 (2008), *order on reh’g*, Order No. 697-C, FERC Stats. & Regs. ¶ 31,291 (2009), *order on reh’g*, Order No. 697-D, FERC Stats. & Regs. ¶ 31,305 (2010).

² Order No. 697 at P 186.

³ Order No. 697 at P 187.

Concurring Statement

On behalf of [Company Name], I am authorized to countersign this letter in concurrence with its content.

By: _____

[Name]

[Company Position]

[Company Name]

APPENDIX XII

SUPPLIER DIVERSITY PROGRAM

1. Seller shall provide Women-, Minority-, and service Disabled Veteran-, and Lesbian, Gay, Bisexual and/or Transgender-owned Business Enterprises, as verified pursuant to the procedures prescribed in Section 2 of CPUC General Order 156 (“WMDVLBE”), the maximum practicable opportunity to participate in the performance of work supporting Seller’s construction, operation, and maintenance of the Project. General Order 156 can be found on <http://www.cpuc.ca.gov/puc/documents/go.htm>.
2. Upon request from Buyer, Seller shall provide a separate “Supplier Plan” consisting of a specific list of suppliers that may participate in the performance of the work supporting the construction of the Project prior to the Commercial Operation Date and operation and maintenance of the Project after the Initial Energy Delivery Date, and a statement setting forth any additional efforts Seller will employ to increase the participation of WMDVLBE suppliers supporting the construction, operation and maintenance of the Project.
3. Upon request from Buyer, but no less than once per 365 day period of time between the Execution Date and the end of the Delivery Term, Seller shall report its spending with WMDVLBE suppliers per instructions to be provided by PG&E.
4. Targets.
 - a) Seller’s supplier diversity spending target for Work supporting the construction of the Project prior to the Commercial Operation Date is ____ percent (____%) as measured relative to Seller’s total expenditures on construction of the Project prior to the Commercial Operation Date, and;
 - b) Seller’s annual supplier diversity spending target for Work supporting the operation and maintenance of the Project after the Initial Energy Delivery Date is ____percent (____%) as measured relative to the net payments made by Buyer to Seller in each Contract Year.
5. Seller shall use good faith efforts in meeting the requirements of this Appendix XII which efforts shall be material obligations.

[Bracketed language applicable to WMDVLBE Sellers only]

6. Seller is a WMDVLBE, as certified by _____ [please identify the certifying agency].

APPENDIX XIII
PROJECT SPECIFICATIONS AND CONTRACT CAPACITY CALCULATION

I. PROJECT SPECIFICATIONS

“MVA” means megavolt ampere, the unit of apparent power.

“Nameplate Rated Output” means, with respect to an inverter or electric generator, the MVA that the manufacturer of the inverter or generator has designed such equipment to produce under normal operating conditions as specified by such manufacturer.

“Designated Power Factor” means, with respect to an inverter or electric generator, the power factor required to satisfy the portion of the Project’s reactive power requirements that are specified in *[please identify the applicable source, such as the PTO’s Interconnection Handbook, the CAISO’s Phase II Study, or the Generator Interconnection Agreement for the Project]* and are not being satisfied by other sources of reactive power within the Project.

“Nameplate Rated Power” means, with respect to an inverter or electric generator, the multiplication product of the Nameplate Rated Output and the Designated Power Factor for such inverter or generator, in MWs.

The project specifications shall consist of the following eleven (11) items (each item of which shall be a “Project Specification”). As provided in Section 3.1(g), Seller shall not make any change or modification to any Project Specification without Buyer’s prior written consent.

1. Project name:
2. Project Site name:
3. Project physical address:
4. Total number of Units at the Project:
5. Technology Type:
6. Interconnection Point of Project:
7. Service Territory of Project:
8. Substation:
9. Description of Units: *[delete inapplicable project types]*

• **For a Solar PV Project**

- a. For each type of inverter in the Project, specify in the table below the type, the number of inverters, the Nameplate Rated Output, the total Nameplate Rated Output, the Designated Power Factor, the Nameplate Rated Power and the total Nameplate Rated Power: *[add rows as needed]*

Inverter Type	Number of Inverters	Nameplate Rated Output (MVA)		Designated Power Factor	Nameplate Rated Power (MW)	
		Per Inverter	Total		Per Inverter	Total
Total		N/A			N/A	

- b. For each type of panel technology (e.g., multi-crystalline silicon, mono-crystalline silicon, thin-film CdTe, multi-junction, bifacial, concentrating, etc.) and each type of panel orientation (e.g., fixed-mount, tilt-angle, azimuth, single-axis tracker, double axis tracker, etc.) specify in the table below the technology, the type of orientation and the total DC rating at Standard Test Conditions: *[add rows as needed]*

Panel Technology	Orientation	DC Rating at STC (MW _{DC})
Total	N/A	

“Standard Test Conditions” means, with respect to determining the nameplate DC rating of a solar PV panel in a factory flash test, an irradiance of 1,000 W/m², a panel temperature of 25°C, and an air mass of 1.5.

- **For a Solar Thermal Project**

- Specify the total area (square meters) of solar mirrors (or of apertures for parabolic mirrors):
- Specify the technology (e.g., parabolic trough, power tower, parabolic disk) and the storage medium and capacity, etc.:
- For each steam turbine, specify the rated conditions (MW rating, steam inlet temperature, steam inlet pressure, condensing temperature, mass flow rate):
- For each electric generator, specify the Nameplate Rated Output, Designated Power Factor and Nameplate Rated Power:

- **For a Wind Project**

For each type of turbine, specify the Nameplate Rated Output, Designated Power Factor and Nameplate Rated Power and the rated output wind speed (m/s):

- **For a Biomass or Geothermal Steam Project**

- For each steam turbine, specify the rated conditions (MW rating, steam inlet temperature, steam inlet pressure, condensing temperature, mass flow rate):
- For each electric generator, specify the Nameplate Rated Output, Designated Power Factor and Nameplate Rated Power:

10. Description of Land:

The Site contains the following Assessor Parcel Numbers upon which the Project is located and as identified on the topographical map included in this Appendix XIII: [Insert Map]

11. Description of Interconnection Facilities and metering:

The Project will use the following Interconnection Facilities and metering configuration as identified in this one-line diagram included in this Appendix XIII:

[Insert One-Line Diagram for Interconnection Facilities and Metering]

12. Maps: The Site is identified in the following topographical map:

[INSERT MAP]

II. CONTRACT CAPACITY CALCULATION

The Contract Capacity specified in Section B of the Cover Sheet shall be the factor (A) minus each of the factors (B) through (E) provided below:

A	Sum of the Nameplate Rated Power of all inverters/generators	_____ MW
B	Calculated electrical losses from inverter/generator output terminals to Delivery Point (with all inverters/generators operating at Nameplate Rated Outputs)	_____ MW
C	Electrical Losses	_____ MW
D	Auxiliary and station loads coincident with inverters/generators operating at Nameplate Rated Outputs	_____ MW
E	Other factors (explain below)	_____ MW
F	Contract Capacity at the Delivery Point ($F = A - B - C - D - E$), which shall be the same as the MW amount specified for the Contract Capacity in Section B of the Cover Sheet	_____ MW

Inputs for the Nameplate Rated Power calculation:

Designated Power Factor:

	Leading	Lagging
Project power factor requirements	_____	_____
Seller's Designated Power Factor for inverters/generators	_____	_____

Power factor requirement is measured at (check one):

☐ inverter/generator terminals; ☐ Point of Interconnection; ☐ Other: _____

APPENDIX XIV

SECTION 3.3(e) LIQUIDATED DAMAGES CALCULATION

I. Equation and Formulas for Calculating RA Deficiency Amount

As provided in Section 3.3(e)(ii)(B), the formula for calculating the RA Deficiency Amount in a given RA Shortfall Month is:

$$\text{RA Deficiency Amount (\$/Month)} = \text{RA Value (\$/MW/Month)} \times \text{Expected Net Qualifying Capacity (MW)}$$

Where the:

- A. RA Value shall be \$4,010/MW/Month in calendar year 2016 and shall escalate at 2.5% per year for each succeeding calendar year; and
- B. Expected Net Qualifying Capacity for projects that selected Full Capacity Deliverability Status shall be the product of the Contract Capacity and the applicable monthly Qualifying Capacity factor in the table below; or
- C. Expected Net Qualifying Capacity for Projects seeking Partial Capacity Deliverability Status shall be the minimum of (a) the Expected Net Qualifying Capacity values as calculated in Section B above; or, (b) the product of the Contract Capacity and the Partial Capacity Deliverability Status Amount.

Table XIV-1 Monthly Qualifying Capacity Factor

Month	Biomass	Geothermal	Solar	Wind
Jan	70.61%	84.92%	0.79%	4.43%
Feb	72.50%	85.34%	6.62%	8.25%
March	70.79%	82.42%	15.12%	21.36%
April	62.13%	80.44%	60.43%	23.90%
May	65.57%	81.99%	64.13%	31.04%
June	73.55%	78.59%	80.03%	27.31%
July	76.32%	78.74%	80.39%	17.04%
Aug	75.31%	78.37%	74.86%	15.31%
Sept	74.67%	78.78%	73.05%	9.20%
Oct	71.80%	79.05%	48.29%	7.22%
Nov	70.86%	81.08%	2.49%	4.43%
Dec	74.25%	83.15%	1.33%	4.50%

II. Example of Calculation of the RA Deficiency Amount (for illustrative purposes only) if:

- RA Shortfall Month is June 2019
- Project is a solar system
- Contract Capacity is 20 MW
- RA Start Date is based on the Expected FCDS Date, which is January 1, 2019
- FCDS is achieved on August 14, 2019

RA Value (\$/MW/Month) = \$4,010.00, escalated at 2.5% per year for 3 years, from 2016 to 2019

$$\$4,010 \times (1.025)^3 = \$4,318/\text{MW/Month}.$$

Monthly Qualifying Capacity factor for a solar project in June is 86.74% (from table above).

Expected Net Qualifying Capacity =

$$\text{Contract Capacity (MW)} \times \text{monthly Qualifying Capacity factor} =$$

$$20 \text{ MW} \times 86.74\% = 17.35 \text{ MW}$$

RA Deficiency Amount (\$/Month) =

$$\text{RA Value ($/MW/Month)} \times \text{Expected Net Qualifying Capacity (MW)} =$$

$$\$4,318/\text{MW/Month} \times 17.35 \text{ MW} = \$74,917.30$$

In this example, the RA Shortfall Period is from January through October 2019. The calculations above would be performed and the result applied for each month in this RA Shortfall Period.

Confidential Appendix E

Independent Evaluator Report (Redacted version)

**REPORT OF THE INDEPENDENT EVALUATOR REGARDING
PACIFIC GAS & ELECTRIC'S SIXTH RENEWABLE AUCTION MECHANISM
REQUEST FOR OFFERS**

**PRESENTED TO
CALIFORNIA PUBLIC UTILITIES COMMISSION
ENERGY DIVISION**

by

BOSTON PACIFIC COMPANY, INC.

