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

Application of Pacific Gas and Electric Company for Expedited Approval of the Power Purchase Agreement with Nevada Irrigation District and for Authority to Recover the Costs of the Agreement In Rates U39E	A1206014 **Application No.**

**APPLICATION OF
PACIFIC GAS AND ELECTRIC COMPANY (U 39-E) FOR
APPROVAL OF ITS POWER PURCHASE AGREEMENT WITH
NEVADA IRRIGATION DISTRICT AND FOR
AUTHORITY TO RECOVER THE COSTS
OF THE AGREEMENT IN RATES**

**PUBLIC VERSION
(Confidential Appendices A, B-1 and C-1)**

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I. INTRODUCTION AND AUTHORITY REQUESTED.

In this Application ("Application"), Pacific Gas and Electric Company ("PG&E") seeks California Public Utilities Commission ("Commission") approval of a Power Purchase Agreement ("PPA") between Nevada Irrigation District ("NID") and PG&E for the capacity of four hydroelectric powerhouses for a twenty-year term. The four powerhouses are part of NID's Yuba-Bear Hydroelectric Project ("YB Project") which supplies 77 megawatts ("MW") of resource adequacy ("RA") capacity and are located in Nevada City and Grass Valley, California,[1] within the area designated by the California Independent System Operator ("CAISO") as the Sierra Local Area.

Three of the powerhouses are California Energy Commission ("CEC")-certified eligible renewable energy resources for purposes of the Renewables Portfolio Standard ("RPS"), while the fourth powerhouse is a large hydro facility with capacity above the 30 MW RPS eligibility

[1] The Chicago Park, Dutch Flat No. 2, and Bowman powerhouses are located in Nevada City; the Rollins powerhouse is located in Grass Valley.

limit.[2] PG&E requests approval of the PPA by application, rather than the advice letter process required for RPS PPAs because (1) approximately half of the resource is RPS-eligible and the other half is large hydro and (2) two RPS non-modifiable terms have been modified, only to the extent necessary, to clarify that the large hydro facility is not an RPS-eligible resource.

This contract merits unconditional Commission approval because of its many benefits. The PPA grants PG&E rights to schedule and dispatch generation from the four powerhouses, subject to hydrological conditions and the terms of a coordinated operating agreement between the parties. PG&E's right to dispatch the YB Project enables PG&E to maximize the productivity of its own hydroelectric system, the Drum Spaulding ("DS") Project, which shares common water storage, conveyance, and control facilities with the YB Project. The PPA procures RA capacity in the CAISO-defined capacity-deficient South of Palermo sub-area within the Sierra Local Area. In addition, the renewable generation procured from these in-state RPS-eligible facilities under the twenty-year contract is particularly valuable because it falls into the RPS generation category for which the target is the highest. Each of these advantages is explained in more detail below.

PG&E currently receives power from the YB Project under two long-term agreements with NID. The first is the Yuba-Bear Consolidated Contract between PG&E and NID ("Consolidated Contract"), which governs procurement from the Chicago Park, Dutch Flat No. 2 and Rollins powerhouses and expires in July 2013.[3] The second is a thirty-year Qualifying Facility ("QF") Standard Offer 4 ("SO 4") contract for the Bowman powerhouse that expires in December 2016. The output of all four powerhouses within the YB Project will be covered by the new PPA.

[2] Existing hydroelectric generation is an "eligible renewable energy resource" only if it is small hydroelectric generation of 30 megawatts or less, meets certain in-state locational criteria, and sold its electricity to a retail seller as of December 31, 2005. (California Public Utilities Code Sec. 399.12(e)(1).) All statutory references in the Application refer to the California Public Utilities Code unless stated otherwise.

[3] The Yuba-Bear Consolidated Contract is a two-part contract consisting of the Yuba-Bear Project Power Purchase Contract, which is Part I, and the Yuba-Bear Water Operation Contract, which is Part II. The Water Operation Contract governs the coordinated operations of and water conveyance between the YB Project and PG&E's DS Project.

Table 1
YB Project Overview

Powerhouse	Capacity (MW)[4]	Annual Energy Deliveries (GWh)[5]	RPS-Eligible	Ancillary Services Capability
Chicago Park Powerhouse	38	148.9	N	Spin, Non-Spin
Dutch Flat Powerhouse No. 2	26	44.4	Y	Spin, Non-Spin
Rollins Powerhouse	11.75	74.5	Y	None
Bowman Powerhouse	2.75	14.4	Y	None
Total	**76.6**	**282.2**		

The YB Project is hydrologically linked to PG&E's 190 MW DS Project, which is comprised, in part, of twelve powerhouses located both upstream and downstream of the NID powerhouses.[6] As shown in Figure A below, the powerhouses of the YB Project (other than the small Bowman powerhouse) and the powerhouses of the DS Project are located on the same watersheds and share the same water conveyance system. PG&E and NID's personnel have well-established working relationships and a mutual understanding of both of their respective systems and their integration.

PG&E anticipates that the current Yuba-Bear Water Operations Contract, which coordinates the operations of and water conveyance through the YB Project and the DS Project

[4] As used in this Application, the term "capacity" refers to resource adequacy ("RA") capacity, which is the amount of a generator's capacity that PG&E submits to the Commission in its RA filing as a load serving entity ("LSE"). PG&E also submits RA capacity information in its supply plan to the CAISO, as the scheduling coordinator for these four powerhouses. Table 1 lists the 2012 Net Qualifying Capacity ("NQC") of each powerhouse (for the peak month of July), which represents the CAISO's determination of capacity deliverability based on its annual deliverability assessment. RA Capacity differs from Contract Capacity, which is determined by a capacity test. The current Contract Capacity for the YB Project is approximately 83 MW. All references to NID powerhouse capacity in the Application refer to RA capacity, not Contract Capacity.

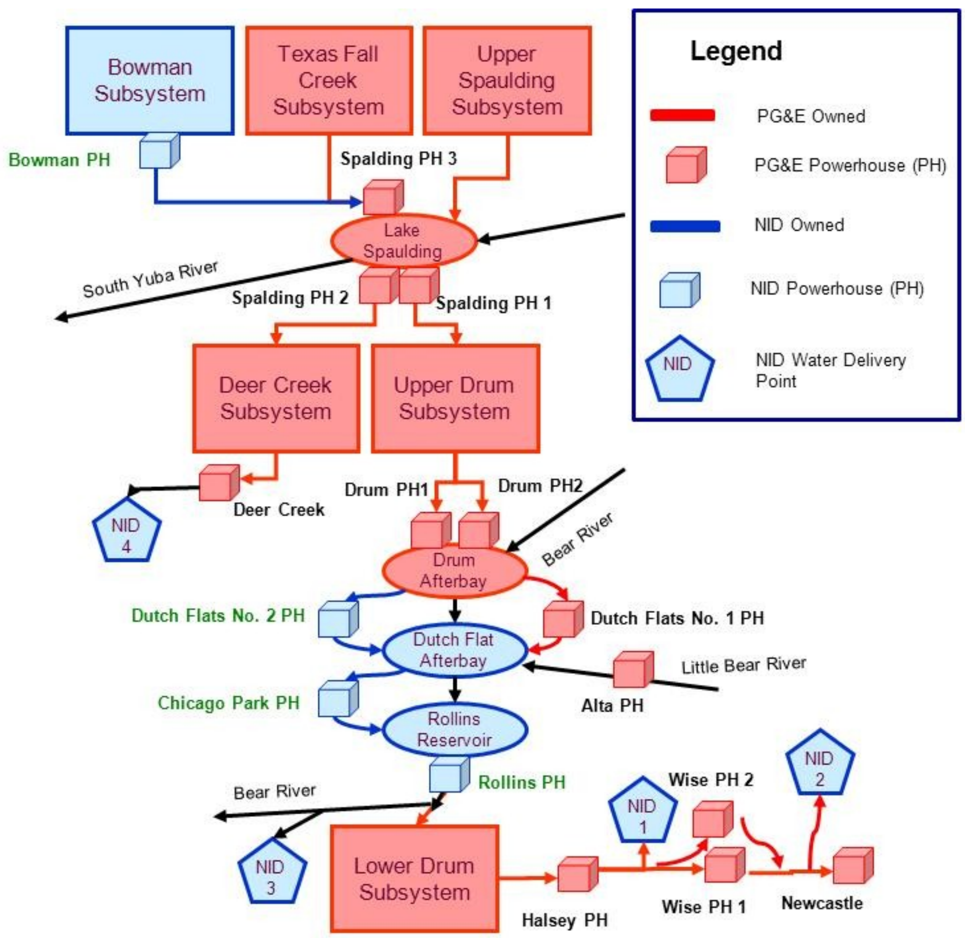
[5] Based on expected annual generation for an average hydro year after NID's new long-term FERC license becomes effective

[6] The twelve DS Project powerhouses are: Spaulding No's. 1, 2, and 3; Deer Creek; Alta; Drum No's. 1 and 2; Dutch Flat No. 1; Halsey; Wise; Wise No. 2; and Newcastle.

will be replaced upon its expiration by a Coordinated Operations and Water Conveyance Agreement ("COA"). PG&E and NID are currently negotiating the terms and conditions of the COA, with the goal of coordinating the planning and operation of the two projects as needed, to manage the supply of water for generation by the two hydroelectric systems and to meet NID's consumptive demands.[7]

Figure A

Schematic of YB Project and DS Project



The new PPA will provide the following substantial benefits:

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[7] NID is also obligated to serve consumptive water demand in its service territory. The majority of NID's water delivery points are located downstream of the YB Project. *See*, Figure A.

1. Preservation of Integrated Operations, Optimization and Dispatch with PG&E's Hydro System. PG&E's retention of the right to capacity and generation from the YB Project, instead of allowing a third-party to schedule energy deliveries from the powerhouses, will facilitate PG&E's continued coordination of the planning, optimization, scheduling, and water usage by which the operational and cost benefits of the two hydro systems are maximized, as they are today.

2. Provision of Local Reliability. The YB Project is located in the South of Palermo sub-area of the Sierra local area, which has been identified by the CAISO as capacity-deficient to meet North American Electric Corporation ("NERC") reliability standards in that area,[8] and thus is uniquely qualified to support local reliability needs.

3. Guaranteed Dispatch Capability. The PPA provides PG&E with scheduling rights, subject to the terms of the COA. The Chicago Park and Dutch Flat No. 2 powerhouses have relatively high ramp rates and can respond to dispatch instructions as needed, subject to their respective hydrological limitations.

4. Availability of Ancillary Services. The Chicago Park and Dutch Flat No. 2 powerhouses can provide spinning and non-spinning reserves.

5. Demonstrated Viability. The YB Project has been operational for almost fifty years and the NID powerhouses utilize well-established hydroelectric generation technology.

6. Premium RPS Value. Project generation from the RPS-eligible powerhouses falls within the RPS statute's first portfolio content category, i.e., in-state generation from eligible renewable resources interconnected within the CAISO. The ability to apply YB Project deliveries from this twenty-year contract toward PG&E's present and future RPS obligations enhances the value of the PPA for PG&E's customers.

PG&E hereby submits the PPA for Commission review and approval and requests the Commission to issue a decision that: (1) finds that PG&E's execution of the PPA is prudent and

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[8] Further details provided in *2013 Local Capacity Technical Analysis – Final Report and Study Analysis of the CAISO*, dated April 30, 2012.

authorizes PG&E to recover all costs associated with the PPA through PG&E's Energy Resource Recovery Account ("ERRA") and (2) finds that the power generated by the three RPS-eligible small hydroelectric powerhouses is RPS-eligible for the purpose of compliance with PG&E's RPS obligation.

II. DESCRIPTION OF THE NEVADA IRRIGATION DISTRICT TRANS-ACTION.

A. General Project Description.

Each of the four powerhouses within the YB Project is owned and operated by NID, which is licensed by the Federal Energy Regulatory Commission ("FERC") to operate the YB Project under the terms of a fifty-year license scheduled to expire on April 30, 2013. NID is currently in the later stages of obtaining a successor license from FERC, which is expected to have a term of at least thirty years. If FERC approval is not obtained by the expiration date of the existing license, it is expected that NID will receive a provisional extension of its existing FERC license for the YB Project with similar terms and conditions.

The operation of the YB Project is highly coordinated with the operation of PG&E's DS Project[9] due to the physical integration of the projects. The planning and operation of the two projects, especially the conveyance and delivery of water, are coordinated under the existing Water Operation Contract. PG&E expects that this agreement will continue in effect until a new COA becomes effective. The COA is currently under negotiation. The existing and new operational agreements are separate from, but complementary to, the existing and the subject PPA for PG&E's purchase of the output of the NID powerhouses.

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[9] PG&E's DS Project is located along the South Yuba River and the Bear River in northern California. The DS Project consists of 12 powerhouses with a combined installed generating capacity of 192 MW, 86 MW of which is RPS-eligible.

PROCUREMENT SUMMARY

Project Name	Nevada Irrigation District ("NID")
Technology	Hydroelectric
Capacity (MW)	76.6 MW
Capacity Factor	Approximately 42% (average hydro year)
Expected Generation (GWh/Year)	Approximately 282 GWh/year (average hydro year)
Date Contract Delivery Term Begins	July 1, 2013; and January 1, 2017 (for Bowman Powerhouse only)
Delivery Term (Years)	20 years
Location (City and State)	Nevada City, CA and Grass Valley, CA
Control Area (e.g., CAISO, BPA)	CAISO
Price relative to MPR (i.e. above/below)	Below the applicable MPR assuming average hydro year conditions

B. General Deal Structure.

As noted above, PG&E currently procures the output from the YB Project under two power purchase agreements that will expire in 2013 and 2016, respectively, the YB Project Power Purchase Contract and the Bowman Powerhouse SO 4 contract.

The PPA consolidates the purchase of power under these two contracts into a single new agreement between PG&E and NID. Deliveries from the Chicago Park, Dutch Flat, and Rollins powerhouses under the PPA will begin in 2013 upon the expiration of the YB Project Power Purchase Contract, subject to the satisfaction of all the conditions precedent as required in the PPA. Deliveries from Bowman Powerhouse under the PPA are expected to begin in 2016 upon the expiration of the SO 4 contract.