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January 14, 2016

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II.	INDEPENDENT EVALUATOR CHECKLIST	5

ATTACHMENTS

I. EXECUTIVE SUMMARY

Pacific Gas & Electric (PG&E) is submitting for approval a set of Power Purchase Agreements (PPAs) resulting from its Sixth Renewable Auction Mechanism Request for Offers (RAM VI RFO or RFO). Boston Pacific Company, Inc. (Boston Pacific) served as the Independent Evaluator (IE) charged with overseeing this procurement.

The RAM program was established under California Public Utilities Commission (CPUC) Decision 10-12-048 in December 2010 with the goal of procuring statewide up to 1,000 MW of supply from smaller-scale renewable energy projects that are eligible for the California Renewable Portfolio Standard (RPS) program over a three-year period. PG&E has since conducted five RAM solicitations. This RAM solicitation was governed by the CPUC Decision 14-11-042 on Renewables Portfolio Standard Procurement Plans as modified by PG&E's Advice Letter 4605-E. Projects could range in size from greater than 3 MW to 20 MW (with some exceptions as noted below). Bidders offered their projects as energy-only, full or partial-capacity deliverability (i.e., energy plus capacity) for PPAs of 10, 15 or 20 years in length. Because all bids signed the same standardized PPA, the evaluation of winning offers was based primarily on an all-in price, which reflected transmission upgrade costs and Resource Adequacy benefits.

This procurement differed from past RAM solicitations because it incorporated procurements for two additional programs. First, per its February 2014 petition¹ PG&E was allowed to close its Solar Photovoltaic (PV) Program and procure the remaining targeted capacity under that program via other mechanisms. The Solar PV program sought the same resources that are procured in the RAM RFO, with the exception being that RAM projects may be of several different technology types rather than just solar PV. PG&E was directed to procure half of its remaining Solar PV targets via this year's RAM solicitation.² When combined with the RAM VI RFO targets, this produced a total target of 137 MW of renewable supply in three categories, Baseload, As-Available Peaking (Peaking), and As-Available Non-Peaking (Non-Peaking).

The second program included in this year's solicitation was the Green Tariff Shared Renewables (GTSR) Program – also known as the PG&E Solar Choice (PSC) Program.³ This program was established by Senate Bill 43 as a statewide program with the goal of expanding access to renewable resources and allowing customers to purchase up to 100 percent of their electricity from such resources. The program set a statewide procurement target of 600 MW of renewable resources. PG&E sought to procure 50 MW of GTSR projects in this RFO, in

¹ Petition for Expedited Order Granting Modification of D.10-04-052 (Photovoltaic Program) and Approval of a Proposed Schedule for the Third Photovoltaic Program Power Purchase Agreement Solicitation. February 26, 2014.

² PG&E ultimately targeted 105 MW for the Solar PV Program from this solicitation.

³ PSC is PG&E's brand name for the program.

addition to its RAM and Solar PV Program requirements. GTSR projects had to be new, solar powered, between 0.5 MW to 20 MW in size and located within PG&E's service territory. Within this 50 MW target, PG&E also sought sub-categories of GTSR projects located in specific areas –designated as Environmental Justice (EJ) and Community Projects – in order to meet other requirements of Senate Bill 43 and internal PG&E goals.

Ultimately, thirteen offers were selected and signed PPAs for the three programs. These are, for the RAM program:

- GASNA 6P, LLC (“San Joaquin 1A”), a 20 MW solar photovoltaic-powered project from Solar Frontier Americas Development, LLC, located in PG&E's service territory in Fresno County, and offering a 20 year contract.

For the Solar PV Program:

- Java Solar Project, a 13.5 MW solar photovoltaic-powered project from SunPower Corporation, located in PG&E's service territory in Kings County and offering a 20 year contract.
- Bayshore Solar A, B and C, three 20 MW solar photovoltaic-powered projects from Sustainable Power Group, located in Southern California Edison's service territory in Los Angeles County, and offering 20 year contracts. While all these projects are on contiguous tracts of land they will meet the RFO requirements to have separate metering. Note that there is no prohibition in this procurement against this sort of “daisy-chaining” of projects.

For the GTSR Program (note that all projects are located in PG&E's service territory):

- Merced 1, a 3 MW solar photovoltaic-powered project from Green Light Energy Corp., located in Merced County, and offering a 20 year contract.
- GASNA36P, LLC (“San Joaquin 1B FIT”), a 1.5 MW solar photovoltaic-powered project from Solar Frontier Americas Development, LLC, located in Fresno County, and offering a 20 year contract.
- 54KR, a 20 MW solar photovoltaic-powered project from 8minutenergy Renewables, LLC, located in Kern County, and offering a 20 year contract.
- Tranquility 8 Amarillo, a 20 MW solar photovoltaic-powered project from Recurrent Energy, located in Fresno County, and offering a 20 year contract.
- Bakersfield 1, a 5.25 MW solar photovoltaic-powered project from Mirasol Development, LLC, located in Kern County, and offering a 20 year contract.

- Bakersfield Industrial 1, a 1 MW solar photovoltaic-powered project from Mirasol Development, LLC, located in Kern County, and offering a 20 year contract.
- Delano Land 1, a 1 MW solar photovoltaic-powered project from Mirasol Development, LLC, located in Kern County, and offering a 20 year contract.
- Manteca Land 1, a 1 MW solar photovoltaic-powered project from Mirasol Development, LLC, located in San Joaquin County, and offering a 20 year contract.

Boston Pacific recommends that the CPUC approve these contracts. We say so for four reasons. First, the procurement process was open, fair, and transparent. Because all bidders signed essentially the same contract, the evaluation of offers was based primarily on price. A price-only or price-mostly evaluation is the most transparent form of evaluation. Moreover, Boston Pacific was able to independently review and evaluate every offer made in response to the RFO. We compared our ranking of offers to PG&E's evaluations and were able to come to general agreement on the ranking of top bids, selection of initial and final portfolios and bid costs. Boston Pacific was also able to participate in phone calls between parties and review both contract documents and e-mails between parties.

Second, the RFO was competitive. In total, the RFO received offers from 19 bidders. These bidders made a total of 90 individual offers from 48 projects. For every MW needed, the RFO attracted about 3.3 times that amount. This is down quite a bit from last year's RAM V RFO - which saw 11 MW bid for each MW needed and 103 offers from 69 projects and 25 bidders – but still acceptable. This response gives us confidence that the winning offers were reasonable given current market conditions.

Third, the prices for the winning bids are consistent with market conditions. Using PG&E's estimates of total bid cost we calculate the MW-weighted-average levelized cost of the winning RAM and Solar PV bids to be \$[REDACTED]/MWh. This is almost exactly the same as the winning offers from last year's RAM RFO, which had an average cost of \$[REDACTED]/MWh and roughly in line with other publically-available PPA price data.

The GTSR projects included smaller facilities that would be expected to have higher costs given the economies of scale in constructing solar PV facilities and the restrictions on project location. Moreover, PG&E prioritized the selection of RAM and Solar PV projects in order to fulfill the requirement that regular ratepayers be indifferent to GTSR project selection. Using PG&E's calculations of total bid cost we calculate the MW-weighted-average levelized cost of the winning GTSR offers as \$[REDACTED]/MWh. This is similar to the average cost of the final signed contracts from the RAM IV RFO, which was \$[REDACTED]/MWh.

Fourth, all the RFO rules and regulations were appropriately followed. PG&E will procure 52.75 MW of supply for the GTSR Program, just a bit above the 50 MW target for the solicitation. For the RAM and Solar PV programs PG&E will only procure 93.5 MW, well short of their 137 MW target. This is mainly due to the fact that one 20 MW project dropped out of the process very recently, long after bidders had been notified of selections and released from their obligations, making it impractical to select a replacement.

PG&E's selections in each product category are roughly consistent with its discretion as laid out in the RFO.⁴ The qualification and evaluation of offers was done according to RFO rules. The signing of final agreements was done fairly and, consistent with RFO rules, there was no negotiation of PPA terms. We will note that PG&E had the option to procure additional (non-solar) supply for the RAM program and did not, which was reasonable given the cost of that supply and the fact that PG&E is projected to meet and exceed its RPS compliance requirements in the near term.

We have three observations from this procurement. First, as we explain in detail later, PG&E treated the selection of RAM projects as separate and distinct from Solar PV projects despite the fact that the projects are paid for by the same group of ratepayers. This had no effect on the final selection of bids, but it did lead PG&E to make an initial selection of bids that was slightly more expensive than, and not as diverse as, it could have been. In the future we would recommend that PG&E optimize the selection of RAM and Solar PV together rather than treating them as separate targets.

Second, as noted above, three of the winning projects are projects on a contiguous piece of land. Several other offers in this RFO exhibited similar characteristics. There is no restriction against the "daisy chaining" of projects in this RFO. However, in other procedures, for example the Renewable Market Adjusting Tariff (Re-MAT) process, the Commission has put in place prohibitions against this type of offer. If the Commission feels that this offer structure is inconsistent with the goals of the RAM program they should enact similar restrictions going forward – though we caution that this may reduce the total amount of supply offered in future RAM RFOs.

Finally, solar-photovoltaic powered systems continue to dominate the offerings in this RFO process – all the winning bids here used solar PV technology.⁵ This is to be expected due to California's solar resources and market price trends. However, the side effect is that other types of renewable resources are less competitive in these open procurements. If the Commission feels like the California utilities require more diversity in terms of renewable

⁴ Technically, per the RFO protocol, the lowest amount of supply PG&E could have taken from the RAM/Solar PV category was 95 MW. Again, PG&E was on track to meet this requirement when a project dropped out at the last minute, too late in the process to secure a replacement.

⁵ PG&E did extend one offer to a landfill gas project, although the project rejected the offer.

resources, they may want to consider a separate procurement or procurements targeted directly for those types of resources.