Under the new, PPA PG&E will have scheduling and dispatch rights over YB Project capacity and can optimize water usage across months and within hours of the day subject to the terms of the COA, which will address the management of hydrological limitations, FERC license requirements, and the parties' respective water rights as licensed with the State Water Resources Board ("SWRB").

Assuming average hydrological conditions over the term of the agreement, the cost on a $/MWh basis would equate to a price below the current 2011 MPR.

C. Power Purchase Agreement Terms.

The following is a description of the major non-confidential terms of the PPA. The market-sensitive proprietary PPA terms are described in Confidential Appendix A of this Application. Capitalized terms have the meaning ascribed to them in the PPA, unless otherwise stated. Please refer to Appendix A of the CAISO Tariff for the definition of CAISO terms.

1. Type of Purchase. The PPA is a "hybrid" contract for dispatch rights and output from the capacity from three RPS-eligible resources (Rollins Powerhouse, Dutch Flat No.2 Powerhouse and Bowman Powerhouse) and one non-RPS eligible hydro resource (Chicago Park Powerhouse.)

2. Transaction/Product Type. PG&E will purchase all Product from the YB Project. Product includes all of the following and similar attributes – Energy, Capacity, Capacity Attributes, Ancillary Services from Chicago Park and Dutch Flat Powerhouse No. 2, and Green Attributes from Bowman, Rollins and Dutch Flat Powerhouse No. 2.[10]

3. Conditions Precedent and Date Triggers. The PPA will become effective once CPUC Approval has occurred, and either the new COA or Part II of the Consolidated Contract (i.e. the existing COA) as amended by the Parties, is in full force and effect.[11] The Initial Energy Delivery Date is July 1, 2013, subject to the satisfaction of all Conditions Precedent.

4. Key Contract Dates. Initial Energy Delivery Date, aka "Start of Delivery Term" for Chicago Park, Dutch Flat No. 2 and Rollins Powerhouse is July 1, 2013. The Conversion Date, i.e. the "Start of Delivery Term for Bowman Powerhouse" is January 1, 2017.

5. Transmission/Interconnection/CAISO Requirements. NID will pay for interconnection, obtain and comply with the requirements of the CAISO Large Generator

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[10] *Section .1(a) and definition of Product*

[11] (*Section 2.5 and definition of Delivery Term)*

Interconnection Plan ("LGIP") or other such agreement with the Participating Transmission Operator, execute a CAISO PGA, and cause interconnection and metering facilities to be maintained throughout the Delivery Term.[12]

6. **Scheduling Coordinator.** PG&E is the Scheduling Coordinator ("SC") for the YB Project. PG&E also has the option to designate a third-party SC, but must give prior notice to NID of such designation.[13]

7. **Delivery Term.** The delivery term is 20 Contract Years from the Initial Energy Delivery Date.[14]

8. **Capacity and Efficiency Performance Requirements.** NID must perform an Initial Capacity Test and an Initial Efficiency Test prior to the Initial Energy Delivery Date. PG&E has option to require NID to perform Capacity and Efficiency Testing during the Delivery Term. Adjustments to payments and contract capacity can result depending on the results of these tests.[15]

9. **Allocation of Congestion Risk.** Losses due to congestion from the delivery point to load center are borne by PG&E. If NID is exempted from or receives any refunds, credits or benefits from CAISO for congestion charges or Congestion Revenue Rights ("CRR"), NID must pass on those reductions to PG&E.[16]

10. **Outage Notification.** As SC, PG&E is responsible for securing CAISO approval of outages for NID. Seller is required to provide PG&E with notification sufficiently in advance to comply with CAISO requirements for forced and planned outages. Non-compliance may result in adjustments to payment and contract capacity.[17]

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[12] *Section 3.1(f)*

[13] *Section 3.4(b)*

[14] *Section 3.1(b)*

[15] *Section 3.1(d)(iii)*

[16] *Section 4.3(b)*

[17] *Section 3.7*

11. **Curtailment.** NID must reduce powerhouse output during any system emergency Curtailment Period per CAISO or participating Transmission Owner ("PTO") instructions.[18]

12. **WREGIS Certificate Transfers.** NID will ensure that all WREGIS Certificates associated with Delivered Energy from the ERR Powerhouse Resources are transferred to PG&E to satisfy RPS requirements.[19]

13. **FERC License.** If at any time after the Execution Date the conditions of NID's new long-term FERC license decrease the YB Project's expected generation by more than a pre-established threshold, then PG&E can calculate an appropriate reduction in payment.[20]

14. **Force Majeure Provisions.** PG&E is not required to make any payments for any Product that Seller fails to deliver or provide as a result of Force Majeure during the term of the Force Majeure. The non-performing party must provide the other party notice in the form of a letter describing in detail the Force Majeure claim within two weeks of the commencement of the Force Majeure. Parties must attempt to continue performance under the PPA to the extent possible during the event. Drought or dry year water conditions do not constitute Force Majeure.[21]

15. **Seller and Utility Termination Rights.** If the Conditions Precedent are not waived or satisfied within 240 days after an application for CPUC Approval is filed, then either Party may terminate the PPA. If either the Consolidated Contract or the Coordinated Operations and Water Conveyance Agreement are terminated because of a default under such contract, then the non-defaulting party under that contract may terminate the PPA.[22]

16. **Termination Due to Event of Default.** Events of Default include the failure to make a payment within the five-day notice period, a material misrepresentation, failure

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18 *Section 3.1(g)(iii)*

19 *Section 3.1(i)*

20 *Section 10.17*

21 *Section 3.7 (d)and definition of Force Majeure*

22 *Sections 11.1 and 11.2*

to perform a material obligation, bankruptcy, or unauthorized transfer of contractual obligation. If an Event of Default with respect to the Defaulting Party has occurred and is continuing, the other Party has the right to early termination of the PPA. Default provisions related to delivery guarantees are deleted because there is no Guaranteed Energy Production requirement in this PPA. Other standard RPS contract default provisions for existing facilities have been retained.[23]

17. Construction of New Powerhouse and Right of First Refusal or Rights of First Offer. If a New Powerhouse is completed during the Delivery Term, NID must convey to PG&E NID's first offer to sell all Products from the New Powerhouse under the same terms and conditions as the PPA, except for contract price, which must be quoted by Seller in the first offer. The Parties then have ninety days to enter into a PPA or amend the existing PPA to include the New Powerhouse, subject to CPUC approval. If PG&E refuses Seller's First Offer, NID may offer the output of New Powerhouse to a third party, provided that the material terms and conditions of any agreement with a Third Party are no more favorable to NID as compared to its first offer to PG&E.[24]

18. Extension of Contract Term. The delivery term may be extended for another ten years at the parties option (i.e., both Seller and Buyer must agree to extend) provided that NID has requested the extension at least two years before the end of the contract term, parties agree to the subsequent price and delivery term within six months of the request, and the amended PPA is approved by the Commission.[25]

D. Benefits of the YB Project.

As previously noted, the YB Project provides numerous benefits to PG&E and to the CAISO system.

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23 *Sections 5.1 and 5.2*

24 *Section 10.16*

25 *Section 10.18*

1. PG&E's Dispatch of the YB Project Will Allow Optimal Water Usage by the PG&E and NID Projects.

The YB Project is hydraulically linked with PG&E's DS Project. NID is also dependent on PG&E's Drum Switching Center to remotely dispatch its powerhouses. NID does not have its own control center for the YB Project and has no plans to establish its own control center. PG&E will be responsible for dispatching the YB Project's facilities, most likely for the entire term of the PPA.

PG&E and NID are engaged in coordinated planning and operation of the two projects, which facilitates maximizing the use of water for hydroelectric generation, recreational use, and meeting FERC license requirements. The two parties have taken steps to preserve the operating efficiencies that have developed during many years of operation, as demonstrated by their close cooperation on their respective applications for FERC license renewal. Any change in the license conditions of one hydro project has the potential to affect the operation of the other project. Thus, PG&E's continued dispatch and management of the YB Project as provided by the PPA is essential for preserving the optimal utilization of PG&E's own DS Project and the YB Project.

2. Procurement of the YB Project, Which is Located in a Resource-Deficient Local Area, Supports Local Reliability.

According to the CAISO's 2012 Local Capacity Technical Analysis, the YB Project is located in a capacity-deficient local area. Procurement under this contract will ensure that the capacity from the powerhouses continues to be offered into the CAISO market to meet load and reliability needs.

3. The YB Project is Highly Viable.

The YB Project is highly viable because the hydroelectric generation technology used by the NID powerhouses is well understood, existing equipment has been in use for decades, and some of the existing facilities have been operating for close to fifty years. The YB Project's facilities are remotely dispatched by PG&E's Drum Switching Center, so PG&E is familiar with the operations and capabilities of the YB Project. PG&E has found that the YB Project operates smoothly and is responsive to PG&E's dispatch and scheduling orders.

4. Availability for Dispatch.

The PPA provides PG&E with full rights to schedule generation, subject to the terms of the COA. The Chicago Park Powerhouse (38 MW) and the Dutch Flat Powerhouse No. 2 (26 MW)[26] can ramp up and down and respond to dispatch instructions subject to the hydrological constraints of each powerhouse. The ability to respond to contingencies in real time will become increasingly valuable over the twenty-year PPA term, as additional intermittent renewable resources come on-line in California.

5. Ancillary Services Capability.

The Chicago Park Powerhouse and Dutch Flat No. 2 Powerhouse can provide spinning and non-spinning reserves, which are critical for meeting CAISO ancillary services reserve requirements and maintaining reliability in the event of system contingencies. These reserves are available subject to the hydrological constraints of the YB Project and the DS Project.

6. Procurement Will Count Toward RPS Compliance Goals.

The three below-30 MW powerhouses are existing small hydro facilities from which PG&E procured electricity as of December 31, 2005. As such, they are eligible renewable energy resources, [27] and their generation will count toward PG&E's RPS obligations.[28] Based upon forecasts of generation under the expected terms of the new NID FERC license, approximately 133 GWh out of 282 GWh of total deliveries in an annual average hydro year will be generated by the RPS-eligible powerhouses of the YB Project (Dutch Flat No. 2, Rollins, and Bowman).

Project generation falls within the RPS statute's first portfolio content category, i.e., in-state generation from eligible renewable resources interconnected within the CAISO. At least 50% of PG&E's RPS deliveries must fall within this category during each RPS compliance period.[29] In addition, the twenty-year contract term qualifies the PPA as "long-term" RPS procurement; consequently, excess renewables procurement from the YB Project in one

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[26] Chicago Park Powerhouse has a ramp rate of 12.87 MW/min. Dutch Flat Powerhouse No.2 has a ramp rate of 3.87MW/min.

[27] Section 399.12(e)(1)(A).

[28] Section 399.12(h)(3)(A).

[29] Section 399.16(b)(1)(A).

compliance period can be applied to any subsequent RPS compliance period.[30] More information about the Project's RPS value is provided in Section E, below.

7. Comparison with other Non-RPS Eligible Dispatchable Local Resources.

Because the PPA procures both RPS-eligible and non-RPS eligible generation, a side-by-side comparison of the YB Project to PPAs delivering exclusively RPS-eligible or non-RPS-eligible power is not possible or particularly useful. PG&E is not aware of any hydroelectric project of comparable scale and scope that delivers a 50/50 blend of RPS-eligible/non-RPS-eligible power. However, a comparison of the PPA with PG&E's recently executed PPA with Placer County Water Authority ("PCWA"), and with contracts that are RPS-eligible, is provided in Confidential Appendix A.

III. CONSISTENCY WITH COMMISSION DECISIONS.

PG&E intends to credit the generation from the RPS-eligible powerhouses of the YB Project toward its obligation to procure electricity produced by eligible renewable energy resources, or its "RPS target."[31] The PPA satisfies all of the criteria used by the Commission to conclude that utility procurement of a renewable energy resource is reasonable and meets the criteria for procurement of non-RPS eligible resources as well.

A. RPS Valuation Criteria.

The value of this transaction as procurement of an RPS-eligible resource is demonstrated through the application of the least cost-best fit ("LCBF") criteria adopted by D.04-07-029. Since the YB Project is an existing interconnected facility, only the LCBF criteria applicable to electricity procurement from existing facilities are relevant. These criteria are limited to the market value and portfolio fit of the PPA.

1. Market Valuation.

PG&E undertakes the market valuation of a proposed PPA by using "mark-to-market analysis." Under this method, the present value of the contract payment stream is compared with

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[30] See, D.11-12-052, which interprets and applies Section 399.13(a)(4)(B)..

[31] Section 399.15(a).

the present value of the product's market value to determine the benefit (positive or negative) from the procurement of the resource, irrespective of PG&E's portfolio, to determine a net market value ("NMV") for the transaction. The project-specific values of the YB Project's market value constitute market-sensitive information. Further details of PG&E's analysis of the net market value of the PPA are addressed in Confidential Appendix A.

2. Portfolio Fit.

Portfolio fit considers how well an offer's features match PG&E's portfolio needs. The PPA provides a good match to PG&E's portfolio needs because deliveries from the YB Project are already integrated into PG&E's portfolio, are dispatchable, provide ancillary services, and occur in a capacity-deficient local area. Furthermore, the YB Project is essential to preserving the portfolio fit of PG&E's own DS Project. Due to the hydrological linkage between the YB Project and the DS Project, PG&E's loss of dispatch rights over the YB Project facilities may negatively impact PG&E's ability to optimally dispatch its own generation. Additional analysis of the YB Project's portfolio fit is provided in Confidential Appendix A.

B. Consistency with PG&E's Adopted RPS Procurement Plan.

PG&E's currently effective 2011 RPS Procurement Plan was filed on May 4, 2011 in compliance with D.11-04-030, and approved on May 11, 2011. The goal of PG&E's 2011 RPS Plan is to procure deliveries from eligible renewable energy resources totaling approximately one to two percent of PG&E's annual retail sales volume, or 800 to 1,600 GWh per year. The PPA enables PG&E to receive continued deliveries of RPS-eligible power from 40 MW of existing RPS-eligible small hydro resources that are well-integrated into PG&E's resource portfolio. The PPA assures PG&E continuity of generation from these renewable energy resources for another twenty years. Although the YB Project does not provide new RPS generation, it may allow PG&E to avoid the procurement of replacement RPS-eligible power at a higher cost.