II. INDEPENDENT EVALUATOR CHECKLIST

1. Role of the IE

- a. Cite CPUC decisions requiring IE participation in RPS solicitations: D.04-12-048 (Findings of Fact 94-95, Ordering Paragraph 28) and D.06-05-039 (Finding of Fact 20, Conclusion of Law 3, Ordering Paragraph 8).*
- b. Description of key IE roles: IEs provide an independent evaluation of the IOU's RPS offer evaluation and selection process:*
 - 1. Did the IOU do adequate outreach to potential participants and was the solicitation robust?*
 - 2. Was the IOU's LCBF methodology designed such that all offers were fairly evaluated?*
 - 3. Was the IOU's LCBF offer evaluation and selection process fairly administered?*
 - 4. Did the IOU make reasonable and consistent choices regarding which offers were brought to CPUC for approval?*
- c. Description of activities undertaken by the IE to fulfill the IE's role (i.e. attended negotiation meetings, reviewed Request for Proposals materials, attended pre-offer conference, evaluated proposals and/or reviewed evaluation process and results, etc.) and reporting/consultation with CPUC, PRG, and others*
- d. Any other relevant information or observations*

CPUC decisions D. 04-12-048 and D.06-05-039 lay out some basic principles regarding the role of the IE. Among other things, these decisions note that the IE report can serve to “increase the fairness and equity in the bid and selection process, provide the Commission the opportunity to review the use of judgment by the IOUs in the process, increase the transparency of the process, and allow the Commission to take corrective action if necessary...”⁶ Boston Pacific served as the IE for the RAM V RFO and was approved to act as the IE for this procurement on or around December 8, 2014. The RAM VI RFO was issued to the market on July 7, 2015.

⁶ CPUC Decision D.06-05-039, Findings of Fact 20.

The role of the IE is to serve as an independent check on the utility's implementation of the RFO process and bid evaluation. The goal is to assure both bidders and the Commission that the RFO was conducted fairly in accordance with all rules and guidelines and that any offers selected from the RFO process are the best choices for ratepayers in terms of price, risk and Commission goals for the procurement.

In order to accomplish these goals the IE must review and assess bidder outreach, evaluation methodologies, bid qualification, bid scoring and selection of winning bidders and subsequent contract executions to ensure that all bidders were treated fairly, that all choices were reasonable and that the procurement generated the best possible result for ratepayers.

To carry out our evaluation we performed several actions. We reviewed all documents related to the RAM VI RFO. This included not only the RFO document itself but also the approved PPA and Commission decisions regarding the RAM process, including information related to the Solar PV and GTSR programs. We reviewed all offers made into the RFO and monitored contact between PG&E and bidders, including the bidders conference, e-mail correspondence, and phone calls between the parties. We independently reviewed, qualified, and scored each offer made into the RFO and ranked those offers according to RFO rules. We compared our evaluations against PG&E's to ensure that bids were being ranked fairly and that we had general agreement on bid costs. We worked with PG&E personnel to select an initial set of bids for contract offers and a waitlist that all parties could agree on. We then monitored the acceptance or rejection of PPA offers and PG&E's use of the waitlist to fill any shortfall in need.

Separate from our evaluation, PG&E used a similar process to evaluate offers. Because the RFO was fairly clear on qualification requirements and the method of ranking bids, our bid evaluation processes were fairly similar, though PG&E's cost evaluation models were slightly more detailed. As noted above, we checked in regularly with PG&E personnel to ensure that bids were being ranked fairly and to discuss major decisions such as construction of initial and final recommended portfolios. PG&E personnel were available to share their own evaluation methods and results and discuss all matters related to the RFO. We found PG&E personnel to be very helpful and accommodating in all these tasks.

2. IOU Outreach

- a. Were the solicitation materials clear and concise to ensure that the information required by the utility to conduct its evaluation was provided by the participants?*
- b. Did the IOUs seek adequate feedback about the offers/offer evaluation process from all participants after the solicitation was complete?*
- c. Any other relevant information or observations*

Solicitation materials were posted on a public website. The website contained a) the RFO document and all appendices, b) a schedule for the RFO process, c) information on distribution and transmission interconnection, d) instructions for using the Power Advocate submission platform, e) frequently asked questions, and f) contact information. Boston Pacific was provided access to the Power Advocate bid submission platform so that we could see and review all documents submitted by bidders.

PG&E notified over 2,900 market participants (from PG&E's normal distribution list) when the RAM VI RFO was launched on July 7, 2015. In addition, PG&E notified over 3,200 individuals from a list provided by PG&E's California Solar Initiative team to garner interest from developers for our community and environmental justice project buckets. Notifications provided links to the RFO website and information regarding the pre-bid conference.

On July 14th, PG&E held an on-line pre-bid conference for interested parties. PG&E presented details regarding the bidding opportunity, the incorporation of the Solar PV and GTSR programs, RFO schedule, eligibility requirements, procurement targets, an overview of the PPA, the evaluation methodology, bid submittal process, and interconnection information. The presentation, along with an audio recording of the discussion, Q&A (including Q&A from past RAM RFOs), and an attendee list, was posted on the RFO website. A total of 61 people, representing 43 potential bidders, attended the pre-bid conference.

Potential bidders could submit additional questions through a designated e-mail address. Boston Pacific reviewed the questions asked by bidders, as well as answers from PG&E, to ensure they were accurate and there was no evidence of widespread bidder confusion.

Offers were due on August 21, 2015. Bidders had to submit a fully completed RFO Offer form, a completed PPA cover sheet and PPA Appendix XIII (both of which provided details about the project for inclusion in the PPA), a site control questionnaire and attestation, a notice of acknowledgment and commitment of the site owners (for projects 5 MW or smaller), a project single-line diagram and the most recent interconnection studies.

The response to the RFO for all programs (RAM, Solar PV and GTSR) is shown in Table One.

TABLE ONE
RFO PARTICIPATION – ALL PROJECTS BY TECHNOLOGY CATEGORY

Category	Target MW	MW Bid	MW Bid/Target	Total Offers	Total Projects	Number of Bidders	Average Price
Baseload	10	6.0	0.6	2	1	1	
As-Available Peaking	165	565.3	3.4	83	44	17	
As-Available Non-Peaking	12	51.8	4.3	5	3	2	
Total	187	623.1	3.3	90	48	19	

In total, the RFO received 90 separate offers from 48 projects and 19 bidders. In total for every MW needed the RFO saw about 3.3 MW bid. As can be seen from the table above, the As-Available Peaking Category received the majority of the offers. This category is primarily for solar photovoltaic powered resources. This is not surprising, as this procurement sought GTSR and Solar PV Program resources and, therefore, targeted mainly solar-powered resources. The target for non-solar resources was only 22 MW. While the turnout for the Non-Peaking category was reasonable, the Baseload category only attracted a single project. The latter fact is somewhat expected. As noted in our report for the RAM V RFO, this category was not very cost-competitive and PG&E has not recently accepted any offers in this category.

The response overall was reasonable, though not nearly as robust as last year. The RAM V RFO saw a similar number of offers (103 total) but more unique projects offered (69) and, as a consequence, a larger quantity of MW offered (1,129). Most of those offers, projects and MW came from the Peaking category. While that category saw a reasonable response this year, there was clearly a decline in the number of larger solar projects offered. This could be a sign of market saturation for larger solar projects and/or a response to the potential expiration of federal solar incentives. Another factor could be that, by including the GTSR procurement in the RAM procurement, the Commission incentivized bidders to offer only where their project would be located (since this allows them to qualify for both programs). We would need to review procurement data for all utilities to confirm this theory, but we can say that this year's offers for PG&E were primarily located in PG&E's territory, whereas over half of the Peaking MW offered in RAM V were located in SCE's territory.

Another way to view the response is to see how much supply was provided to each program. Table Two below shows the participation by program.

TABLE TWO
RFO PARTICIPATION – ALL PROJECTS BY PROGRAM

Program	MW Bid	Total Offers	Total Projects	Number of Bidders	Average Price
RAM Only	57.8	7	4	3	
RAM/Solar PV Only	138.0	9	7	4	
RAM/Solar PV/GTSR	404.6	48	24	9	
GTSR Only	22.7	26	13	8	
Total	623.1	90	48	19	

As can be seen from the above table the majority of offers were qualified for all programs, meaning they were new solar powered resources located in PG&E's territory and larger than 3 MW. The next largest category was RAM and Solar PV, essentially solar projects located outside of PG&E's service territory. The third largest category was RAM Only projects, which were non solar-powered renewable projects. The GTSR-only category saw a strong number of offers but since the offers in this category were primarily under 3 MW, not a large amount of total MW offered. This was also the highest priced category, on average, due to the economies of scale seen in constructing larger solar arrays.

A more detailed way to view the results is by looking at the GTSR response alone, including the offers in each sub-category. In this RFO, PG&E had two sub-categories of GTSR projects meant to address different initiatives. The Environmental Justice category addressed SB 43's reservation of 100 MW of the total GTSR procurement for "facilities that are no larger than one megawatt nameplate rated generating capacity and that are located in areas previously identified by the California Environmental Protection Agency as the most impacted and disadvantaged communities."⁷ The second, the Community Project category, was created by PG&E in an effort to try to get projects close to load. In each case projects had to be located in designated areas in PG&E's territory to be eligible and EJ projects had to be 1 MW or less. Table Three shows the response in each category.

⁷ SB 43 2833.D.1.

TABLE THREE
GTSR RESPONSE BY CATEGORY⁸

Category	MW Bid	Total Offers	Total Projects	Number of Bidders	Average Price
GTSR "Base" Projects	409.2	51	28	12	
Enviromental Justice Projects	4.8	11	5	3	
Community Solar Projects	14.3	15	5	3	
All GTSR Projects	427.3	74	37	15	

The “Base” category saw the most offers. These were new solar photovoltaic projects located in PG&E’s service territory. These were less expensive than the offers in the two sub-categories because those categories targeted smaller projects and required locating in specific areas.

In our opinion, the response received speaks to the effectiveness of the bidder outreach as well as the clarity of the bidding documents and presentations. Because this iteration of the RAM RFO sought participation from new, smaller, bidders there was a need for more explanation of the process. Based on our review of the documents and contact with bidders we believe that PG&E did an acceptable job in answering questions for all participants.

To our knowledge PG&E has not sought feedback about the offers or evaluation process for this RFO. We would encourage them to do so at an appropriate time, particularly for the smaller GTSR participants for whom this may have been the first encounter with the RAM process.

3. IOU’s LCBF Methodology

- a. *Identify the principles the IE used to evaluate the IOU's offer evaluation methodology.*
- b. *Using the principles identified in section III.A, evaluate the strengths and weaknesses of IOU's methodology in this solicitation:*
 1. *Evaluation of consistency with RPS procurement plan, requested products, and portfolio fit. Did the IOU adequately incorporate*

⁸ Note that one project (Bakersfield Industrial 1) submitted options that counted as both a Community and an EJ project, so category totals do not match overall totals.

needs and preferences stated and approved in RPS procurement plan and protocol? For instance, did the IOU account for contract start dates, contract lengths, and varying generation amounts? Did the IOU adequately take into account a project's characteristics related to portfolio fit preferences?

- 2. Market valuation. Were both price and value taken into consideration when projects were shortlisted? Did the IOU adequately take into consideration all financial benefits and costs of a project when determining the value of projects that were shortlisted? Did the IOU include the cost of transmission upgrades in the value calculation of projects that were shortlisted? In your opinion, were any costs or benefits that should have been included in the IOU's LCBF calculation not included?*
- 3. Evaluation of offers' transmission costs. Did the IOU rely more on TRCR studies than Phase I or Phase II studies to ascertain transmission costs? Did the IOU weigh the total cost of transmission upgrades for a project against the relative value in resource adequacy that the transmission upgrade will provide for each project? Did the IOU perform any data conformance checks related to transmission study results and cost information for projects before they were included on the shortlist?*
- 4. Evaluation of offers' project viability. Did the IOU (or IE or developer) reasonably measure the viability of each project in the offer evaluation process? Did the IOU perform conformance checks related to the accuracy of the projects' viability scores before the projects were included on the shortlist?*
- 5. Other*
 - c. What future LCBF improvements would you recommend?*
 - d. Any additional information or observations regarding the IOU's evaluation methodology (e.g. capacity valuation, congestion cost adder, etc.)*

Generally speaking, when we review an evaluation methodology we are looking for a number of things. We want it to be fair, and treat all bidders, including utility affiliates, the same. We want it to be transparent so that bidders will understand just what they need to do to win. We like to see a methodology that is “price only” or “price mostly” to increase transparency and reduce the chance of selection solely by purely subjective criteria. We also like to see a methodology that recognizes risk and uncertainty inherent in the future and rewards bids that manage those risks. Finally, we like to see a methodology that is geared to produce results that are aligned with regulatory policy goals.

The evaluation process in the RAM VI RFO is fairly well aligned with these guidelines. In particular it utilized a price-based evaluation. All bidders signed the same PPA so the selection of bids was based almost solely on price. Bidders provided a price per MWh for energy from the project. The only other factors included in the bid costs were a) charges for reliability and deliverability network upgrades, which came from the bidder's own interconnection studies and b) for bids which offered capacity deliverability, a credit based on the bid's technology, location, and PG&E's forecast of avoided capacity cost. While PG&E did not provide bidders with this forecast they did note that it was higher for projects located in the NP15 area.

The only factor other than price which was considered was bid category. In the RFO, PG&E established target quantities for each product category, as shown in Table One, which includes a sub-target for the GTSR program. These targets were based on CPUC Orders. Per RFO rule PG&E was generally allowed to deviate from these targets by plus or minus 20 MW in each category.

We believe the process worked well in terms of accomplishing the RAM program goal of securing supply from small-scale renewable facilities and GTSR-qualified facilities. We did identify one issue with the methodology related to the separation of the RAM and Solar PV projects which we address in detail in the next section.

4. LCBF Offer Evaluation Process

- a. Identify guidelines used to determine fairness of evaluation process.*
- b. Utilizing the guidelines in Section IV.A, describe the IE methodology used to evaluate administration of the IOU LCBF process.*
- c. Did the utility identify, for each offer, the terms that deviate from the utility RFO? Did the IOU identify nonconforming offers fairly – fair both to the nonconforming offers and to conforming participants?*
- d. If the IOU conducted any part of the offer evaluation, were the parameters and inputs determined reasonably and fairly? What controls were in place to ensure that the parameters and inputs were reasonable and fair?*
- e. If the IE or a third party conducted any part of the offer evaluation, what information/data did the utility communicate to that party and what controls did the utility exercise over the quality or specifics of the out-sourced analysis?*

- f. *Were transmission cost adders and integration costs properly assessed and applied to offers?*
- g. *Describe any additional measures the utility exercised in evaluating affiliate, buyout, and turnkey offers.*
- h. *Describe any additional criteria or analysis used in creating its short list (e.g. seller concentration, online date, transmission availability, etc.). Were the additional criteria included in the solicitation materials?*
- i. *Results analysis*

When reviewing an evaluation process we look for a process that treats all bidders fairly under the rules of the RFO. If a rule is modified or changed for one bidder then we want to see that modification extended to all bidders. If affiliates are involved we want to see them treated the same as other bidders. We also look for adherence to RFO rules and procedures for evaluation so that all bidders know the process was transparent.

In order to ensure that the RFO delivered the best results for ratepayers, we monitored every step of the process and evaluated the offers independently from PG&E evaluators. At several points we consulted with PG&E's team to ensure that all parties were on the same page regarding bid qualification, bid scoring and selection of a winning portfolio. What follows is a description of the major steps in this process and the results.

Bid Receipt and Qualification

Bids were due on August 21, 2015. Bidders submitted their offers electronically via the Power Advocate platform. As the IE, we had access to all documents submitted and were able to review all offers. As noted, we received submissions from a total of 19 different bidders. Some bidders offered multiple projects; we received a total of 48 projects bid. Several of these projects offered multiple options, for example a different PPA term length or different pricing structure. In total we received 90 different offers. Bids could offer as either energy-only, full capacity deliverability (FCD), that is, energy plus capacity, or partial capacity deliverability (PCDS). Bidders could offer into one of three categories:

- “Baseload” for projects with an annual capacity factor of 80% or greater (e.g. biomass).
- “As-Available Non-Peaking” for projects with an annual capacity factor of 80% or less and less than 95% of expected output in the peak and shoulder periods (e.g. wind).
- “As-Available Peaking” for projects with an annual capacity factor of 80% or less and 95% or more of expected output in the peak and shoulder periods (e.g. solar).

There were several requirements for qualification as a RAM project.

- Bids had to be between 3 and 20 MW in size.
- Bids could be from existing or new facilities.
- Bids had to be from eligible renewable resources. Existing bids had to be certified as eligible renewable resources and new facilities were encouraged to apply for pre-certification.
- Commercial operation had to be achieved by roughly February 2018. Existing facilities under contract needed any current contracts to expire by that point.⁹
- Projects needed to be interconnected to the transmission or distribution system of PG&E, SCE or San Diego Gas & Electric (SDG&E).
- Site control had to be demonstrated for the entire term of the PPA.
- Projects had to have completed a System Impact Study, a Phase I interconnection study, or have documentation showing that the project passed the WDT or CAISO fast track screens at the time of submittal.
- The developer had to have completed or begun construction of at least one other project of similar technology and capacity and the project had to employ technology currently in use at a minimum of two operating facilities of similar capacity.
- The project could not receive funds from the California Solar Initiative or Net Energy Metering Programs.
- RAM projects also qualified as Solar PV Projects if they met the above requirements and were solar-powered.

In addition, bidders could declare if they believed they met the qualification standards for GTSR projects and the GTSR sub-categories of Environmental Justice and Community Projects. GTSR projects had to be new solar-powered projects located in PG&E's service territory and could range in size from 0.5 MW to 20 MW. EJ and Community Projects had to be located in specific areas within PG&E's territory. In addition, EJ projects could be no larger than 1 MW and Community Projects did not need to provide interconnection documentation.

We reviewed each and every offer. Bidders had to submit several documents. These included; a) an offer form which spelled out key details of the project, including price and term, as well as bidder experience and supplier diversity, b) a PPA cover sheet and Appendix which provided pricing, project, and term details and would be attached to the approved PPA to create a final contract should the bidder be selected, c) a questionnaire and attestation providing information regarding site control, d) interconnection studies and a project single-line diagram, and e) for small projects (5 MW or less) an acknowledgement from the site owner that they were

⁹ Several bidders questioned if they could provide supply prior to February 2018. PG&E interpreted the RAM PPA as allowing delivery no more than 180 days prior to the Guaranteed COD per section 3.9(c).(v) . Because the Guaranteed COD was in February of 2018 this translated into an earliest start date of August 2017.

aware of other incentive programs for the project and were not taking advantage of those programs.

In this RFO PG&E evaluators undertook a determined effort to review all documentation provided to ensure that any bidders that qualified would be able to follow through on any offers made. This, plus the addition of newer, less sophisticated bidders from the GTSR program, led to more disqualified offers than last year's RAM RFO. Of the 90 initial offered options, several were disqualified or withdrawn for various reasons:

- Four projects, offering a total of nine options, were withdrawn or disqualified for failing to have a completed system impact study or equivalent at the time of bid submission. One other project had a FCD option disqualified because they did not have a completed deliverability study. That project was evaluated as an energy-only option.
- A total of four options from two projects were disqualified because the bidders offered too many options from each project. Bidders were limited in the number of options they could offer from each project. Other options from these projects were considered.
- Two options representing two projects in total were withdrawn to pursue "other investment objectives." Prior to withdrawal PG&E had raised questions regarding the site control for both projects. PG&E was in the process of obtaining more information on the issue when the bids were withdrawn.
- One project, offering two options was withdrawn due to site control issues. The bidder was "in the final stages" of negotiating site control when the bid was submitted but did not have a final agreement in place at the time it made its offer.
- Two options from two projects were withdrawn due to uncertainty over the extension of the Federal Investment Tax Credit. Other options from these projects were evaluated.

PG&E evaluators discussed each of these disqualifications and withdrawals with Boston Pacific to ensure that we agreed with their rationale for disqualifications or understood the reason for bidder withdrawal. We were in general agreement with the decisions made by PG&E. The only area of disagreement was over the projects withdrawn to pursue "other investment objectives." PG&E initially wanted to disqualify these projects for only providing a letter of intent to negotiate a site lease, rather than an actual site lease. Boston Pacific believed that this could be justified as providing site control and requested more documentation on the agreement, which PG&E dutifully sought. As noted above, before more discovery could be conducted the projects were withdrawn.

After these disqualifications and withdrawals, the evaluators were left with a total of 70 options from 41 projects. What follows is a discussion of the independent evaluation process that Boston Pacific undertook. We used the RFO as a guide to the process along with our own experience and judgment. PG&E undertook a similar process, again, guided by the RFO rules. The main difference in the PG&E process was that their evaluation models were a bit more exacting in terms of the timing of costs. At various points along the way we checked in with PG&E evaluators to ensure we were in agreement regarding bid qualification, the ranking of bids and the selection of initial and final portfolios. As noted later, we were in general agreement with PG&E evaluators on all these items.

Bid Scoring - Process

Once bids were reviewed and qualified they had to be scored. Because all bids signed the same contract they were ranked on a price-only basis. The bid price was comprised of three components:

- **Energy cost** – This is the cost of the direct payments that will be made under the PPA for energy delivered. To calculate this cost we started with the MWh generated based on the operating profile given by the bidder and multiplied that times the annual PPA price provided by the bidder. The PPA price could be flat or increase at a set percentage each year. This product was then multiplied by the Time-of-Day (TOD) delivery factors provided in the PPA and the RFO. TOD factors varied depending on the delivery month and time (peak, shoulder or night) as well as whether the bid was energy-only or fully deliverable.

This calculation was done for every year of the contract and the results were levelized on a per MWh basis over the term of the contract using PG&E's weighted-average cost of capital (WACC) of 7% per the RFO rules.