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C. Consistency with the Commission's Decision Implementing RPS Portfolio Content Categories.

Senate Bill ("SB") 2 1X, which is codified at Sections 399.11, and following, established three portfolio content categories that apply to RPS-eligible generation associated with RPS procurement contracts signed after June 1, 2010. The Commission has recently issued guidance on how RPS procurement will qualify for inclusion in each of the new RPS categories. In each utility request for approval of an RPS procurement transaction signed after June 1, 2010, the transaction must be classified in accordance with its portfolio content category.[32] Procurement from the three smaller powerhouses, which are less than 30 MW in capacity, is procurement from an in-state RPS-eligible renewable energy resource that has its first point of interconnection with the CAISO. As such, the RPS-eligible procurement from the YB Project qualifies as procurement under the first portfolio content category specified in Section 399.16(b)(1)(A).

D. Compliance with RPS Standard Terms and Conditions.

Contracts for the purchase of electricity from eligible renewable energy resources must include the standard terms and conditions in D.04-06-014 and D.07-02-011, as modified by D.07-05-057 and D.07-11-025, and compiled and published in D.08-04-009. In addition, the non-modifiable term related to Green Attributes, which was finalized in D.08-08-028, must be incorporated within each RPS contract. The non-modifiable terms related to Tradable Renewable Energy Credits ("TRECs"), which were finalized in D.10-03-021, must be included only if applicable to the transaction.

The following table identifies the page and section number where the Commission's non-modifiable terms may be found within the PPA:

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[32] D.11-12-052 at p. 10.

Non-Modifiable Term	PPA Section No.	PPA Page No.
From Power Purchase Agreement		
STC 1: CPUC Approval	1.36	4
STC 2: Renewable Energy Credits ("REC") and Green Attributes	1.126	13
• **Definition of Green Attributes**	1.79	9
• **Conveyance of Green Attributes**	3.2	26
STC 6: Eligibility	10.2(b)	39-40
STC 17: Applicable Law	10.12	44
STC REC-1: Transfer of RECs	10.2(b)	40
STC REC-2: Tracking of RECs in WREGIS	3.1(h)(viii)	25

E. Clarification that the Non-Modifiable STC Do Not Apply to the Non-RPS Eligible Powerhouse.

The non-modifiable terms in the PPA conform exactly to the "non-modifiable" terms set forth in Attachment A of D.07-11-025 and Appendix A of D.08-04-009, as modified by D.08-08-028 and by Appendix C of D.10-03-021, except to clarify to the extent necessary that the output from the Chicago Park powerhouse is not RPS-eligible. Generally, the purpose of the non-modifiable terms is to ensure that the conditions for counting the purchased power toward Buyer's RPS obligation are met. This particular PPA procures generation from a large hydro facility, the Chicago Park powerhouse, as well as RPS-eligible small hydro facilities. Where it is necessary to explain that the output of the Chicago Park powerhouse is not being procured for compliance with PG&E's RPS obligations, or that the Chicago Park powerhouse is not an eligible renewable resource, two STCs have been modified only to the extent necessary to avoid mischaracterizing that facility as an eligible renewable energy resource.

1. STC 1.

The first affected term is STC 1, "CPUC Approval," PPA, Section 1.36 on page 4, which includes a finding that any procurement under the PPA will meet the Buyer's RPS procurement obligation. Since the Chicago Park Powerhouse is not RPS-eligible, the sentence, "To the extent procurement pursuant to this Agreement is from the Chicago Park Powerhouse, subsection (b) above shall not apply" has been inserted at the end of the non-modifiable term, as indicated below in bold, underlined font:

> 1.36 "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.
>
> **<u>To the extent procurement pursuant to this Agreement is from the Chicago Park Powerhouse, subsection (b) above shall not apply.</u>**

2. STC 6.

The other affected term is STC 6, "Eligibility," under which Seller warrants that the "Project" qualifies and is certified by the CEC as an Eligible Renewable Energy Resource, and that the "Project's" output delivered to Buyer qualifies under the requirements of the RPS. This term appears at PPA, Section 10.2(b) on pages 39-40.

As used in the PPA, the term "Project" includes all four powerhouses in order to be consistent with the terminology of the parties' Consolidated Contract and the Coordinated Operations and Water Conveyance Agreement currently under negotiation. Both of these agreements refer to the Yuba-Bear "Project" as an integrated operational entity. The carve-out of the Chicago Park Powerhouse from the definition of "Project" would have resulted in the term "Project" being used to refer to only three of the powerhouses in the PPA. This would have caused confusion for plant operators and others who commonly refer to both the operating agreement and the PPA. The parties agreed that the best solution was for Seller to warrant that the "Eligible Renewable Resource Powerhouse Resources" of the YB Project are RPS-eligible for the term of the PPA. The use of this term in STC 6 is highlighted in bold underlined font below:

> (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 **<u>ERR Powerhouse Resources of the</u>** Project qualif**<u>y</u>** and **<u>are</u>** certified by the CEC as Eligible Renewable Energy Resources ("ERRs") as such term is defined in Public Utilities Code Section 399.12 or Section 399.16; and (ii) the output of the **<u>ERR Powerhouse Resources</u>** 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.

The terms in the PPA that correspond to the "modifiable" standard terms and conditions drafted in D.07-11-025 and D.08-04-009 have been modified based upon the mutually agreed-upon-outcome of negotiations between PG&E and NID. The modifiable and non-modifiable standard terms for RPS contracts are highlighted in the version of the PPA provided in Confidential Appendix B. Each term of the PPA is an essential term of the negotiated agreement between the parties; therefore, the Commission should not modify any of the PPA's terms. The net benefits of the PPA for PG&E's customers result from the cumulative and interrelated terms of the entire PPA as a whole.

F. Market Price Referent ("MPR") and Above Market Funds ("AMFs").

The cost of power procured under the PPA is confidential, market-sensitive information which is protected from public disclosure by agreement of the parties. Although the actual PPA cost is confidential market-sensitive information, the PPA cost on a $/MWh basis is below the 2011 MPR established by Commission Resolution E-4442 on December 1, 2011, assuming average year hydrological conditions. The PPA does not qualify for AMFs under the standard established by Resolution E-4199 because its price is below the MPR, not the result of a competitive solicitation for RPS resources, and procures power from an existing resource. Complete PPA cost information is provided in Confidential Appendix A.

G. Approval of the PPA Supports PG&E's RPS Compliance Activities for California's 33% RPS Mandate.

Senate Bill 2 in the First Extraordinary Session of the 2011 Legislative Session ("SB 2 1X") increased California's RPS target to 33% of delivered energy from RPS-eligible facilities by 2020.

The YB Project is a valuable addition to PG&E's RPS procurement portfolio because its in-state renewable generation falls within the category of RPS procurement with the largest procurement target.[33] While the amount of RPS procurement as a percentage of retail sales grows in each compliance period, the percentage of renewable energy that must consist of generation having a first point of interconnection, or generation subject to dynamic transfer, with a California balancing authority escalates from 50% to 75% as well.[34] Because the PPA is for a term of twenty years, deliveries from the three RPS-eligible powerhouses that are in excess of the volumes required for any compliance period can be accumulated and applied to any subsequent compliance period.[35] Further details on PG&E's RPS compliance position and forecasting assumptions are provided in Confidential Appendix A.

H. Compliance with Other RPS Decisions.

Guidelines for the use of unbundled renewable energy credits to demonstrate RPS compliance were adopted in D.10-03-021. These guidelines are not relevant in this case, as the PPA does not involve the purchase of unbundled renewable energy credits. A process for obtaining approval of RPS contracts through the Tier 2 short-term "Fast Track" process was approved in D.09-06-050. This procedure is not applicable because the PPA is not being submitted under the Fast Track process.

In D.07-05-028, the Commission determined that in order to count energy deliveries from short-term contracts with existing facilities towards RPS goals, RPS–obligated LSE must contract for deliveries equal to at least 0.25% of their prior year's retail sales through long-term contracts

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[33] Section 399.16(c) (1).

[34] Sections 399.15(b)(2)(B) and 399.16(c) (1).

[35] Section 399.13((1)(4)(B).

or through short-term contracts with new facilities. The PPA is a long-term contract and, therefore, is not subject to the pro-rata limit on eligibility to contribute toward PG&E's RPS targets.

I. Consistency with Commission Guidelines for Bilateral Contracting.

The Commission has developed guidelines for how the utilities may enter into bilateral RPS contracts. In D.03-06-071, the Commission authorized entry into bilateral RPS contracts provided that such contracts did not require Public Goods Charge funds and were prudent.[36] In D.06-10-019, the Commission again held that bilateral contracts were permissible provided that they were at least one month in duration, were reasonable, and received Commission approval through the advice letter process. In addition, the Commission stated that bilateral contracts were not eligible for supplemental energy payments.[37]

The four requirements for Commission approval of bilateral RPS contracts were restated recently in a resolution approving a bilateral RPS contract executed by PG&E: (1) the contract is submitted for approval by advice letter; (2) the contract is longer than one month in duration; (3) the contract does not receive above-market funds ("AMFs"); and (4) the contract is deemed reasonable by the Commission.[38] The Commission noted that it would be developing evaluation criteria for bilateral contracts, but that the above four requirements would apply in the interim.[39]

On June 19, 2009, the Commission issued D.09-06-050, which established price benchmarks and contract review procedures for short-term and bilateral RPS contracts. D.09-06-050 provides that bilateral contracts should be reviewed using the same standards as contracts resulting from RPS solicitations.[40]

Although the YB Project includes both RPS-eligible and large-hydro resources, and would not literally be eligible to compete in an RPS solicitation, the PPA offers many compelling

[36] D.03-06-071 at 57-58.

[37] D.06-10-019 at 29 and 31.

[38] Resolution E-4216 at 5.

[39] *Id.*

[40] D.09-06-050 at 29.

benefits that would otherwise recommend it for selection. As previously noted, the fifty-year Yuba-Bear Project Power Purchase Contract under which PG&E procures 77 MW of contract capacity will expire next year. It was logical for the parties to engage in bilateral negotiations to continue the seller-buyer relationship, respectively, for mixed RPS-eligible and large-hydro NID powerhouse generation, particularly since the parties have been able to cooperatively manage these hydroelectric facilities for decades. These operational advantages impart a value to the YB Project that cannot be quantified and compared to RPS offers received through the RPS solicitation. Moreover, there are no established protocols for evaluating a hybrid resource, consisting of large hydro and RPS-eligible facilities, within the RPS Solicitation. These unique characteristics would have made the valuation and ranking of the YB Project against other participants in an RPS Solicitation a difficult task.

The PPA satisfies the requirements for the approval of bilateral PPAs, although it cannot be submitted by advice letter because it contains non-RPS-eligible deliveries. The PPA is not eligible for AMFs because it resulted from bilateral negotiations. The PPA has a twenty-year term and is, therefore, longer than one month in duration. Finally, the PPA is reasonable when considered against the standards used for evaluating contracts resulting from PG&E's 2011 RPS Solicitation, both with respect to price and other terms, as PG&E explains in this Application and in the attached Confidential Appendices.

J. Compliance with Interim Emissions Performance Standard.

The California Emissions Performance Standard ("EPS") as implemented by the Commission applies to a new contract commitment by a load serving entity for baseload generation with a delivery term of five or more years.[41] "Baseload generation" means electricity generation from a powerplant with an annualized plant capacity factor of at least 60%. The PPA is not a form of covered procurement subject to the EPS because the forecast annualized capacity factor of each of the hydroelectric facilities is less than 60%.

[41] *See*, D.07-01-039, Attachment 7.

K. Consistency with Bundled Procurement Plan.

The non-preferred capacity[42] under the PPA, which consists of the 38 MW capacity of the Chicago Park powerhouse, is subject to the "electric capacity procurement limits and ratable rates" in PG&E's Bundled Procurement Plan ("BPP"), which was adopted in D.12-01-033 and is being implemented by PG&E Advice Letter ("AL") 4026-E, as supplemented by AL 4206-E-A on May 20, 2012. The non-preferred capacity procurement under the PPA will not cause PG&E to exceed its electric capacity procurement limits in any delivery year associated with procurement that becomes effective in 2013. The mechanics of this limit are explained in more detail in Confidential Appendix A.

L. Independent Evaluator.

The Independent Evaluator ("IE") for PG&E's 2011 RPS Solicitation, Arroyo Seco Consulting, evaluated the PPA. The IE concluded that the negotiations with NID were conducted fairly, and based on the moderate to high valuation, low contract price, high viability, and moderate portfolio fit, the PPA merits CPUC approval. The findings of the IE are contained in Appendix C, public version, and Appendix C-1, confidential version.

M. Procurement Review Group Participation.

The Procurement Review Group ("PRG") for PG&E includes the Commission's Energy Division and Division of Ratepayer Advocates, Department of Water Resources ("DWR"), The Utility Reform Network ("TURN"), the California Utility Employees ("CUE"), and Jan Reid, as a PG&E ratepayer. The PRG was informed of the PPA on January 19, 2012. Additional information about this consultation is provided in Confidential Appendix A.

IV. REGULATORY PROCESS.

A. Requested Effective Date.

To ensure compliance with its BPP, PG&E respectfully requests the Commission to approve this Application at its second meeting in January 2013, but no earlier than December 1, 2012, so that the effective date of the PPA will occur in 2013. Under this timeline, PG&E will

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[42] Non-preferred capacity refers to capacity that is not procured pursuant to CPUC-approved Energy Efficiency or Demand Response Programs, the RPS program, CHP Program, or the various distributed generation programs.

not be at risk of exceeding the electric capacity procurement limits established in its BPP for procurement in any delivery year of the PPA.