- **Resource Adequacy Credit** – Bids that offered and demonstrated capacity deliverability were given a credit for their contribution towards resource adequacy costs (RA Credit). RA Credit was given either once online or once network upgrades were completed (if the project's interconnection documentation forecast a later date for deliverability upgrade completion). To calculate this credit we started with the unit size in megawatts and multiplied this quantity times a multiplier representing the Effective Load Carrying Capacity (ELCC) to create a the Net Qualifying Capacity (NQC). The ELCC multiplier is a factor from PG&E's planning process that accounts for the reality that intermittent resources cannot be counted on to produce at their full output at any given time. The ELCC Multipliers used in this analysis are shown in the table below. These multipliers decreased significantly from the RAM V RFO, this had the effect of making FCDS offers less valuable than last year, all else equal.

TABLE FOUR
ELCC MULTIPLIERS

	RAM VI	RAM V
Wind		
Solar PV Fixed		
Solar PV Track		
Solar Thermal		
Solar Storage		

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

We then determined the RA credit by multiplying the monthly NQC times the monthly forecast of Avoided Capacity Cost (ACC) from PG&E’s latest Avoided Capacity Cost Curve. This curve projects the value of capacity in dollars per kilowatt-month from now through 2057 and was not provided to bidders. Consistent with the RFO direction, PG&E provides separate forecasts for the SP15 and NP15 locations, with NP15 prices being higher.

After calculating the RA Credit for each month the final step was to convert that value into a levelized dollar per MWh number, just as we did for the energy cost. To do this we first found the Net Present Value of the Revenue Adjusted for NQC by discounting it back to the starting year of the contract at 7% (again, PG&E’s weighted-average cost of capital). We then did the same for the MWh produced by the unit to get a levelized dollar per MWh credit.

- **Transmission Upgrade Cost** – The final cost component was the cost of reliability and deliverability upgrades for the project. The total upgrade costs were taken from the most recent system impact studies provided by the bidders. Reliability upgrade costs were assessed for nearly all bids.¹⁰ Deliverability

¹⁰ The exception being Community Projects. These projects did not have to provide interconnection materials and therefore interconnection costs were not considered in their selection.

upgrade costs were assessed only for bids offering capacity deliverability. Upgrade costs were grossed up for taxes and spread out in equal amounts over five years in order to reflect how these costs will be recovered from ratepayers. Costs were then converted into a levelized, dollar per MWh payment over the life of the PPA, just as with energy costs and RA Credits.

Boston Pacific built models to calculate the levelized cost of each of these components, then added them together to get the total cost for each bid. As noted above, PG&E evaluators did the same. We periodically checked with PG&E in order to ensure that we agreed on how the bids should be evaluated and that we were generally in agreement on the costs. While the occasional discrepancy was found, all differences were able to be resolved. At the end of the process our independent evaluation method produced results that were very similar to what PG&E came up with and we reached general agreement on the rankings and bid costs.

In the next section we discuss the ranking of bids and selection of offers. A list of all bids- including withdrawn and disqualified bids - showing PG&E's total cost calculation and Boston Pacific calculations of each cost component, is included as Attachment I.

Bid Scoring – RAM and Solar PV Offers

We turn first to the scoring of the RAM and Solar PV offers. We look at this category first because PG&E had pledged to maintain ratepayer indifference to the selection of GTSR projects. In other words, PG&E would ensure that regular ratepayers would not care what projects were selected for the GTSR program. To carry this out, PG&E decided to select RAM and Solar PV projects first and then select GTSR projects.

Past RAM RFOs offers were grouped by category (Baseload, Peaking, Non-Peaking) and bids were selected to fill each target. For this RFO since (a) the RAM category targets for Baseload and Non-Peaking were very small and (b) we received very few offers in those categories we show all RAM and Solar PV-eligible bids in one chart.

The following table shows a ranking of the top performing, qualified RAM and Solar-PV offers received, showing Boston Pacific's calculation of each cost component as well as PG&E's calculation of the total cost of the bids. Again, any solar-powered project that qualified for RAM was also qualified for the Solar PV program. Note that projects could make multiple offers, so some projects are shown more than once.

TABLE FIVE
TOP PERFORMING RAM AND SOLAR-PV PROJECTS

[illegible]

For the selection of initial winning offers PG&E decided to treat the RAM and Solar PV programs as separate requirements and first select projects for the RAM program and then select projects for the Solar PV program. The logic behind this was to maintain a similar ratepayer indifference to project selections for the Solar PV projects by prioritizing RAM projects.

For this RFO PG&E's RAM project target was 32 MW (10 MW Baseload, 12 MW Non-Peaking and 10 MW Peaking). Per RFO protocol, PG&E's actual selections could deviate by up to 20 MW in each category. For the RAM program, PG&E selected the top-performing bid ([REDACTED]) and [REDACTED], giving a total of [REDACTED] MW overall ([REDACTED]). [REDACTED] PG&E did not select [REDACTED] because that would have pushed their total Peaking acquisition to [REDACTED] MW, or [REDACTED] MW above their maximum allowable for RAM Peaking projects.

PG&E then selected the top performing remaining offers for the Solar PV program. Those are shaded in blue above. The target for the Solar PV program was 105 MW. PG&E therefore selected 5 projects providing a total of 98 MW. All other offers were designated as “backup” bids.

While this selection was acceptable under the protocols, it is worth pointing out that there was another method for selecting offers that would have resulted in slightly lower costs and better resource diversity overall. If PG&E had not made a distinction between RAM and Solar PV offers, giving themselves target of 10 MW Baseload 12 MW Non-Peaking and 115 MW Peaking they could have made an a slightly different selection as shown in Table Six below.

TABLE SIX
TOP PERFORMING RAM/SOLAR – PV PROJECTS- ALTERNATE SELECTION

Project	Developer	Technology Type	MW	Term	EDC	BPC Costs (\$/MWh)				PG&E Cost
						TOD-Weighted Energy	RA Credit	Network Upgrade	Total	

In this selection, PG&E could select the top five solar bids for the Solar PV program and taken the top Baseload offer and the top Non-Peaking offer for the RAM program. This in effect drops the [REDACTED] (with a cost of \$ [REDACTED]/MWh) and adds the [REDACTED] (with a cost of \$ [REDACTED]/MWh). This selection is less expensive and more resource diverse and makes more sense given the fact that, unlike the GTSR program, the same ratepayers are paying for the RAM and Solar PV projects, so the RAM ratepayers are not “harmed” by this selection.

We should note that this ultimately did not make a difference in the actual bid selection as the [REDACTED] decided to withdraw from the RFO due to uncertainty over the extension of the Federal Production Tax Credit. Nevertheless in future procurements we would recommend treating these programs as one combined target in order to better optimize bid selection.

Bid Scoring – GTSR Projects

Having selected the RAM and Solar PV offers, PG&E next turned to the selection of GTSR projects. The table below shows the ranking of all qualified GTSR-eligible projects after the selection of RAM and Solar PV bids. Selected bids are shaded.

TABLE SEVEN
GTSR BIDS (POST RAM/SOLAR PV SELECTION)

Project	Developer	Enviromental Justice	Community Project	MW	Term	BPC Costs (\$/MWh)				PG&E Cost
						TOD-Weighted Energy	RA Credit	Network Upgrade	Total	

The GTSR target for RFO was 50 MW (including Environmental Justice and Community Projects). PG&E had the ability to procure up to 68 MW. PG&E began by taking the least

expensive offers, a total of five projects () and a total of MW, with MW of that total being a Community Project.

At this point PG&E could have also selected the , but this would have put them well above their 50 MW target and would have not left much additional room for more Environmental Justice or Community Projects.

PG&E therefore looked to select additional Environmental Justice and Community Projects. For this RFO PG&E had a target of 8.3 MW of EJ Projects and no official target for Community Projects.

Included in this total were two EJ Projects totaling 2 MW and five Community Projects totaling 14.3 MW.¹¹

Overall, Boston Pacific agreed with PG&E's initial selections in portfolio, except for the non-selection of the as noted above. In accordance with the RFO timeline, PG&E extended offers to all these bids on October 30, 2015. Because bidders were under no obligation to accept these offers, and because bidders could submit into the RAM processes for SCE and SDG&E, which were happening concurrently, it was vital to have a robust selection of backup offers as well. PG&E designated a large list of offers as waitlisted resources.

Boston Pacific agreed with this process since it kept many offers open at no cost and there was a high probability of at least some projects rejecting the initial offer.

Initial Contract Offers and Waitlist Response

Bidders in the initial portfolio had until November 4th to make an initial response to the RFO offer by returning a signed copy of the offer letter to PG&E. Waitlisted bidders had to make a similar submission at the same time to indicate their continued interest in the RFO and willingness to sign a PPA if selected. Winning bidders also had to provide additional documentation, including a signed PPA, by November 10th.

Waitlist Response –RAM and Solar PV Projects

Several of the top choices for the RAM/Solar PV category declined to continue in the process. Only two of the six selected bids for this category () decided to sign PPAs. While some projects () did not provide a reason for dropping out, some others did. mentioned

¹¹ Note that the Bakersfield Industrial project was located in an EJ area. However it submitted options for two different points of interconnection, one also in the EJ area and one outside. The selected option used the POI outside of the EJ area. PG&E only counts a project as an EJ project if the entire project is in the EJ area.

uncertainty over rising costs. [REDACTED] dropped out to pursue other opportunities. As noted above, [REDACTED] dropped out due to uncertainty over the extension of the Federal Production Tax Credit.

After receiving responses from bidders, the top performing RAM and Solar PV projects were as shown on the table below. Winning suppliers are shaded.

TABLE EIGHT
TOP RAM/SOLAR PV BIDS POST-NOTIFICATION

Project	Developer	Technology Type	MW	Term	EDC	BPC Costs (\$/MWh)				PG&E Cost
						TOD-Weighted Energy	RA Credit	Network Upgrade	Total	

PG&E repeated the process it used in the initial evaluation by first selecting RAM projects and then selecting Solar PV projects. [REDACTED] (previously selected as a Solar PV project) was designated as the RAM project and the five remaining least expensive projects were designated as Solar PV projects. Unlike the initial selection there was no issue caused by treating the programs separately. These selections provided a total of 20 MW of RAM supply and 93.5 MW of Solar PV supply.

Given this response and the protocols PG&E could have made a couple of other choices. The first would have been to take one more solar project ([REDACTED]). This would have allowed PG&E to meet the combined RAM and Solar PV target, but would have meant that no other type of resource would be taken and total MW taken would be nearly 20 MW above the target. Another option would be to take the [REDACTED] as a RAM Offer, which would have allowed PG&E to hit its RAM target of 32 MW exactly and provided some supply diversity.

PG&E chose to decline these options because a) they would require adding more expensive bids into the portfolio, b) PG&E is already forecast to meet its near-term RPS compliance needs and therefore doesn't have a pressing need for more supply and c) they were permitted to do so under the RFO protocols. While we might have suggested securing one more project given the uncertainty over future costs and the fact that expiration of Federal Incentives

may cause prices to rise in the future we also agree that PG&E is correct on the three counts above, most notably, they are forecast to be in a positive RPS position relative to their requirements through 2021, so we have no major objections to this selection of offers.