B. Request for Confidential Treatment

In support of this Application, PG&E provides the following Appendices:

- **Confidential Appendix A** – Contract Summary and Analysis evaluating the benefits of the PPA based on confidential PPA terms;
- **Public Appendix B --** Power Purchase Agreement from which confidential market-sensitive terms have been redacted;
- **Confidential Appendix B-1** – Power Purchase Agreement containing confidential market-sensitive terms;
- **Public Appendix C -** Independent Evaluator's Report from which confidential market-sensitive terms have been redacted;
- **Confidential Appendix C-1 –** Confidential version of the Independent Evaluator's Report including market-sensitive terms concerning the fairness of PG&E's negotiations with NID and the merit of the transaction for CPUC Approval
- **Public Appendix D -** Balance Sheet and Income Statement of PG&E
- **Public Appendix E** – Summary of Earnings of PG&E.

Concurrent with the filing of this Application, PG&E has filed a separate motion seeking the issuance of the Commission's model protective order to protect confidential market sensitive information, as defined by Rulemaking ("R.") 05-06-040 and other proprietary business information from public disclosure. Information about the parties' negotiations is confidential pursuant to the confidentiality agreement executed by the Parties prior to the commencement of PPA negotiations. The relevance of the PPA with respect to PG&E's strategy for meeting its RPS net open position is market sensitive information. These matters, as well as contract terms revealing PG&E's valuation of the deal are discussed in Appendix A, "Contract Summary and Analysis." Generally, the PPA itself may be protected from public disclosure under the decisions in R.05-06-040; however, in this case, the PPA was subject to public review pursuant to the Brown Open Meeting Act because NID is a public agency.[43] However, price and other material terms related to the value of the transaction were redacted before the PPA was released. PG&E

[43] Govt. Code Section 54950, et seq.

has asked the Commission to preserve the continued confidentiality of this information where it appears in Appendix A, Appendix B-1, and Appendix C-1 in accordance with D.08-04-023.[44]

V. COMPLIANCE WITH THE COMMISSION'S RULES OF PRACTICE AND PROCEDURE.

A. Contents of Application (Rule 2.1).

1. Requested Relief.

PG&E requests the Commission to approve the PPA in its entirety, including payments to be made by PG&E, and to authorize PG&E to recover costs incurred pursuant to the PPA through a debit to its ERRA, subject only to the Commission's review of PG&E's administration of the PPA.

PG&E also requests the Commission to find that procurement from the RPS-eligible powerhouses under the PPA is procurement from an eligible renewable energy resource for purposes of determining PG&E's compliance with the RPS statute.

PG&E requests that the Commission approve the PPA in January of 2013, approximately six months from the date on which the Application is being filed.

2. Statutory Authority.

PG&E makes this request pursuant to the Commission's Rules of Practice and Procedure and seeks the above-stated relief pursuant to the following sections of the Public Utilities Code: Section 399.13(g) for recovery of RPS procurement costs; Section 399.15 for RPS procurement authorization; Section 399.16 for a finding that this PPA meets certain RPS procurement requirements; Section 451 for a finding that PPA procurement costs are just and reasonable; Section 454 for authorization to recover PPA costs in rates; Section 454.5 for upfront approval of the PPA as acceptable and eligible for rate recovery; Section 701 which confers plenary authority on the Commission to regulate every public utility within California; Section 728 under which the Commission may set just and reasonable rates; Section 729 which authorizes the Commission to

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[44] The Motion for Confidential Treatment is based upon D.08-04-023 and the August 22, 2006 Administrative Law Judge's Ruling Clarifying Interim Procedures for Complying with D.06-06-066 to demonstrate the confidentiality of the 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.

establish new rates based upon an investigation; and Section 8340, which establishes the greenhouse gas emissions performance standard for baseload electrical generating resources.

3. Legal Name and Principal Place of Business (Rule 2.1(a)).

The Applicant's legal name is Pacific Gas and Electric Company. PG&E's principal place of business is 77 Beale Street, San Francisco, California. Its post office address is P. O. Box 7442, San Francisco, CA 94120-7422. PG&E is a corporation organized under the laws of the state of California.

4. Correspondence and Communication Regarding This Application (Rule 2.1(b)).

Correspondence regarding this Application should be directed to PG&E's representatives in this matter, listed below:

Evelyn C. Lee, Law Department
PACIFIC GAS AND ELECTRIC COMPANY
P. O. Box 7442
San Francisco, CA 94120-7442
Telephone: (415) 973-2786
Facsimile: (415) 973-5520
E-Mail: ECL8@pge.com

Niels Kjellund, Energy Proceedings
PACIFIC GAS AND ELECTRIC COMPANY
P. O. Box 770000
San Francisco, CA 94177-0001
Telephone: (415) 973-7512
Facsimile: (415) 973-3574
E-Mail: NXK2@pge.com

5. Category of the Proceeding.

The Application should be categorized as a rate-setting proceeding.

6. Need for Hearing.

The Commission should approve the PPA without hearings, based on the information presented by PG&E in this Application.

7. Issues To Be Considered.

The following issues should be considered in this proceeding:

(a) Whether the PPA proposed in this Application is reasonable and in the best interest of PG&E's customers and thus should be approved by the Commission.

(b) Whether PG&E should be authorized to recover costs incurred pursuant to the above-listed contract in ERRA and to recover any stranded costs consistent with D.08-09-012.

(c) Whether certain procurement pursuant to the PPA is procurement from an eligible renewable energy resource for purposes of determining PG&E's compliance with its obligation under Section 399.11, et seq.; and

(d) Whether the PPA is in compliance with EPS requirements.

8. Proposed Schedule.

PG&E proposes the following schedule for Commission approval:

ACTIVITY	PROPOSED SCHEDULE
Application Filed	June 19, 2012
Application Noticed	June 22, 2012
Responses Filed	July 23, 2012
PG&E's Reply to Responses	August 2, 2012
Pre-Hearing Conference	August 17, 2012
Scoping Memo	August 27, 23012
Concurrent Opening Briefs Filed	September 28, 2012
Reply Briefs Filed	October 12, 2012
ALJ Proposed Decision Filed	December 12, 2012
Final Decision	January 17, 2013 (Estimated Date)

B. Organization and Qualification to Transact Business (Rule 2.2).

PG&E is, and since October 10, 1905 has been, an operating public utility corporation organized under California law. It is engaged principally in the business of furnishing electric and gas services in California. A certified copy of PG&E's Restated Articles of Incorporation, effective April 12, 2004, is on record before the Commission in connection with PG&E's Application 04-05-005, filed with the Commission on May 3, 2004. These articles are incorporated herein by reference pursuant to Rule 2.2 of the Commission's Rules.

C. Financial Statement (Rule 2.3).

The information required by Rule 2.3 subsections (a) through (h) is contained in PG&E's Fourth Quarter 2011 Consolidated Statements of Income and Consolidated Balance Sheets, which are attached as Appendix D to this Application.

D. Authority to Increase Rates (Rule 3.2).

PG&E does not propose to modify its electric rates in this Application. PPA procurement costs will be forecasted and included in the Electric Revenue Recovery Account ("ERRA"), subject to true-up and recovery through the ERRA rate. ERRA costs are not defined as rates for purposes of Public Utilities Code, Section 454. However, since authorization for the PPA is being sought by application instead of by advice letter, PG&E voluntarily provides the following material:

1. Balance Sheet (Rule 3.2(a)(1)).

PG&E's Fourth Quarter 2011 Consolidated Statements of Income and Consolidated Balance Sheets are provided as Appendix D to this Application.

2. Summary of Earnings (Rules 3.2(a)(5) and 3.2(a)(6)).

PG&E's revenues, expenses, rate base and rates of return summary for the recorded year 2010 are set forth in Appendix E to this Application.

VI. REQUESTED RELIEF.

PG&E respectfully requests the Commission to issue an order that:

1. Approves the PPA in its entirety, including payments to be made by PG&E pursuant to the PPA, subject only to the Commission's review of PG&E's administration of the PPA.

2. Finds that procurement from the three powerhouses with capacity less than 30 MW pursuant to the PPA is procurement from eligible renewable energy resources for purposes of determining PG&E'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.) ("RPS"), Decision ("D.") 03-06-071, D.06-10-050, and other applicable law.

3. Adopts a finding that deliveries from the three powerhouses with capacity less than 30 MW pursuant to the PPA shall count as procurement in the first portfolio content category as determined by Public Utilities Code section 399.16(b)(1)(A).

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4. Finds that all other procurement and administrative costs associated with the PPA are reasonable, approves such costs, and authorizes their recovery in rates pursuant to Public Utilities Code Section 399.13(g),

5. Concludes that the terms of the PPA, including the price of delivered energy, are reasonable.

6. Adopts the following finding of fact and conclusion of law in support of cost recovery for the PPA:

(a) The utility's costs under the PPA shall be recovered through PG&E's Energy Resource Recovery Account.

(b) Any stranded costs that may arise from the PPA are subject to the provisions of D.04-12-048 which authorize recovery of stranded renewables procurement costs over the life of the contract. The implementation of the D.04-12-048 stranded cost recovery mechanism is addressed in D.08-09-012.

7. Adopts the following finding with respect to resource compliance with the Emissions Performance Standard ("EPS") adopted in R.06-04-009:

> The PPA is not covered procurement subject to the EPS because the resources are hydroelectric facilities with a forecast capacity factor of less than 60 percent and, therefore, do not constitute baseload generation under paragraphs 1(a)(ii) and 3(2)(a) of the Adopted Interim EPS Rules, Attachment 7 of D.07-01-039.

8. Adopts the following finding with respect to compliance with PG&E's Bundled Procurement Plan ("BPP") adopted in D.12-01-033:

> Procurement under the PPA will not cause PG&E to exceed its electric capacity procurement limits in any delivery year associated with the PPA.

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9. Grants PG&E such other relief as the Commission finds to be just and reasonable.

DATED: June 20, 2012

Respectfully submitted,

CHARLES R. MIDDLEKAUFF
EVELYN C. LEE

By: ____________/s/*Evelyn C. Lee*______________
EVELYN C. LEE

Law Department
Pacific Gas and Electric Company
77 Beale Street, B30A-2467
San Francisco, CA 94105
Telephone: (415) 973-2786
Facsimile: (415) 973-5520
E-Mal: ECL8@pge.com

VERIFICATION

I, Roy M. Kuga , say:

I am an officer of Pacific Gas and Electric Company, a corporation, and am authorized, pursuant to Code of Civil Procedure § 446, ¶ 2, to make this Verification for and on behalf of said Corporation, and I make this Verification for that reason. I have read the foregoing Application, and I am informed and believe that the matters therein concerning Pacific Gas and Electric Company are true.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed on June 18, 2012 , at San Francisco, California.

/s/ Roy M. Kuga

ROY M. KUGA

Vice President - Energy Supply Management

Appendix A

Confidential

Contract Summary & Analysis

Nevada Irrigation District

(Not Included)

Appendix B

Redacted

NID-PG&E
Power Purchase Agreement

POWER PURCHASE AGREEMENT

Between

PACIFIC GAS AND ELECTRIC COMPANY
(as "Buyer")

and

NEVADA IRRIGATION DISTRICT
(as "Seller")

POWER PURCHASE AGREEMENT

TABLE OF CONTENTS PREAMBLE

GENERAL TERMS AND CONDITIONS

APPENDICES

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

Appendix I	Initial Energy Delivery Date Confirmation Letter
Appendix II	[Reserved]
Appendix III	Example of Calculation of CAISO Charges Under Section 4.2
Appendix IV	Project and Unit Descriptions Including Descriptions of Each Unit Site
Appendix V	Notification Requirements for Unit Capacity and Project Outages
Appendix VI	Resource Adequacy
Appendix VII	Notices List
Appendix VIII	Monthly Allocation Factor Table, Unit Allocation Factor, and Contract Year Price Table
Appendix IX	Calculation of Availability Adjustment
Appendix X	[redacted]
Appendix XI	Form of Letter of Concurrence
Appendix XII	Supplier Diversity Program
Appendix XIII	Certification of Third Party Agreement
Appendix XIV	Change in FERC License Conditions
Appendix XV	Unit Contract Capacity Reduction for Conveyance Failure

POWER PURCHASE AGREEMENT

PREAMBLE

This Power Purchase Agreement, together with the appendices and any other attachments referenced herein, is made and entered into between Pacific Gas and Electric Company, a California corporation ("Buyer" or "PG&E"), and Nevada Irrigation District, a California irrigation district organized and existing under the laws of California ("Seller" or "NID"), as of the Execution Date set forth on the signature page hereof. Buyer and Seller hereby agree to the following:

GENERAL TERMS AND CONDITIONS

ARTICLE ONE: GENERAL DEFINITIONS

1.1 "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.

1.2 "Agreement" means this Power Purchase Agreement between Buyer and Seller, which is comprised of the 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, "Governing Law", the word "agreement" shall have the meaning set forth in this definition. For the purposes of Section 3.1(i)(viii), the word "contract" shall have the meaning set forth in this definition.

1.3 "Amended PPA" has the meaning set forth in Section 10.18(b).

1.4 "Ancillary Services" means regulation (including load following) spinning reserves, non-spinning reserves, and replacement reserves (in each case as defined by the CAISO Tariff) associated with the Project or a given Unit, as applicable, and all other products deemed to be ancillary services by the CAISO or FERC as of the Execution Date or any future date during the Delivery Term.

1.5 "Arbitration" has the meaning set forth in Section 12.3.

1.6 "Availability Adjustment" has the meaning set forth in Appendix IX.

1.7 "Availability Multiplier" has the meaning set forth in Appendix IX.

1.8 "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.

1.9 "Betterment or Improvement" means any upgrade, improvement or addition to, or any expansion of, the Project or any Unit completed after the Execution Date that increases the generation capability of that Unit or the Project.

1.10 "Bowman Powerhouse" means the Bowman Unit described in Appendix IV.

1.11 "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 to whom the Notice, payment or delivery is being sent and by whom the Notice, payment or delivery is to be received.

1.12 "Buyer" has the meaning set forth in the Preamble.

1.13 "Buyer's Notice" has the meaning set forth in Section 10.16(b).

1.14 "Buyer's WREGIS Account" has the meaning set forth in Section 3.1(i)(i).

1.15 "CAISO" means the California Independent System Operator Corporation or any successor entity performing similar functions.

1.16 "CAISO Agreements Notice Date" has the meaning set forth in Section 2.8.

1.17 "CAISO Global Resource ID" means, for a given Unit, the number or name assigned by the CAISO for that Unit, which may be subject to change from time to time. Appendix IV lists the CAISO Global Resource ID for each Unit as of Execution Date.

1.18 "CAISO Grid" means the system of transmission lines and associated facilities of the Participating Transmission Owner that have been placed under the CAISO's operational control.

1.19 "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.

1.20 "California Renewables Portfolio Standard" means the renewable energy program and policies established by California State Senate Bills 1038 and 1078, codified in California Public Utilities Code Sections 399.11 through 399.20 and California Public Resources Code Sections 25740 through 25751, as such provisions are amended or supplemented from time to time.

1.21 "Capacity Attributes" means any current or future defined characteristic, certificate, tag, credit, or Ancillary Services attribute, whether general in nature or specific as to the location or any other attribute of the Project or a given Unit, intended to value any aspect of the capacity of the Project or a given Unit to produce Energy or Ancillary Services, including, but not limited to, any accounting construct so that the full Contract Capacity of a given Unit or the full Project's Contract Capacity, as applicable, 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.

1.22 "Capacity Test" means a test of a Unit's capacity to generate electrical energy performed in accordance with the Test Procedures and Section 3.1(d)(iii) and includes, without limitation, the Initial Capacity Test, any Seller's Initial Capacity Re-test, and any Capacity Tests performed during the Delivery Term.

1.23 "CEC" means the California Energy Commission or its successor agency.

1.24 "CEC Certification and Verification" means that the CEC has certified that the ERR Powerhouse Resources are each an ERR for purposes of the California Renewables Portfolio Standard and that all Energy produced by the ERR Powerhouse Resources qualifies as generation from an ERR.

1.25 "Chicago Park Powerhouse" means the Chicago Park Unit described in Appendix IV.

1.26 "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.

1.27 "Condition Precedent" means each of, or one of, the conditions set forth in Section 2.5(i) through (iii) and "Conditions Precedent" shall refer to all of the conditions set forth in Section 2.5(i) through (iii).

1.28 "Consolidated Contract" means that certain Consolidated Contract dated July 12, 1963 for the Drum-Spaulding Project, FERC Project No. 2310, and the Yuba-Bear Project, FERC Project No. 2266, entered into by and between PG&E and NID, as it may be amended by the Parties.

1.29 "Contract Capacity" means, for a given Unit, the generation capability of that Unit net of all auxiliary loads and station electrical uses as determined pursuant to Section 3.1(d).

1.30 "Contract Year Price" means the contract price specified for the applicable Contract Year in Appendix VIII.

1.31 "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.

1.32 "Conversion Date" means January 1, 2017.

1.33 "Conveyance Failure" means any failure of any portion of the physical infrastructure of the Drum-Spaulding Project or the Yuba-Bear Project that either (i) hinders, impedes or prevents the flow of water through any conveyance identified in Appendix XV as a result of an event of Force Majeure, or (ii) is a Seller Forced Conveyance Outage. For purposes of the Availability Adjustment in Appendix IX, in the event of a Conveyance Failure, the

Modified Capacity of an affected Unit shall be adjusted based on the reduction, expressed as a percentage, in such Unit's Contract Capacity as specified in Appendix XV.

1.34 "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.

1.35 "CPUC" or "Commission or successor entity" means the California Public Utilities Commission, or successor entity.

1.36 "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.

To the extent procurement pursuant to this Agreement is from the Chicago Park Powerhouse, subsection (b) above shall not apply.

1.37 "Curtailment 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 provides notice to a Party to curtail scheduled Energy for reasons including, but not limited to, (i) any system emergency, as defined in the CAISO Tariff ("System Emergency"), or (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;

(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, but not limited to, (i) any situation that affects normal function of the electric system including, but not limited to, 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 a Delivery Point; or

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

1.38 "Curtailment Period" means the period of time during which Seller reduces generation from a given Unit pursuant to a Curtailment Order.

1.39 "Day Ahead" means the twenty four (24) hour period prior to the operating day.

1.40 "Day Ahead Schedule" has the meaning set forth in the CAISO Tariff.

1.41 "Declared Contract Capacity" means, for a given Unit, the generation capacity designated for that Unit as specified in Appendix IV.

1.42 "Defaulting Party" means the Party that is subject to an Event of Default.

1.43 "Deficient Month" has the meaning set forth in Section 3.1(i)(v).

1.44 "Delivered Energy" means, for a given Unit, all Energy produced from that Unit, as measured in MWh at the CAISO revenue meter for the Unit based on a power factor of precisely one (1), including any Energy attributable to any Betterment or Improvement.

1.45 "Delivery Point" means, for a given Unit, the point at which Buyer receives Seller's Product from that Unit, as set forth in Section 3.1(c).

1.46 "Delivery Term" has the meaning set forth in Section 3.1(b).

1.47 "Disclosing Party" has the meaning set forth in Section 10.7.

1.48 "Disclosure Order" has the meaning set forth in Section 10.7.

1.49 "Distribution Upgrades" has the meaning set forth in the CAISO Tariff.

1.50 "Drum-Spaulding Project" means the Drum-Spaulding Hydroelectric Project, FERC Project No. 2310, owned and operated by Buyer.

1.51 "DUNS" means the Data Universal Numbering System, which is a unique nine character identification number provided by Dun and Bradstreet.

1.52 "Dutch Flat Powerhouse No. 2" means the Dutch Flat Unit described in Appendix IV.

1.53 "Early Termination Date" has the meaning set forth in Section 5.2.

1.54 "Effective Date" means the date on which all of the Conditions Precedent set forth in Section 2.5 have been satisfied or waived in writing by both Parties.

1.55 "Efficiency Rating Cure Period" has the meaning set forth in Section 3.1(d)(iii)(G)(ii).

1.56 "Efficiency Rating Cure Plan" has the meaning set forth in Section 3.1(d)(iii)(G)(ii).

1.57 "Efficiency Rating Deficiency" has the meaning set forth in Section 3.1(d)(iii)(G)(ii).

1.58 "Efficiency Test" means a test of a Unit's turbine efficiency performed in accordance with the Test Procedures and Section 3.1(d)(iii) and includes, without limitation, the Initial Efficiency Test, any Seller's Initial Efficiency Re-test, and any Efficiency Tests performed during the Delivery Term.

1.59 "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.

1.60 "Electric System Upgrades" means, for a given Unit, any Network Upgrades, Distribution Upgrades, or Interconnection Facilities that are determined to be necessary by the CAISO or Participating Transmission Owner, as applicable, to (i) physically and electrically interconnect that Unit of the Project to the Participating Transmission Owner's electric system for receipt of Energy at that Unit's Point of Interconnection (as defined in the CAISO Tariff) if connecting to the CAISO Grid and (ii) ensure the delivery of all Product from that Unit to Buyer as contemplated under this Agreement.

1.61 "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.

1.62 "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). For purposes of the definition of "Green Attributes", the word "energy" shall have the meaning set forth in this definition.

1.63 "ERR Powerhouse Resources" means the Rollins Powerhouse, the Dutch Flat Powerhouse No. 2, and, on and after the Conversion Date, the Bowman Powerhouse.

1.64 "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.

1.65 "Event of Default" has the meaning set forth in Section 5.1.

1.66 "Execution Date" means the latest signature date found on the signature page of this Agreement.

1.67 "Executive(s)" has the meaning set forth in Section 12.2(a).

1.68 "Extended Delivery Term" has the meaning set forth in Section 10.18.

1.69 "FERC" means the Federal Energy Regulatory Commission or any successor government agency.

1.70 "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 the Products 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.

1.71 "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 and to subsection (b) below, events that could qualify as Force Majeure include, but are not limited to, the following:

(i) flooding, lightning, landslide, earthquake, fire, 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) 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 a Unit, or making it impossible for the Transmission Provider to transmit Energy from the Project or a Unit, including Energy to be delivered pursuant to this Agreement from the Project or a Unit; provided that, if a curtailment of the Project or a Unit 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(g).

(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 operation or maintenance of the Project or a Unit (including any permit or approval for any Betterment or Improvement);

(iv) Seller's inability to obtain sufficient power or materials to operate the Project or a Unit, except if Seller's inability to obtain sufficient 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;

(v) 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;

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

(vii) 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;

(viii) 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; or

(ix) drought or dry year water conditions.

1.70 "Forced Outage" means, for a given Unit, any unplanned reduction or suspension of the electrical output from, or unavailability of, that Unit in whole or in part in response to a mechanical, electrical, or hydraulic control system trip or operator-initiated trip in response to an alarm or equipment malfunction and any other unavailability of the 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.

1.71 "Full Capacity Deliverability Status" has the meaning set forth in the CAISO Tariff.

1.72 "Full Capacity Deliverability Status Finding" shall mean, for a given Unit, a finding by the CAISO that such Unit meets the CAISO's requirements for deliverability at the Unit's Full Capacity Deliverability Status.

1.73 "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, without limitation, reference to information either available to it internally or supplied by one or more third parties, including, without limitation, 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 and 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.

1.74 "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.

1.75 "Good Utility Practice(s)" has the meaning provided in the CAISO Tariff.

1.76 "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, operation or maintenance of the Project or a given Unit, as applicable.

1.77 "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.

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

1.79 "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: (1) any avoided emission of pollutants to the air, soil or water such as sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO) and other pollutants; (2) 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] (3) 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

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[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.

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.

1.80 "Grid Management Charges" has the meaning set forth in the CAISO Tariff.

1.81 "Initial Capacity Test" means a Capacity Test performed prior to the Initial Energy Delivery Date pursuant to Section 3.1(d)(iii)(A).

1.82 "Initial Efficiency Test" means an Efficiency Test performed prior to the Initial Energy Delivery Date pursuant to Section 3.1(d)(iii)(A).

1.83 "Initial Energy Delivery Date" has the meaning set forth in Section 3.1(b).

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

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

1.86 "Instructed Operation" means (i) an Operational Order or (ii) a mandatory direction of the Transmission Provider, or a requirement under Seller's CAISO Participating Generator Agreement (explicitly incorporating Section 5 of the CAISO Tariff as in effect as of the Execution Date or any revision thereof), in order to meet emergencies and reliability needs including voltage support.

1.87 "Interconnection Customer's Interconnection Facilities" has the meaning set forth in the CAISO Tariff.

1.88 "Interconnection Facilities" has the meaning set forth in the CAISO Tariff.

1.89 "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.

1.90 "JAMS" means JAMS, Inc. or its successor entity, a judicial arbitration and mediation service.

1.91 "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 the definitions of "CPUC Approval" and "Green Attributes" and for Section 10.2(b), "Seller Representations and Warranties", and Section 10.12, "Governing Law", the term "law" shall have the meaning set forth in this definition.

1.92 "LGIA" means 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 Participating TO's Transmission System, including any description of the plan for interconnecting to the Participating TO's Transmission System.

1.93 "LGIP" means the Large Generator Interconnection Procedures set forth in the CAISO Tariff and associated documents; provided that if the LGIP is replaced by such other successor procedures approved by FERC governing interconnection (a) to the Participating TO's Transmission System or (b) of generating facilities with an expected net capacity equal to or greater than the Project's Contract Capacity, the term "LGIP" shall then apply to such successor procedure.

1.94 "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, without limitation, reference to information either available to it internally or supplied by one or more third parties including, without limitation, 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 and 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. "Losses" shall exclude any loss of Production Tax Credits, Energy Investment Tax Credits, or other federal or state tax credits, grants, or benefits related to the Project or any generation therefrom.

1.95 "Meter Service Agreement" has the meaning set forth in the CAISO Tariff.

1.96 "Manager" has the meaning set forth in Section 12.2(a).

1.97 "Major Maintenance" means, for a given Unit, an extended outage taken by that Unit that complies with the outage limitations as set forth in Section 3.7(b).

1.98 "MW" means megawatt (AC).

1.99 "MWh" means megawatt-hour.

1.100 "NERC" means the North American Electric Reliability Council or a successor organization that is responsible for establishing reliability criteria and protocols.

1.101 "Net Rated Output Capacity" means, for a given Unit, the Energy production capability of that Unit as measured at the Unit's CAISO revenue meter and as determined by a Capacity Test.

1.102 "Network Upgrades" has the meaning set forth in the CAISO Tariff.

1.103 "New Powerhouse" means any powerhouse constructed after the Execution Date that may be added to or become part of the Yuba-Bear Project.

1.104 "Non-Defaulting Party" has the meaning set forth in Section 5.2.

1.105 "Non-Summer Months" means the full calendar months of January, February, March, April, September, October, November, and December of a given calendar year.

1.106 "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). Appendix VII contains the names and addresses to be used for Notices.

1.107 "Obligor" means the Party breaching the terms of this Agreement.

1.108 "Operational Order" means a mandate or order issued by a Governmental Authority to Seller requiring Seller to offer or provide Product or to start up, shut down, curtail or operate the Project or any Unit for a specified period of time and for a specified purpose. An Operational Order includes, for example, a mandate issued by the U.S. Secretary of Energy to offer capacity or Energy or to operate the Project or any Unit during a declared governmental emergency. In contrast, by way of further example, a legal obligation to test the Project or any Unit for the purpose of maintaining any respective Governmental Approval is not an Operational Order.

1.109 "Operations Agreement" means the Consolidated Contract, as it may be amended by the Parties, or any such successor agreement under which the Parties coordinate and determine the operation of the Drum-Spaulding Project and the Yuba-Bear Project and which the Parties agree constitutes the Operations Agreement.

1.110 "Outage Notification Procedures" means the procedures specified in Appendix V. PG&E reserves the right to revise or change these procedures upon written Notice to Seller.

1.111 "Participating Generator Agreement" has the meaning set forth in the CAISO Tariff.