Waitlist Response –GTSR Projects

Response for the GTSR projects was stronger than for the RAM/Solar PV projects. Of the eleven projects initially selected eight accepted offers to sign PPAs. As noted above, one of these was the [REDACTED] which was re-designated a Solar PV project. After the waitlist response and selection of RAM/Solar PV projects the GTSR project list was as shown in the table below.

TABLE NINE
GTSR BIDS POST-NOTIFICATION AND RAM/SOLAR-PV SELECTION

Project	Developer	Enviromental Justice	Community Project	MW	Term	BPC Costs (\$/MWh)				PG&E Cost
						TOD- Weighted Energy	RA Credit	Network Upgrade	Total	

To fill the gap left by the [REDACTED] departure, the next least expensive offer, the [REDACTED], was selected. In total eight projects were selected providing a total of 52.75 MW, with 2 MW being EJ Projects and 6.25 MW being Community Projects. We had no objection to these selections.

PG&E then then set about finalizing contracts with the winning bidders. On November 20th PG&E notified all remaining waitlisted projects that they would not be accepted. On December 4th [REDACTED] notified PG&E that its [REDACTED] would not be continuing in the process [REDACTED]

[REDACTED] Because all waitlisted offers had been released from their obligations and because PG&E wanted to stick to the time frame for filing the project PPAs with the CPUC, no further offers were accepted, leaving PG&E shorter on their procurement targets than planned. We agreed with PG&E's rationale for not seeking further offers and believe that it will be easier to simply roll the unmet target into the year's procurement process.

Table Nine below shows the final selection of offers

TABLE TEN
FINAL SELECTED PORTFOLIO

			Community (C) or Env Justice (EJ)Project?	MW	Term	Levelized Energy, \$/MWh	RA, \$/MWh	Transmis sion, \$/MWh	BPGTotal, \$/MWh	PGE Total, \$/MWh
Project	Developer	Technology Type								
RAM/Solar PV Projects										
GASNA 6P, LLC ("San Joaquin 1A")	Solar Frontier Americas Development, LLC	Photovoltaic		20	20					
Java Solar Project	SunPower Corporation	Photovoltaic		13.5	20					
Bayshore Solar A LLC	FTP Power LLC, dba Sustainable Power Group (sPower)	Photovoltaic		20	20					
Bayshore Solar B LLC	FTP Power LLC, dba Sustainable Power Group (sPower)	Photovoltaic		20	20					
Bayshore Solar C LLC	FTP Power LLC, dba Sustainable Power Group (sPower)	Photovoltaic		20	20					
GTSR Projects										
Merced 1	Green Light Energy Corp.	Photovoltaic		3	20					
GASNA 36P, LLC ("San Joaquin 1B FIT")	Solar Frontier Americas Development, LLC	Photovoltaic		1.5	20					
54KR	8minutenergy Renewables, LLC	Photovoltaic		20	20					
Tranquillity 8 Amarillo	Recurrent Energy	Photovoltaic		20	20					
Bakersfield 1	Mirasol Development LLC	Photovoltaic	C	5.25	20					
Bakersfield Industrial 1	Mirasol Development LLC	Photovoltaic	C	1	20					
Delano Land 1	Mirasol Development LLC	Photovoltaic	EJ	1	20					
Manteca Land 1	Mirasol Development LLC	Photovoltaic	EJ	1	20					

The portfolio results in a total acquisition of 146.25 MW. The portfolio is split into 93.5 MW of RAM/Solar PV Projects at a MW-weighted average cost (based on PG&E's calculations of total cost) of \$[REDACTED]/MWh and 52.75 MW of GTSR Projects at a MW-weighted average cost (again, based on PG&E's calculations of total cost) of \$[REDACTED]/MWh. While the GTSR selection is roughly on target the RAM/Solar PV selection falls short of its target by 43.5 MW. This is technically a larger shortfall than PG&E is allowed under the RFO protocol, which says that they can take plus or minus 20 MW in each category. PG&E's combined RAM/Solar PV target for the Peaking category is 115 MW meaning they should select at least 95 MW. However, given that 20 MW of the shortfall is due to the late dropout of the [REDACTED] we think the final selection is acceptable. Boston Pacific agrees with the selection of the portfolio, the conduct of the process that brought it about, and the general calculation of the bid costs.

5. Does the RPS shortlist merit Commission approval?

- a. Did the IOU conduct a fair solicitation that was consistent with Commission decisions and its approved LCBF methodology?*
- b. Did the IOU choose projects for the shortlist that provide the best overall value to ratepayers while meeting the IOU's RPS compliance needs? Could the IOU have incorporated a decision-making process that provided for a different portfolio of projects that provide better overall ratepayer value while meeting the IOU's RPS compliance needs?*
- c. Did the shortlist conform to the needs of the IOU's portfolio, RPS requirements, RPS procurement plan and protocol?*

This RFO did not result in a shortlist, per se, but rather several contracts that are being submitted to the Commission for approval. For discussion of the merits of those contracts and this process, please see the following sections.

6. Fairness of Project Specific Negotiations

- a. Identify principles used to evaluate the fairness of the negotiations.*
- b. Using the above principles (section V.A), please evaluate fairness of project-specific negotiations.*
- c. Identify the terms and conditions that underwent significant changes during the course of negotiations?*
- d. Was similar information/options made available to other participants, e.g. if a participant was told to reduce its price down to \$X, was the same information made available to others?*
- e. Any other relevant information or observations, such as other data or information used to inform the negotiations.*

Typically in a negotiation resulting from a formal procurement process we look to see that the final contract matches the offer made in the procurement process and that the negotiations were fair. In this case there was no negotiation allowed regarding the PPA, which was a document pre-approved by the Commission. All bidders agreed to the same PPA. The only thing to distinguish each offer was a PPA “cover sheet” and Appendix which spelled out specific details of the project, including price, term, location, name, size, commercial operation date, and so forth. We did review the PPA cover sheets submitted by selected bidders in order to ensure that the parameters entered by the bidders matched the initial offers as well as

communications between the bidders and PG&E. During the contracting process no material changes were made.

7. Does the Contract Merit CPUC Approval?

- a. Provide narrative for each category and describe the project's ranking relative to: 1) other offers from the solicitation (or recent bilaterals or market information if used in reasonableness comparison; 2) other procurement opportunities (e.g. distributed generation programs); and 3) from an overall market perspective:*
 - 1. Contract Price, including transmission cost adders*
 - 2. Project's net market value*
 - 3. Consistency with stated RFO goals*
 - 4. Portfolio Fit*
 - 5. Project Viability*
 - 1. Project Viability Calculator score*
 - 2. IOU-specific project viability measures*
 - 3. Other (credit and collateral, developer's project development portfolio, transmission, other site-related matters, etc.)*
 - 6. Any other relevant factors*
- b. Do you agree with the IOU that the contract merits CPUC approval? Explain the merits of the contract based on offer evaluation, contract negotiations, final price, and viability.*
- c. Any other relevant information or observations*

We believe that the CPUC should approve the PPAs resulting from the RAM VI RFO. We make this recommendation for four reasons.

First, the procurement process was open, fair, and transparent. This applies to both the design of the procurement and the way in which it was carried out. Regarding the design, the selection of bids was based almost entirely on price, with all bidders signing the same contract. The majority of the bid price was based on energy costs, which were provided by the bidders themselves. Bidders were also provided with TOD factors and PG&E's discount rate so that they understood exactly how their bid cost would be calculated. The only other consideration

was bid category and the RFO provided explicit targets for each category along with specific direction regarding the amount by which PG&E could vary those targets. Qualification guidelines were also clearly spelled out in the RFO.

Regarding the implementation of the procurement, this was fair and transparent as well. All bidders were treated the same and the evaluation was conducted as described in the RFO documents. Boston Pacific was able to independently review and evaluate every offer made in response to the RFO. We were able to compare our evaluation to those of PG&E evaluators and come to a general agreement on key decisions like bidder disqualification, ranking of top bids, selection of an initial recommended portfolio, and selection of a final portfolio. Boston Pacific was also able to participate in phone calls between parties, and review both contract documents and e-mails between parties.

Second, the RFO was competitive. In total, the RFO received offers from 19 bidders. These bidders made a total of 90 individual offers from 48 projects. For every MW needed the RFO attracted about 3.3 times that amount. While this is down quite a bit from the RAM V RFO, which saw 103 offers from 69 projects and 25 bidders, it still represents a reasonable offer. While Offers in the Baseload category were sparse, the Non-Peaking category saw 4.3 MW offered for every MW needed, a reasonable ratio. Moreover, the GTSR program saw 427.3 MW worth of offers, roughly 8.5 times the 50 MW target. Having good levels of competition provides us with a high level of confidence that the winning offers are market-competitive offers.

Third, the prices for the winning bids are reasonable. We can assess the prices in at least two ways. First and foremost we can compare the prices of the selected offers to those selected in the RAM V RFO. Boston Pacific calculates the MW-weighted-average levelized price of the winning RAM and Solar PV bids to be \$[REDACTED]/MWh based on PG&E's calculations of total cost. The average cost for the final selected projects in the RAM V RFO was \$[REDACTED]/MWh - essentially the same.

For the GTSR projects the MW-weighted average winning price is \$[REDACTED]/MWh. This is not surprising as the GTSR projects were selected after the lower-priced RAM and Solar PV projects, limited to PG&E's service territory and included smaller projects in areas that might not be ideal for production. Moreover, Solar Projects to exhibit economics of scale to a degree. For example, the Lawrence Berkley National Lab (LBNL) reports that the median capital cost of Non-Residential solar projects in the U.S sized between 1 and 5 MW as \$2.70/Watt in 2014¹². For the same time period the median price of "utility scale" solar projects (projects larger than 5 MW) was \$2.34/Watt¹³ meaning the smaller projects carried a 15% price premium. Note also

¹² Galen Barbose and Niam Dargouth, *Tracking the Sun VIII: The Installed Price of residential and Non-Residential Solar Photovoltaic Systems in the United States*, August 2015, data file Figure 18.

¹³ Mark Bolinger and Joakim Seel, *Utility Scale Solar 2014: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States*, September 2015, data file Figure 6.

that the \$[REDACTED]/MWh price is roughly comparable with the cost of the RAM IV RFO signed PPAs, which averaged \$[REDACTED]/MWh.

Another comparison, albeit a bit less precise, is to compare these winning prices to publically reported data regarding solar PV PPA costs. In the LBNL Report on utility scale solar costs the authors provide data regarding average publically reported solar PPA prices over time by contract vintage.¹⁴ The data is provided in real 2014 dollars. If we take the most recent (2015 vintage) contracts, gross up the annual reported costs of these contracts for the 2018 to 2037 period using a 2.5% interest rate, and calculate a levelized dollar per MWh value using a 7% interest rate (as we do in this RFO) we get an average cost of about \$[REDACTED]/MWh, similar to the winning contracts presented here.