1.112 "Participating Transmission Owner" or "PTO" 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. For purposes of this Agreement, the Participating Transmission Owner is Pacific Gas and Electric Company.

1.113 "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.

1.114 "Planned Conveyance Outage" means any Work on any portion of the physical infrastructure of the Yuba-Bear Project that hinders, impedes or prevents the flow of water through any conveyance identified in Appendix XV that is part of the Yuba-Bear Project, and that complies with the annual planned outage schedule for conveyances as specified in the Operations Agreement. Any such Work on the Yuba-Bear Project that hinders, impedes or prevents the flow of water through any conveyance identified in Appendix XV that is part of the Yuba-Bear Project and that fails to comply with the above-described schedule in the Operations Agreement shall be deemed a Seller Forced Conveyance Outage.

1.115 "Planned Outage" means, for a given Unit, the removal of Unit 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 Schedule for the given Unit and comply with Section 3.7, and in Seller's sole discretion must be of the type that is necessary to reliably maintain the Unit, (b) cannot be reasonably conducted during operations of the Unit, and (c) has been reasonably approved by Buyer.

1.116 "PNode" has the meaning set forth in the CAISO Tariff.

1.117 "Point of Interconnection" has the meaning set forth in the CAISO Tariff.

1.118 "Preamble" means the paragraph that precedes Article One: General Definitions to this Agreement.

1.119 "Product" means all of the Energy, capacity, and all ancillary products, services, or attributes similar to the foregoing which are or can be produced by or associated with the Project or any Unit, as applicable, including, without limitation, renewable attributes, Renewable Energy Credits, Capacity Attributes, and Green Attributes.

1.120 "Project" means the Chicago Park Powerhouse, the Rollins Powerhouse, and the Dutch Flat Powerhouse No. 2, and, on and after the Conversion Date, the Bowman Powerhouse, together with the other assets, tangible and intangible, that compose each such powerhouse, including but not limited to the assets used to connect each powerhouse to its respective Point of Interconnection, all as more particularly described in Appendix IV, and any Betterment or Improvement. For purposes of the definition of "Green Attributes," the word "project" shall have the meaning set forth in this definition.

1.121 "Project's Contract Capacity" means the total sum of each Unit's Contract Capacity when added together.

1.122 "RA Capacity" means the maximum megawatt amount that the CAISO recognizes from the Project or a given Unit, as applicable, that qualifies for Buyer's Resource Adequacy Requirements and is associated with the Project or such Unit's Capacity Attributes.

1.123 "Reductions" has the meaning set forth in Section 4.3(b).

1.124 "Referral Date" has the meaning set forth in Section 12.2(a).

1.125 "Reliability Coordinator" has the meaning set forth in the CAISO Tariff.

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

1.127 "Replacement Capacity Rules" means a program set forth in the CAISO Tariff, as it may be amended, supplemented or replaced (in whole or in part) from time to time, setting forth certain requirements to replace Resource Adequacy capacity on planned outages.

1.128 "Resource Adequacy" means the procurement obligation of load serving entities, including Buyer, as such obligations are described in CPUC Decisions D.04-10-035 and D.05-10-042 and subsequent CPUC decisions 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.

1.129 "Resource Adequacy Requirements" has the meaning set forth in Section 3.3.

1.130 "RES-SIM Model" means the hydrological model used by the Parties and developed by HDR Consulting which provides expected generation profiles for the Yuba-Bear Project and the Drum Spalding Project for the purposes of supporting the renewal of the respective FERC license applications for the Yuba Bear Project and the Drum Spalding Project.

1.131 "Revised Offer" has the meaning set forth in Section 10.16(c).

1.132 "Rollins Powerhouse" means the Rollins Unit described in Appendix IV.

1.133 "Satisfaction Date" has the meaning set forth in Section 2.6.

1.134 "Schedule" has the meaning set forth in the CAISO Tariff.

1.135 "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.

1.136 "SEC" means the U.S. Securities and Exchange Commission.

1.137 "Seller" has the meaning set forth in the Preamble.

1.138 "Seller Excuse Hours" means, for a given Unit, those hours during which Seller is unable to make available all of the Contract Capacity of the Unit or to dispatch the Unit at Buyer's or CAISO's instructions as a result of (a) a Planned Outage event directly affecting that Unit to the extent that Seller has not exceeded the number of excused Planned Outage hours specified in Section 3.7(b) for the Unit, (b) Buyer's failure to comply with or perform any material covenant or obligation in this Agreement, (c) a Curtailment Order directly affecting the Unit, or (d) an Instructed Operation directly affecting the Unit.

1.139 "Seller's Deviation Period" has the meaning set forth in Section 4.2.

1.140 "Seller Forced Conveyance Outage" means any failure of any portion of the physical infrastructure of the Yuba- Bear Project that hinders, impedes or prevents the flow of water through any conveyance identified in Appendix XV that is part of the Yuba-Bear Project and that is not a Planned Conveyance Outage and is not the result of an event of Force Majeure.

1.141 "Seller's Initial Capacity Re-test" has the meaning set forth in Section 3.1(d)(iii).

1.142 "Seller's Initial Efficiency Re-test" has the meaning set forth in Section 3.1(d)(iii).

1.143 "Seller's WREGIS Account" has the meaning set forth in Section 3.1(i)(i).

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

1.145 "Settlement Interval" has the meaning set forth in the CAISO Tariff that currently refers to any one of the six ten (10) minute time intervals beginning on any hour and ending on the next hour (e.g. 12:00 to 12:10, 12:10 to 12:20, etc.), and that may be subject to change from time to time by the CAISO.

1.146 "Site" means, for a given Unit, the location of that Unit of the Project. Appendix IV describes the Site for each Unit of the Project.

1.147 "Summer Months" means the full calendar months of May, June, July, and August of a given calendar year.

1.148 "Switching Center" means PG&E's Drum Switching Center or any other switching center selected by Buyer in its sole discretion at any time during the Delivery Term.

1.149 "System Emergency" has the meaning provided in subsection (a) of the definition of "Curtailment Order".

1.150 "Term" has the meaning provided in Section 2.6.

1.151 "Terminated Transaction" means the Transaction terminated in accordance with Section 5.2 of this Agreement.

1.152 "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.

1.153 "Test Procedures" has the meaning set forth in Section 3.1(d)(iii)(D).

1.154 "Tested Efficiency Rating" means, for a given Unit, the efficiency rating of the Unit as determined by the applicable Efficiency Test for such Unit.

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

1.156 "Threshold Capacity" has the meaning set forth in Appendix IX.

1.157 "Transaction" means the particular transaction described in its entirety in Section 3.1(a) of this Agreement.

1.158 "Transmission Provider" means any entity or entities transmitting or transporting the Product on behalf of Seller or Buyer to or from a given Delivery Point. For purposes of this Agreement, the Transmission Provider is CAISO.

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

1.160 "Unit" means the Chicago Park Powerhouse, the Rollins Powerhouse or the Dutch Flat Powerhouse No. 2, or, on and after the Conversion Date, the Bowman Powerhouse, as applicable, together with the other assets, tangible and intangible, that compose such powerhouse, including but not limited to the assets used to connect the powerhouse to its Point of Interconnection, as more particularly described in Appendix IV, and any Betterment or Improvement to the applicable Unit.

1.161 "Unit Allocation Factor" means, for a given Unit, the percentage of the fixed payment for the applicable Contract Year that is allocated to that Unit, as specified in Appendix VIII.

1.162 "WECC" means the Western Electricity Coordinating Council or successor agency.

1.163 "WREGIS" means the Western Renewable Energy Generation Information System or any successor renewable energy tracking program.

1.164 "WREGIS Certificate Deficit" has the meaning set forth in Section 3.1(i)(v).

1.165 "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.

1.166 "WREGIS Operating Rules" means those operating rules and requirements adopted by WREGIS as of June 4, 2007, as subsequently amended, supplemented or replaced (in whole or in part) from time to time.

1.167 "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.

1.168 "Yuba-Bear Project" means the Yuba-Bear Hydroelectric Project, FERC Project No. 2266, owned and operated by Seller.

ARTICLE TWO: GOVERNING TERMS AND TERM

2.1 Entire Agreement. This Agreement 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" 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 to 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.

(i) Except where the context otherwise requires, "or" shall have the inclusive meaning frequently designated by "and/or".

(j) Examples shall not be construed to limit, expressly or by implication, the matter they illustrate.

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, but not limited to, orders or instructions relating to Electric System Upgrades and/or Curtailment Periods.

2.5 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 and Buyer has received a final and non-appealable order of the CPUC that finds that Buyer's entry into this Agreement is reasonable and that payments to be made by Buyer hereunder are recoverable in rates; and

(iii) The Operations Agreement is in full force and effect.

2.6 Term.

(a) The term shall commence upon the satisfaction of the Conditions Precedent set forth in Section 2.5 of this Agreement and shall remain in effect until the conclusion of the Delivery Term unless terminated sooner pursuant to Section 5.2, Section 11.1, or Section 11.2 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) (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; and (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.

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) Section 3.1(d)(iii) with respect to Seller's obligation to perform, for each Unit, an Initial Capacity Test and an Initial Efficiency Test as provided in such Section;

(ii) Sections 3.1(e)(ii) and (e)(iii);

(iii) Section 3.7(b)(i)(A);

(iv) Sections 5.1(a)(iv) and (v);

(v) 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;

(vi) Sections 5.2 through 5.7;

(vii) Sections 10.2, 10.6 through 10.8, Sections 10.12 through 10.15, and Section 10.17;

(viii) Section 11.1; and

(ix) 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.

2.8 Seller's CAISO Agreements.

(a) No later than April 1, 2013, the following CAISO agreements shall be in full force and effect between the CAISO and Seller:

(i) a CAISO Participating Generator Agreement (or successor or similar form of agreement providing for interconnected operation with the CAISO) for the Project or for each Unit, as required by the CAISO;

(ii) a CAISO Meter Service Agreement (or successor or similar form of agreement) for the Project or for each Unit, as required by the CAISO; and

(iii) a CAISO LGIA (or successor or similar form of agreement) for the Project and any other required agreements with the CAISO to allow for interconnection of each Unit of the Project to the CAISO Grid.

(b) Seller shall notify Buyer that each of the CAISO agreements described in Section 2.8(a) has been obtained and is effective with the CAISO promptly following the date upon which all such agreements become effective ("CAISO Agreements Notice Date").

2.9 Bowman Powerhouse CAISO Revenue Meter. No later than October 1, 2016, the requisite CAISO revenue meter for the Bowman Powerhouse shall be in place and operational in full compliance with the CAISO's requirements for such a meter ("Bowman Meter"). If the foregoing requirements have not been satisfied by the Conversion Date, then the Bowman Powerhouse shall be deemed to be fully unavailable and its Availability Adjustment shall be deemed to be zero until the date upon which all such requirements have been satisfied. Seller shall notify Buyer that the Bowman Meter has been installed and is operational promptly following the date that the Bowman Meter commences operation.

ARTICLE THREE: OBLIGATIONS AND DELIVERIES

3.1 Seller's and Buyer's Obligations.

(a) 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 each of the Delivery Points, and Buyer shall pay Seller the Monthly Payment Amount in accordance with the terms of this Agreement. In no event shall Seller have the right (i) to procure any element of the Product from any source other than the Project or any given Unit for sale or delivery to Buyer under this Agreement or (ii) sell Product or any portion thereof to a third party. Seller shall be responsible for any costs or charges imposed on or associated with the Product or the delivery of the Product up to and at each Delivery Point. Buyer shall be responsible for any costs or charges imposed on or associated with the Product after its receipt from each Delivery Point. Each Party agrees to act in good faith in the performance of its obligations under this Agreement.

(b) Delivery Term. The Parties shall specify and agree to the period of Product delivery for the "Delivery Term," as defined herein, by checking one of the following boxes:

☐ Delivery shall be for a period of ten (10) Contract Years.

☐ Delivery shall be for a period of fifteen (15) Contract Years.

X Delivery shall be for a period of twenty (20) Contract Years.

☐ Non-standard Delivery shall be for a period of ____ Contract Years.

As used herein, "Delivery Term" shall mean the period of Contract Years specified above beginning on the first date that Seller delivers Product to Buyer from the Project ("Initial Energy Delivery Date") in connection with this Agreement and continuing until the end of the twentieth (20th) Contract Year unless earlier terminated as provided by the terms of this Agreement. The Initial Energy Delivery Date shall be July 1, 2013 provided that (i) all of the Conditions Precedent in Section 2.5 have been satisfied or waived in writing and (ii) Seller has obtained the requisite CEC Certification and Verification for the Rollins Powerhouse, the Dutch Flat Powerhouse No. 2, and the Bowman Powerhouse. 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 I on or no later than two (2) calendar days following the occurrence of the Initial Energy Delivery Date. Part I (entitled "Yuba-Bear Project Power Purchase Contract") of the Consolidated Contract shall terminate on the Initial Energy Delivery Date.

(c) Delivery Point. The Delivery Point for a given Unit shall be the Point of Interconnection designated by the CAISO for that Unit. The Point of Interconnection for each Unit as of the Execution Date is specified in Appendix IV.

(d) Contract Capacity and Efficiency.

(i) Throughout the Delivery Term, Seller shall sell all Product produced by the Project or a given Unit solely to Buyer.

(ii) Contract Capacity. The Contract Capacity of a given Unit shall be the lower of the following for such Unit: (A) the Declared Contract Capacity of the Unit as specified in Appendix IV; or (B) the Net Rated Output Capacity of the Unit as determined pursuant to Section 3.1(d)(iii) below.

(iii) Capacity and Efficiency Testing Requirement.

(A) Initial Tests. Following the Execution Date and within the one hundred eighty (180) day period prior to the Initial Energy Delivery Date, Seller shall conduct an Initial Capacity Test and an Initial Efficiency Test of each Unit at Seller's expense. Seller shall have the right to perform a re-test of any Unit's Initial Capacity Test or Initial Efficiency Test ("Seller's Initial Capacity Re-test" or "Seller's Initial Efficiency Re-test", as applicable), at Seller's expense, no later than thirty (30) days following such Unit's Initial Capacity Test date or Initial Efficiency Test date, respectively, which re-test may occur after the Initial Energy Delivery Date. Buyer shall decide the date for the Initial Capacity Tests and the Initial Efficiency Tests and for any of Seller's re-tests, subject to Section 3.1(d)(iii)(D).

(B) Delivery Term Tests. During the Delivery Term, Seller shall conduct a Capacity Test and/or an Efficiency Test of a given Unit at Seller's expense if requested by Buyer, provided that Seller shall only be required to do so once each Contract Year for a given Unit. Buyer shall decide the date for any such tests, subject to Section 3.1(d)(iii)(D).

(C) Additional Tests. Notwithstanding clauses (A) and (B) of this subsection (iii), either Party may request one (1) additional Capacity Test and one (1) additional Efficiency Test of a given Unit each Contract Year, at its expense; provided that, a Seller's Initial Capacity Re-test and a Seller's Initial Efficiency Re-test of such Unit shall be deemed an additional test for the purposes of this subsection (C). Buyer shall decide the date for any additional tests, subject to Section 3.1(d)(iii)(D).

(D) Test Procedure and Timing. No later than thirty (30) days prior to Buyer's scheduled date for the Initial Capacity Tests and the Initial Efficiency Tests, the Parties shall develop and agree upon test procedures ("Test Procedures") to be used for the Initial Capacity Tests and Initial Efficiency Tests and for all subsequent Capacity Tests and Efficiency Tests. If the Parties cannot agree upon such Test Procedures by the deadline provided herein, then the Initial Capacity Tests and the Initial Efficiency Tests and all subsequent Capacity Tests and Efficiency Tests shall be conducted in accordance with ASME Performance Test Code 18. A Capacity Test or Efficiency Test shall only be conducted during periods in which hydrological conditions are reasonably expected to produce an accurate measurement of the tested Unit's capacity or efficiency, as applicable.

(E) Buyer's Witness of Tests. Buyer shall have the right to access the applicable Site and witness the conduct of any Capacity Test or Efficiency Test, including the Initial Capacity Tests and Initial Efficiency Tests. Seller shall provide Notice to Buyer at least five (5) Business Days prior to the test day of Seller's test schedule.

(F) Capacity Test Results. Seller shall provide Buyer with the results of each Capacity Test no later than five (5) Business Days after completion of the test.

i. The results of the Initial Capacity Tests and all subsequent Capacity Tests shall include supporting data sufficient to verify the validity of the test results.

ii. The results of the Initial Capacity Tests or of the most recent, undisputed Capacity Test shall set the Net Rated Output Capacity of the respective Unit for the purpose of determining the Contract Capacity for such Unit and shall be effective as of the date of Buyer's receipt of the applicable test results.

(G) Efficiency Test Results. Seller shall provide Buyer with the results of each Efficiency Test five (5) Business Days after completion of the test.

i. The results of the Initial Efficiency Tests and all subsequent Efficiency Tests shall include supporting data sufficient to verify the validity of the test results.

ii. The results of the Initial Efficiency Tests or of the most recent, undisputed Efficiency Test shall set, effective as of the date of Buyer's receipt of the applicable test results, the Tested Efficiency Rating of a given Unit. If at any point the Tested Efficiency Rating of a given Unit established during its Initial Efficiency Test or any subsequent Efficiency Test falls below 90% ("Efficiency Rating Deficiency"), Buyer shall send a Notice to Seller informing Seller of the Efficiency Rating Deficiency and, no later than ninety (90) days after Seller's receipt of such Notice from Buyer, Seller shall provide to Buyer a written plan and schedule ("Efficiency Rating Cure Plan") to rectify the Efficiency Rating Deficiency that is based on recommendations from a qualified independent California-licensed professional engineer.

Upon Buyer's receipt of the Efficiency Rating Cure Plan, Buyer shall send a Notice to Seller specifying that Seller has up to two (2) calendar years from the date of such Notice to implement the Efficiency Rating Cure Plan ("Efficiency Rating Cure Period"). On or before the last day of the Efficiency Rating Cure Period, Seller shall demonstrate to Buyer's reasonable satisfaction that Seller has cured the Efficiency Rating Deficiency of the applicable Unit by establishing that (1) Seller has satisfied its obligations under the Efficiency Rating Cure Plan, and (2) the Tested Efficiency Rating of such Unit is equal to or greater than 90% (such demonstration may include, at Buyer's election, the delivery by Seller to Buyer of a certification of Seller's satisfaction of the requirements in subparts (1) and (2) above, including all supporting data, from a qualified independent California-licensed professional engineer).

iii. If Seller has not demonstrated to Buyer's reasonable satisfaction a cure for an Efficiency Rating Deficiency by the end of the applicable Efficiency Rating Cure Period, then no later than ninety (90) calendar days following such period the Parties shall negotiate and agree upon a reduction to each Contract Year Price for the remainder of the Delivery Term. If after such ninety (90) day period, the Parties have not agreed upon a reduction to each such Contract Year Price for the remainder of the Delivery Term, then the Parties shall resolve the dispute in accordance with Article Twelve.

iv. Seller shall be responsible for all costs incurred to achieve and implement the Efficiency Rating Cure Plan.

(e) Project.

(i) All Product provided by Seller pursuant to this Agreement shall be supplied from the Project and the respective Units only.

(ii) Seller shall not make any alteration or modification to the Yuba-Bear Project, the Project or any Unit which results in (A) any reduction to the Contract Capacity or the anticipated output of any Unit without Buyer's prior written consent; or (B) any loss of the CEC certification of the Rollins Powerhouse, the Dutch Flat Powerhouse No. 2 or the Bowman Powerhouse each as an ERR, or the qualification of the output from each such Unit under the requirements of the California Renewables Portfolio Standard. Subject to the foregoing, Seller may increase the Contract Capacity or the anticipated output of a Unit with Buyer's prior written consent, not to be unreasonably withheld. The Parties may discuss additional agreements with respect to any such increase, each of which shall be subject to mutual agreement between the Parties and the approval of the CPUC and any other applicable Governmental Authorities. The Project is further described in Appendix IV.

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

(f) Interconnection Facilities and Seller Obligations. Seller shall (A) arrange and pay independently for any and all necessary costs under any interconnection agreement with the Participating Transmission Owner; (B) cause the Interconnection Customer's Interconnection Facilities, including metering facilities to be maintained; (C) comply with the procedures set forth in the LGIP and applicable agreements or procedures provided under the LGIP 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 Product from the Project and the respective Units up to and including quantities that can be produced utilizing all of the Project's Contract Capacity.

(g) Performance Excuses.

(i) Seller Excuses. Seller shall be excused from operating in accordance with Buyer's or the CAISO's instructions to dispatch a given Unit at the required level for the applicable time period during any Seller Excuse Hours for such Unit and during any event of Force Majeure affecting such Unit; provided that, the Modified Capacity of such Unit affected by an event of Force Majeure shall be adjusted in accordance with Appendix IX.

(ii) Buyer Excuses. The performance of Buyer to receive and/or pay for the Product from a given Unit shall only be excused through an Availability Adjustment as provided for in Appendix IX or by Seller's failure to comply with or perform any material covenant or obligation in this Agreement. For purposes of Appendix IX, there shall be no Availability Adjustment for any increase in Seller's consumptive use of water to meet the demands of Seller's customers located within its service area as now constituted, provided that any such increase is permitted under or provided for by Seller's water rights and the terms and conditions of the Operating Agreement.

(iii) Curtailment and Instructed Operations. Notwithstanding Section 3.1(a) and this Section 3.1(g), Seller shall reduce output from the affected Unit(s) during any Curtailment Period pursuant to a Curtailment Order, and shall operate the Units in accordance with Instructed Operations.

(iv) No Excuse. Except for a failure or curtailment resulting from a Force Majeure or during a Curtailment Period, the failure of electric transmission or distribution service shall not excuse performance with respect to either Party for the delivery or receipt of Product from any Unit to be provided under this Agreement.

(h) 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, but not limited to, 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 or a given Unit reasonably necessary to permit Buyer to comply with such requirements, if any.

(i) WREGIS. Seller shall, at its sole expense, 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 produced from the ERR Powerhouse Resources 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 for all Delivered Energy to Buyer. Seller shall comply with all Laws, including, without limitation, 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(i)(viii) provided that Seller fulfills its obligations under Sections 3.1(i)(i) through (vii) below. In addition:

(i) Prior to the Initial Energy Delivery Date, Seller shall register the ERR Powerhouse Resources with WREGIS and establish an account with WREGIS ("Seller's WREGIS Account"), which Seller shall maintain 1until 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 ERR Powerhouse Resources 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 produced from a given ERR Powerhouse Resource for such calendar month as evidenced by that ERR Powerhouse Resource'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(i). 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 produced from the ERR Powerhouse Resources for the same calendar month ("Deficient Month"). If any WREGIS Certificate Deficit in any month is caused, or is the result of any action or inaction, by Seller, then Seller shall deliver any WREGIS Certificate Deficit for such month to Buyer's WREGIS Account as soon as possible; provided that, if either Party finds that there exists a WREGIS Certificate Deficit one hundred twenty (120) or more days after the end of the calendar year in which such deficit pertains, then regardless of the cause of the deficit Seller shall reimburse Buyer [redacted] for each MWh of the WREGIS Certificate Deficit. 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(i), 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. l(i) after the Execution Date, the Parties promptly shall modify this Section 3.1(i) 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 produced from the ERR Powerhouse Resources 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.

(j) Access to Data.

(i) Commencing on the Initial Energy Delivery Date and continuing throughout the Delivery Term, Seller shall provide to Buyer, in a form reasonably acceptable to Buyer, the data set forth below; provided that, Seller shall make and bear the cost of any changes to any of the data delivery provisions below, as reasonably requested by Buyer, throughout the Delivery Term that Buyer determines are necessary to satisfy a CAISO requirement or instruction or for Buyer to perform its Scheduling Coordinator or settlements functions under this Agreement:

(A) real-time, read-only access to meteorological measurements from existing systems;

(B) real-time, read-only access to energy output information collected by the supervisory control and data acquisition (SCADA) system for each Unit, which shall be made available for review on a per Unit basis; provided that if Buyer is unable to access the SCADA system, then upon written request from Buyer, Seller shall provide energy output information 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) real-time, read-only access to each Unit's CAISO revenue meter(s) and all meter data related to each Unit and the Project as a whole; and

(D) net plant electrical output of each Unit at its respective CAISO revenue meter pursuant to Section 6.1 on a monthly basis.

(ii) Installation, Maintenance and Repair.

(A) 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(j)(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). 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 communication (i.e., cellular communications from onsite personnel, facsimile, blackberry or equivalent mobile e-mail) until the telecommunications link is re-established.

(iii) Seller agrees and acknowledges that Buyer may seek and obtain 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.

(k) Prevailing Wage.

(i) Seller shall use reasonable efforts to ensure that all Electricians hired under contract by Seller and its 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 or subcontractors to comply with or assume liability created by other inapplicable provisions of the California Labor Code.

(ii) To the extent applicable, Seller shall comply with the prevailing wage requirements of California Public Utilities Code Section 399.14, subdivision (h).

(l) Obtaining and Maintaining CEC Certification and Verification. Seller shall take all necessary steps including, but not limited to, making or supporting timely filings with the CEC to obtain and maintain CEC Certification and Verification for each of the ERR Resources throughout the Term.

3.2 Green Attributes. 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.

3.3 Reliability Obligations.

(a) Resource Adequacy. During the Delivery Term, Seller grants, pledges, assigns and otherwise commits to Buyer all of the Project's Contract Capacity, including Capacity Attributes from or associated with each Unit, to enable Buyer to meet its Resource Adequacy or successor program requirements, as the CPUC, CAISO or other regional entity may prescribe ("Resource Adequacy Requirements"). Seller agrees that during the Delivery Term Seller shall, at a minimum, comply with the terms set forth in Appendix VI to enable Buyer to use all of the capacity, including Capacity Attributes, to be committed by Seller to Buyer pursuant to this Agreement to meet Buyer's Resource Adequacy Requirements. Seller shall obtain and maintain Full Capacity Deliverability Status Finding by the CAISO for each Unit throughout the Delivery Term.

(b) 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 all outages pursuant to the provisions of Section 3.7. If Seller fails to provide any such Notice for a particular outage, then Seller shall be responsible for all costs, charges, expenses, penalties, and obligations resulting from the Replacement Capacity Rules for such outage.

(c) To the extent Seller has an exemption from the Replacement Capacity Rules under the CAISO Tariff, then Section 3.3(b) 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 an exemption shall not be an Event of Default and Buyer shall not have or be subject to any liability under this Agreement for such failure.

3.4 Transmission and Scheduling.

(a) Transmission.

(i) Seller's Transmission Service Obligations. During the Delivery Term:

(A) Seller shall 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 each of the Delivery Points for sale pursuant to the terms of this Agreement. Seller's interconnection, distribution and/or transmission arrangements shall provide for Full Capacity Deliverability Status for each Unit as of the Initial Energy Delivery Date and throughout the Delivery Term.

(B) Seller shall bear all risks and costs associated with such transmission service, including, but not limited to, any transmission outages or curtailment to each of the Delivery Points.

(C) Seller shall 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 each Unit to the CAISO Grid.

(ii) Buyer's Transmission Service Obligations. During the Delivery Term:

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

(B) Buyer shall bear all risks and costs associated with such transmission service, including, but not limited to, any transmission outages or curtailment from the Delivery Points.

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

(D) Subject to Section 4.2, Buyer shall be responsible for all CAISO costs and charges, electrical transmission losses and congestion at and from the Delivery Points.

(b) Scheduling Coordinator. Buyer shall act as the Scheduling Coordinator for the Project, unless Buyer elects to designate a Third Party SC in accordance with Section 3.4(b)(i)(B). In that regard, Buyer and Seller shall agree to the following:

(i) Designation as Scheduling Coordinator.

(A) At least ninety (90) calendar days before the Initial Energy Delivery Date, if requested by Buyer, 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.