Finally, all the RFO rules and regulations were appropriately followed. PG&E evaluators appropriately followed the guidelines and rules laid out in the RFO when determining the total amount of supply to take as well as the amount to take in each category. PG&E's selected offers met the RFO targets in terms of supply and PG&E's selected offers in each product category are consistent with its discretion as laid out in the RFO. The qualification and evaluation of offers was done according to RFO rules. The signing of final agreements was done fairly and, consistent with RFO rules, there was no negotiation of PPA terms.

We have three observations from this procurement. First as detailed above, PG&E treated the selection of RAM projects as separate and distinct from Solar PV projects despite the fact that the projects are paid for by the same group of ratepayers. Again, this had no effect on the final selection of bids but it did lead PG&E to make an initial selection of bids that was slightly more expensive than, and not as diverse as, it could have been. In the future we would recommend that PG&E optimize the selection of RAM and Solar PV together rather than treating them as separate targets.

Second, as noted above, three of the winning projects are projects on a contiguous piece of land. Other offers in this RFO exhibited similar characteristics – notably the [REDACTED]. Again, there is no restriction against the daisy chaining of projects in this RFO. If the Commission feels that this offer structure is inconsistent with the goals of the RAM program they should enact similar restrictions here. We note that this will almost certainly reduce the number of MW offered into the RAM procurement.

Finally, solar- powered systems, and photovoltaic solar in particular, continue to dominate the offerings in this RFO process. All bids signed were solar-powered. This is to be expected due to California's solar resources and market price trends as well as the fact that the GTSR and Solar PV programs were only open to solar resources. However, the side effect is that other types of renewable resources are less competitive in these open procurements. If the Commission feels like the California utilities require more diversity in terms of renewable

¹⁴ *Ibid* Figure 17.

resources they may want to consider a separate procurement or procurements targeted directly for those types of resources.

ATTACHMENT I
BIDS RECEIVED

Attachment I - All Bids Offered

Project Withdrawn

Project Disqualified

Project	Developer	Technology	MW	Term	EDC	Project Eligibility				BPC Costs (\$/MWh)				PGE Total Cost (\$/MWh)
						RAM/PV	GTSR	EJ	Community	TOD-Weighted Energy	RA Credit	Network Upgrade	Total	

Attachment I - All Bids Offered

Project Withdrawn
Project Disqualified

[illegible]

Public Appendix G

Summary of Solicitation Participation

APPENDIX G**Names of participating companies and the number of offers per company**

Indicates winning counterparty

CONFORMING OFFERS		
Item:	Developers	Number of Offers Submitted
1	8minutenergy Renewables, LLC	1
2	Colemko, LLC	1
3	Del Sol NRG, Inc.	3
4	E.ON	4
5	EDF Renewable Development	5
6	First Solar, Inc.	8
7	FTP Power LLC, dba Sustainable Power Group (sPower)	5
8	Green Light Energy Corp.	1
9	Mega Point Energy, LLC	1
10	Mirasol Development LLC	18
11	New Dimension Energy Company, LLC	1
12	Recurrent Energy	18
13	Republic Services	2
14	Solar Frontier Americas Development, LLC	4
15	SolarGen USA LLC (together with GCL Solar Energy, Inc.)	2
16	SunEdison Utility Solutions, LLC	1
17	SunPower Corporation	3
18	W Power, LLC	1
		79
NON CONFORMING (did not pass viability screen)		
	Apex Natural Renewable Generation, LLC	1
	E.ON	2
	Green Light Energy Corp.	5
	Mirasol Development LLC	3
Total Non Conforming		11
Total Offers		90

CONFORMING OFFERS				
Baseload Product Category				
Item No:	Counterparty	ERR Type	Contract Capacity (MW)	Annual Generation (GWh)
1	Republic Services	Landfill Gas	6.0	42.1
2	Republic Services	Landfill Gas	6.0	42.1
2	Total Baseload		6.0	42.1

As Available Off-Peak				
Item No:	Counterparty	ERR Type	Contract Capacity (MW)	Annual Generation (GWh)
1	EDF Renewable Development	Wind	20.0	72.6
2	EDF Renewable Development	Wind	20.0	72.6
3	EDF Renewable Development	Wind	19.8	65.0
4	EDF Renewable Development	Wind	19.8	65.0
5	New Dimension Energy Company, LLC	Wind	12.0	37.4
5	Total As Available Off-Peak		51.8	175.0

As Available On-Peak				
Item No:	Counterparty	ERR Type	Contract Capacity (MW)	Annual Generation (GWh)
1	8minutenergy Renewables, LLC	Photovoltaic	20.0	52.1
2	Colemko, LLC	Photovoltaic	2.4	5.4
3	Del Sol NRG, Inc.	Photovoltaic	0.5	0.7
4	Del Sol NRG, Inc.	Photovoltaic	1.5	1.8
5	Del Sol NRG, Inc.	Photovoltaic	1.5	12.2
6	E.ON	Photovoltaic	13.0	33.1
7	E.ON	Photovoltaic	20.0	52.1
8	E.ON	Photovoltaic	20.0	52.6
9	E.ON	Photovoltaic	13.0	33.4
10	EDF Renewable Development	Photovoltaic	18.0	58.7
11	First Solar, Inc.	Photovoltaic	20.0	48.8
12	First Solar, Inc.	Photovoltaic	20.0	48.8
13	First Solar, Inc.	Photovoltaic	20.0	54.4
14	First Solar, Inc.	Photovoltaic	20.0	55.7
15	First Solar, Inc.	Photovoltaic	20.0	48.8
16	First Solar, Inc.	Photovoltaic	20.0	48.8
17	First Solar, Inc.	Photovoltaic	20.0	54.4
18	First Solar, Inc.	Photovoltaic	20.0	55.7
19	FTP Power LLC, dba Sustainable Power Group (sPower)	Photovoltaic	20.0	53.7
20	FTP Power LLC, dba Sustainable Power Group (sPower)	Photovoltaic	20.0	53.7
21	FTP Power LLC, dba Sustainable Power Group (sPower)	Photovoltaic	20.0	57.0
22	FTP Power LLC, dba Sustainable Power Group (sPower)	Photovoltaic	20.0	57.0
23	FTP Power LLC, dba Sustainable Power Group (sPower)	Photovoltaic	20.0	57.0
24	Green Light Energy Corp.	Photovoltaic	3.0	6.2
25	Mega Point Energy, LLC	Photovoltaic	6.0	11.3
26	Mirasol Development LLC	Photovoltaic	5.3	12.9
27	Mirasol Development LLC	Photovoltaic	1.0	2.3
28	Mirasol Development LLC	Photovoltaic	1.0	2.6

APPENDIX G

29	Mirasol Development LLC	Photovoltaic	1.0	2.0
30	Mirasol Development LLC	Photovoltaic	5.3	12.9
31	Mirasol Development LLC	Photovoltaic	5.3	12.9
32	Mirasol Development LLC	Photovoltaic	5.3	12.9
33	Mirasol Development LLC	Photovoltaic	1.0	2.3
34	Mirasol Development LLC	Photovoltaic	1.0	2.3
35	Mirasol Development LLC	Photovoltaic	1.0	2.3
36	Mirasol Development LLC	Photovoltaic	1.0	2.6
37	Mirasol Development LLC	Photovoltaic	1.0	2.6
38	Mirasol Development LLC	Photovoltaic	1.0	2.0
39	Mirasol Development LLC	Photovoltaic	1.0	2.0
40	Mirasol Development LLC	Photovoltaic	5.3	12.9
41	Mirasol Development LLC	Photovoltaic	5.3	12.9
42	Mirasol Development LLC	Photovoltaic	1.0	2.3
43	Mirasol Development LLC	Photovoltaic	1.0	2.3
44	Recurrent Energy	Photovoltaic	20.0	55.1
45	Recurrent Energy	Photovoltaic	20.0	55.1
46	Recurrent Energy	Photovoltaic	20.0	55.1
47	Recurrent Energy	Photovoltaic	20.0	55.1
48	Recurrent Energy	Photovoltaic	20.0	55.1
49	Recurrent Energy	Photovoltaic	20.0	55.0
50	Recurrent Energy	Photovoltaic	20.0	55.0
51	Recurrent Energy	Photovoltaic	20.0	55.2
52	Recurrent Energy	Photovoltaic	20.0	55.2
53	Recurrent Energy	Photovoltaic	20.0	55.2
54	Recurrent Energy	Photovoltaic	20.0	55.1
55	Recurrent Energy	Photovoltaic	20.0	55.1
56	Recurrent Energy	Photovoltaic	20.0	55.1
57	Recurrent Energy	Photovoltaic	20.0	55.1
58	Recurrent Energy	Photovoltaic	20.0	55.1
59	Recurrent Energy	Photovoltaic	20.0	55.0
60	Recurrent Energy	Photovoltaic	20.0	55.0
61	Recurrent Energy	Photovoltaic	20.0	55.2
62	Solar Frontier Americas Development, LLC	Photovoltaic	20.0	49.8
63	Solar Frontier Americas Development, LLC	Photovoltaic	1.5	3.7
64	Solar Frontier Americas Development, LLC	Photovoltaic	20.0	49.8
65	Solar Frontier Americas Development, LLC	Photovoltaic	20.0	49.8

66	SolarGen USA LLC (together with GCL Solar Energy, Inc.)	Photovoltaic	9.0	20.2
67	SolarGen USA LLC (together with GCL Solar Energy, Inc.)	Photovoltaic	9.3	20.8
68	SunEdison Utility Solutions, LLC	Photovoltaic	1.0	2.6
69	SunPower Corporation	Photovoltaic	13.5	35.9
70	SunPower Corporation	Photovoltaic	13.5	35.9
71	SunPower Corporation	Photovoltaic	13.5	35.9
72	W Power, LLC	Photovoltaic	20.0	49.2
72	Total As-Available On-Peak		528.7	1,414.0

79	Total Conforming Offers Received		586.5	1,631.0
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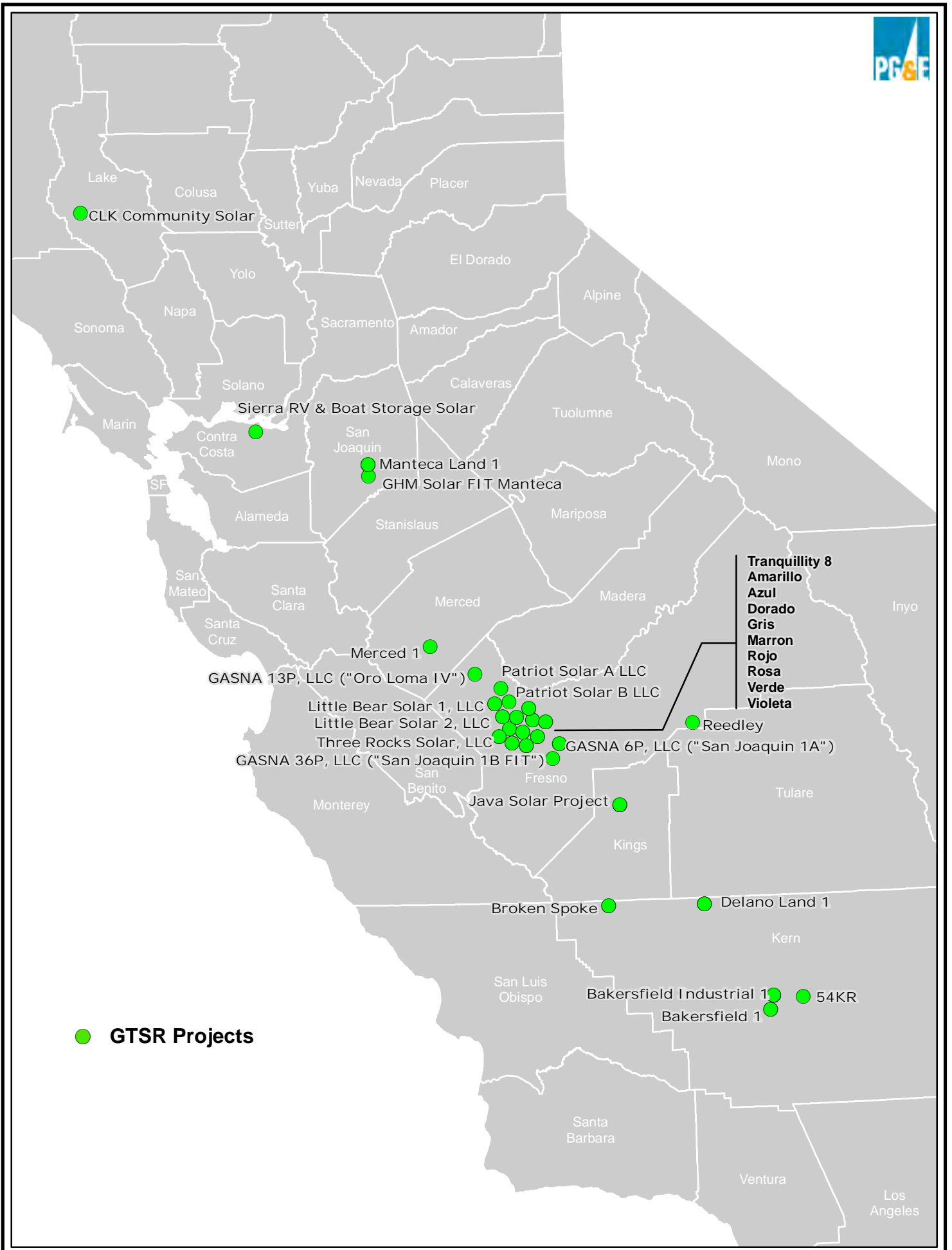
NON CONFORMING OFFERS (Offer(s) that did not meet viability screen)					
	Counterparty	ERR Type	Contract Capacity (MW)	Annual Generation (GWH)	Reason
1	Apex Natural Renewable Generation, LLC	Photovoltaic	0.8	1.7	Interconnection Issues
2	E.ON	Photovoltaic	10.0	27.6	Site Control Issues
3	E.ON	Photovoltaic	10.0	27.3	Site Control Issues
4	Green Light Energy Corp.	Photovoltaic	1.5	3.3	Interconnection Issues
5	Green Light Energy Corp.	Photovoltaic	1.0	1.9	Interconnection Issues
6	Green Light Energy Corp.	Photovoltaic	1.5	3.3	Interconnection Issues
7	Green Light Energy Corp.	Photovoltaic	1.0	1.9	Interconnection Issues
8	Green Light Energy Corp.	Photovoltaic	3.0	6.2	Interconnection Issues
9	Mirasol Development LLC	Photovoltaic	4.5	11.2	Interconnection Issues
10	Mirasol Development LLC	Photovoltaic	4.5	11.2	Interconnection Issues
11	Mirasol Development LLC	Photovoltaic	4.5	11.2	Interconnection Issues
11	Total Non Conforming Offers		16.8	43.5	

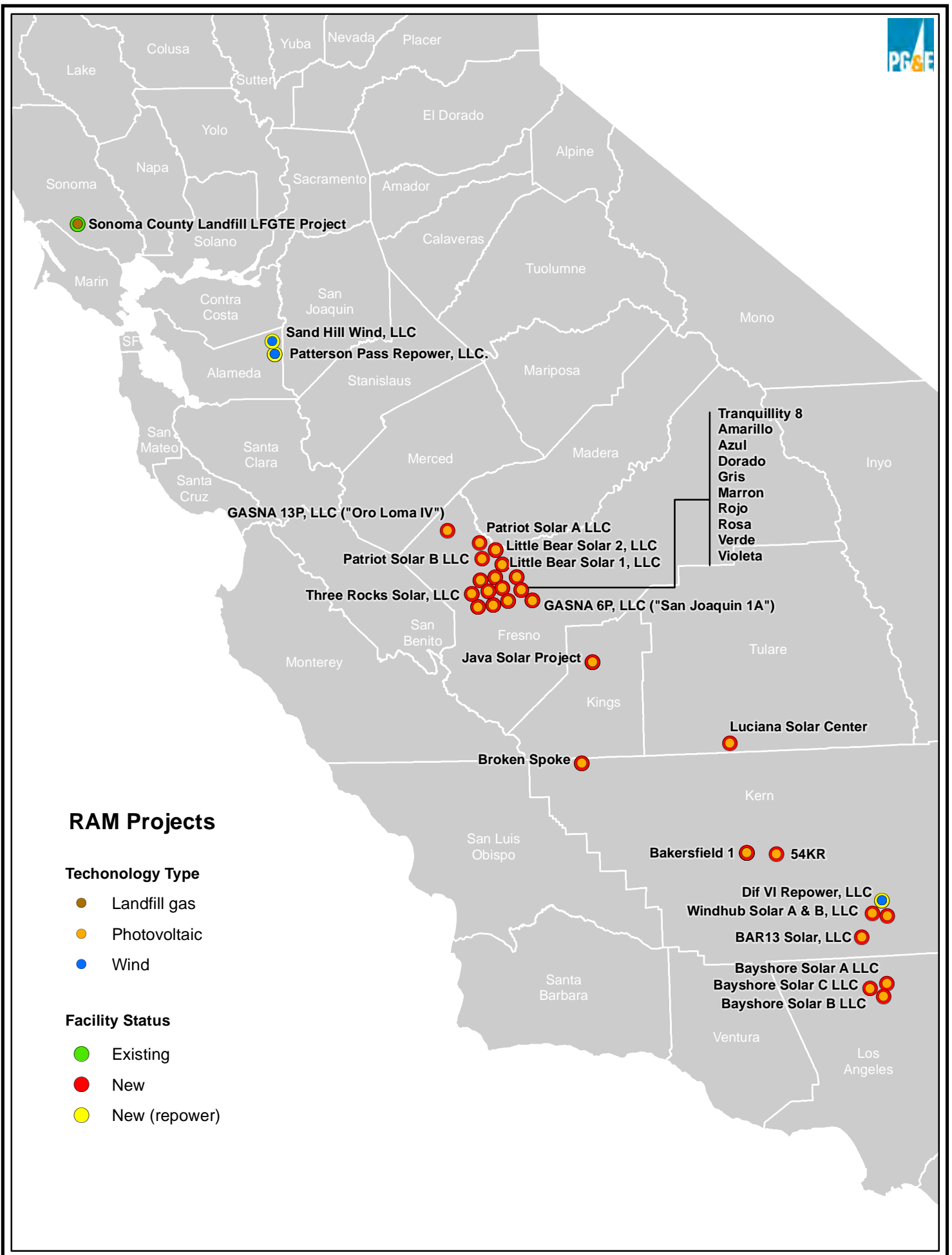
90			603.2	1,674.5
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Note: The MW totals and annual GWh for each product category do not include project variations.

Public Appendix H

Location of Bids





**PG&E Gas and Electric
Advice Filing List
General Order 96-B, Section IV**

AT&T	Division of Ratepayer Advocates	OnGrid Solar
Albion Power Company	Don Pickett & Associates, Inc.	Pacific Gas and Electric Company
Alcantar & Kahl LLP	Douglass & Liddell	Praxair
Anderson & Poole	Downey & Brand	Regulatory & Cogeneration Service, Inc.
Atlas ReFuel	Ellison Schneider & Harris LLP	SCD Energy Solutions
BART	G. A. Krause & Assoc.	SCE
Barkovich & Yap, Inc.	GenOn Energy Inc.	SDG&E and SoCalGas
Bartle Wells Associates	GenOn Energy, Inc.	SPURR
Braun Blaising McLaughlin & Smith, P.C.	Goodin, MacBride, Squeri, Schlotz & Ritchie	San Francisco Water Power and Sewer
Braun Blaising McLaughlin, P.C.	Green Power Institute	Seattle City Light
CENERGY POWER	Hanna & Morton	Sempra Energy (Socal Gas)
CPUC	International Power Technology	Sempra Utilities
California Cotton Ginners & Growers Assn	Intestate Gas Services, Inc.	SoCalGas
California Energy Commission	Kelly Group	Southern California Edison Company
California Public Utilities Commission	Ken Bohn Consulting	Spark Energy
California State Association of Counties	Leviton Manufacturing Co., Inc.	Sun Light & Power
Calpine	Linde	Sunshine Design
Casner, Steve	Los Angeles County Integrated Waste Management Task Force	Tecogen, Inc.
Center for Biological Diversity	Los Angeles Dept of Water & Power	Tiger Natural Gas, Inc.
City of Palo Alto	MRW & Associates	TransCanada
City of San Jose	Manatt Phelps Phillips	Troutman Sanders LLP
Clean Power	Marin Energy Authority	Utility Cost Management
Coast Economic Consulting	McKenna Long & Aldridge LLP	Utility Power Solutions
Commercial Energy	McKenzie & Associates	Utility Specialists
Cool Earth Solar, Inc.	Modesto Irrigation District	Verizon
County of Tehama - Department of Public Works	Morgan Stanley	Water and Energy Consulting
Crossborder Energy	NLine Energy, Inc.	Wellhead Electric Company
Davis Wright Tremaine LLP	NRG Solar	Western Manufactured Housing Communities Association (WMA)
Day Carter Murphy	Nexant, Inc.	YEP Energy
Defense Energy Support Center	ORA	
Dept of General Services	Office of Ratepayer Advocates	