(B) 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 costs, 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.

(C) 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 Delivery Term.

(ii) 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.

(c) Coordinated Planning and Operations.

(i) Except as expressly provided in this Agreement, the Operations Agreement shall govern the coordinated planning, operations and maintenance of the Yuba-Bear Project, the Drum-Spaulding Project, and the Project. Buyer shall have the exclusive right to bid or schedule all Product from each Unit and the Project, subject to the terms and conditions of the Operations Agreement, as Buyer deems prudent in its sole discretion.

(ii) Buyer and Seller shall share hydrologic information applicable to the Project, including precipitation, temperature, and runoff data and forecasts. Seller shall provide Buyer with Seller's plans for water withdrawals for non-generation uses, such as irrigation and domestic uses, and any other operating constraints. The Parties shall regularly confer on forecasts as snowfall, precipitation and runoff information become available. If either Party receives information through CAISO or directly from the Participating Transmission Owner regarding maintenance that will directly affect the ability to deliver Energy from the Project or any Unit, it will provide this information promptly to the other Party.

(iii) From time to time as reasonably determined to be necessary by the Parties, the Parties shall reasonably cooperate to confer and agree upon written operating procedures ("Operating Procedures") addressing how the Parties will coordinate the performance of their respective obligations under this Agreement, including, but not limited to: (1) the method of day-to-day communication relating to the operation of, and scheduling and dispatching, each Unit of the Project; (2) key personnel lists for each Party; (3) methods and procedures of collecting and sharing hydrologic data, and jointly developing and conferring on forecasts of runoff and operations schedules; (4) procedures for Forced Outage and Planned Outage scheduling and reporting, which shall be as described in <u>Appendix V</u> unless otherwise agreed by the Parties; (5) procedures for reporting daily reservoir levels; and (6) procedures for record keeping. Any failure to agree on Operating Procedures will not relieve either Party of its respective obligations under this Agreement.

3.5 <u>Standards of Care</u>.

(a) <u>General Operation</u>. Seller shall comply with the Operations Agreement and all applicable requirements of Law and the CAISO, NERC, WECC and FERC relating to the Project (including those relating to the construction, maintenance, ownership and/or operation of the Project and those required by Law to be performed by generators).

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

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

3.6 <u>Metering</u>. All Energy produced from a Unit must be delivered through that Unit's CAISO revenue meter, which must be dedicated exclusively to the Unit. Seller shall bear all costs relating to all metering equipment. 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 each Unit 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 for each Unit.

3.7 <u>Outage Planning and Notification</u>.

(a) <u>CAISO Approval of Outage(s)</u>. In its role as Scheduling Coordinator, Buyer shall be responsible for securing CAISO approval for Unit outages, including securing changes in its outage schedules when CAISO disapproves the proposed outage schedule or cancels previously approved outages. Buyer shall use commercially reasonable efforts to communicate CAISO approvals for Unit outages in a timely manner to Seller. Buyer shall be responsible for entering Unit outages in the Scheduling and Logging for ISO of California system (SLIC) or successor CAISO outage management systems.

(b) Planned Outages Notification and Restrictions.

(i) Throughout the Delivery Term, Seller shall notify Buyer of its proposed annual Planned Outage schedule for each Unit in accordance with Appendix V ("Planned Outage Schedule"), and such Planned Outage Schedule is subject to Buyer's approval, which approval may not be unreasonably withheld or conditioned. The Planned Outage Schedule notification timeline is as follows:

(A) Seller shall provide Notice of the Planned Outage Schedule for the next calendar year in the Delivery Term no later than July 1st of the prior calendar year, commencing July 1, 2012;

(B) Seller shall confirm a previously noticed Planned Outage schedule, provide Notice of a new proposed Planned Outage, or provide updates to a previously noticed Planned Outage schedule ninety (90) calendar days prior to the first day of the calendar month in which a Planned Outage is to occur, and such Notice shall cover the subject month and the following twelve (12) months within the Delivery Term;

(C) Seller shall provide Notice of any intra-month changes to the Planned Outage schedule no later than 10:00 AM on the day of the request and the earlier of fourteen (14) Business Days prior to the applicable operating day of the outage or two (2) Business Days prior to the CAISO deadline for submitting CAISO planned outages, provided that such intra-month request is subject to approval by Buyer in its sole discretion.

(ii) To the extent that Notice of any update or change is not provided in accordance with this Section 3.7(b) or not excused by Buyer, the applicable Unit shall be deemed unavailable to the extent such outage was not Noticed by the timeline specified in Section 3.7(b)(i) for the purposes of calculating Availability pursuant to Appendix IX, regardless of the CAISO's approval of such update or change.

(iii) Seller shall not conduct Planned Outages during the Summer Months. Planned Outages shall not exceed the following annual hourly maximum: 340 hours for Chicago Park Powerhouse; 340 hours for Dutch Flat Powerhouse No. 2; 410 hours for Rollins Powerhouse; and, after the Conversion Date, 340 hours for Bowman Powerhouse.

(iv) Notwithstanding Section 3.7(b)(iii), Seller shall be allowed to perform Major Maintenance on each Unit, which shall take place no more than once every five (5) years and shall total no more than 2,880 hours among all Units. Major Maintenance that complies with the limitations of this Section 3.7(b)(iv) shall be deemed a Planned Outage and not subject to an Availability Adjustment pursuant to Appendix IX.

(v) Buyer may grant exemptions to the foregoing restrictions if Buyer believes an additional outage is required and cannot be delayed to another date. Seller shall contact Buyer with any requested changes to a given Planned Outage Schedule if Seller believes a Unit must be shut down to conduct maintenance that cannot be delayed until the next scheduled

Planned Outage consistent with Good Utility Practices. Seller shall make reasonable efforts to complete Work during periods of Planned Outages in the shortest possible time in order to return the affected Unit(s) to normal operation. Seller shall not change its Planned Outage Schedule without Buyer's approval, not to be unreasonably withheld or conditioned. Seller shall not substitute Energy from any other source for the output of the affected Unit(s) during a Planned Outage. 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 orally notify the Switching Center of a Forced Outage of a Unit within ten (10) minutes of Seller's awareness of the Forced Outage and in accordance with the notification procedures set forth in Appendix V. Notification procedures for Forced Outages shall be subject to change from time to time by Buyer. Buyer shall put forth commercially reasonable efforts to submit such outages to CAISO.

(d) Force Majeure. Prior to the expiration of the second full Business Day subsequent to the 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, including the expected duration and effect of such event of Force Majeure. Failure to provide timely Notice constitutes a waiver of a Force Majeure claim. Promptly, but in any event within ten (10) days after a Notice is given as described above, the Parties shall meet to discuss the basis and terms upon which the arrangements set out in this Agreement shall be continued taking into account the effects of such Force Majeure event. Seller shall not substitute Product from any other source for the output of the Project or any Unit during an outage resulting from Force Majeure. 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. Each Party suffering a Force Majeure event shall take, or cause to be taken, such action as may be necessary to void, or nullify, or otherwise to mitigate, in all material respects, the effects of such Force Majeure event. The Parties shall take all reasonable steps to ensure resumption of normal performance under this Agreement after the cessation of any Force Majeure event. 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.

(e) Communications with CAISO. Buyer or Third-Party SC, in coordination with Seller, 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.

(f) Changes to Operating Procedures. Notwithstanding any language to the contrary contained in Sections 3.4, 3.6, 3.7 or 3.8 or Appendix V, 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 operating procedures described in the above-referenced sections are subject to change by Buyer from time to time and, upon receipt of Notice of any such changes, Seller agrees to work in good faith to implement any such changes as reasonably deemed necessary by Buyer; provided that such change does not result in an increase cost of performance to Seller hereunder other than *de minimis* amounts.

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, but not be limited to, information on power production, 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 shall have the right of ingress to and egress from the Project, each Unit and each Site on reasonable advance notice during normal business hours and for any purposes reasonably connected with this Agreement or the exercise of any and all rights secured to Buyer (i) in the Operations Agreement or by (ii) Law, or its tariff schedules, PG&E Interconnection Handbook, Electric Rule 21 (if PG&E is the Participating Transmission Owner), and rules on file with the CPUC.

ARTICLE FOUR: PRODUCT COMPENSATION; MONTHLY PAYMENTS

4.1 Product Compensation.

(a) During the Delivery Term, Seller's compensation for all Products delivered to Buyer shall be paid on a monthly basis ("Monthly Payment Amount") and determined pursuant to this Article Four. For purposes of determining the Monthly Payment Amount, the following definitions shall apply:

[redacted]

[redacted]

[redacted]

4.2 CAISO Charges during Forced Outages.

[redacted]

[redacted]

(iii) Notwithstanding Section 4.2(i) and 4.2(ii), Seller shall assume liability and reimburse Buyer for any and all CAISO costs, charges, and penalties incurred by Buyer as a result of Seller's actions or inactions. Buyer shall assume all liability and reimburse Seller for any and all CAISO costs and penalties incurred by Seller as a result of Buyer 's actions or inactions.

4.3 Additional Compensation.

(a) To the extent not otherwise provided for in this Agreement, in the event that Seller is compensated by a third party or receives any credits related to Electric System Upgrades contemplated in Section 3.1(f), Seller shall retain such compensation or credits.

(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 Reductions and Seller shall retain the Reductions.

ARTICLE FIVE: EVENTS OF DEFAULT

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 thirty (30) days after Notice;

(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, 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 or a Unit.

5.2 Declaration of Early Termination Date. 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 collect the Termination Payment for any Event of Default;

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

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

(d) suspend performance; and

(e) exercise any other rights or remedies available at Law or in equity to the extent otherwise permitted under this Agreement.

5.3 Calculation of Termination Payment.

(a) 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, without limitation, 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 obtained shall be: (a) for a like amount, (b) of the same Product, (c) at the same PNode or nearest liquid pricing point of the respective Unit, (d) for the remaining Delivery Term, and (e) any other commercially reasonable manner. For purposes of calculating Gains or Losses, the Availability Adjustment for each Unit shall be presumed to be the average of the Unit's Availability Adjustment for the twenty-four (24) months preceding the Early Termination Date, or the term of the Agreement if the Early Termination Date is less than twenty four months after the Effective Date.

(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 termination pursuant to Section 5.2, 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 five (5) 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.

ARTICLE SIX: PAYMENT

6.1 Billing and Payment; Remedies. On or about the tenth (10^{th}) day of each month beginning with the second month of the first Contract Year and every month thereafter, and continuing through and including the first month following the end of the Delivery Term:

(i) Seller shall provide to Buyer an invoice, in a format agreeable to Buyer, for the Monthly Payment Amount for the preceding month including adequate detail of the calculation of the Monthly Payment Amount and such invoice shall be subject to audit by Buyer;

(ii) Buyer shall provide to Seller an invoice for any CAISO charges or penalties for which Seller is responsible pursuant to Section 4.2, and any amount due to Buyer pursuant to Section 3.1(i)(v) ("WREGIS Certificate Deficit");

(iii) Seller shall provide to Buyer a record of metered data, in a format agreeable to Buyer, including CAISO metering and transaction data sufficient to document and verify the generation of Energy from each Unit for any Settlement Interval during the preceding month; and

(iv) Seller shall provide to Buyer access to any records that pertain to Reductions pursuant to Section 4.4, and Buyer shall net any Reductions from payments due to Seller in the month that the applicable records of the Reductions are received by Buyer.

If each Party is required to pay the other Party in the same month under this Agreement, then the Party owing the greater aggregate amount shall pay to the other Party the undisputed difference between the amounts owed. Payments under this Article Six shall be made on or before the later of the twenty-fifth (25^{th}) 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. 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. 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. 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. THE PARTIES CONFIRM THAT THE EXPRESS REMEDIES AND MEASURES OF DAMAGES PROVIDED IN THIS AGREEMENT SATISFY THE ESSENTIAL PURPOSES HEREOF.

FOR BREACH OF ANY PROVISION FOR WHICH AN EXPRESS REMEDY OR MEASURE OF DAMAGES IS PROVIDED, SUCH EXPRESS REMEDY OR MEASURE OF DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY, THE OBLIGOR'S LIABILITY SHALL BE LIMITED AS SET FORTH IN SUCH PROVISION AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED, UNLESS THE PROVISION IN QUESTION PROVIDES THAT THE EXPRESS REMEDIES ARE IN ADDITION TO OTHER REMEDIES THAT MAY BE AVAILABLE.

IF NO REMEDY OR MEASURE OF DAMAGES IS EXPRESSLY PROVIDED HEREIN, THE OBLIGOR'S 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 EXCEPT TO THE EXTENT PART OF AN EXPRESS REMEDY OR MEASURE OF DAMAGES HEREIN.

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.

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: FINANCIAL REPORTING 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 PG&E Corporation, a copy of PG&E Corporation's annual report containing audited consolidated financial statements for such fiscal year and (b) within sixty (60) days after the end of each of

PG&E Corporation's first three fiscal quarters of each fiscal year, a copy of PG&E Corporation's 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 www.pge-corp.com 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 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.

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 Points, including, but not limited to, ad valorem taxes and other taxes attributable to the Project, each Unit, land, land rights or interests in land for the Project or the Units. Buyer shall pay or cause to be paid all Governmental Charges on or with respect to the Product or the Transaction from the Delivery Points. 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 Buyer's payments to Seller, 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 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 operate and maintain the Project in the case of Seller;

(iii) 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;

(iv) 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;

(v) 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;

(vi) 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;

(vii) 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;

(viii) 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

(ix) 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 ERR

Powerhouse Resources of the Project qualify and are certified by the CEC as Eligible Renewable Energy Resources ("ERRs") as such term is defined in Public Utilities Code Section 399.12 or Section 399.16; and (ii) the output from the ERR Powerhouse Resources 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) Supplement to Seller Representations and Warranties. To the extent a change in Law occurs after execution of this Agreement that causes the representation and warranty set forth in Section 10.2(b) above to be materially false or misleading, Seller shall be deemed to have made commercially reasonable efforts to comply with such change in Law if Seller takes all actions to comply with or implement any change or improvement to the ERR Powerhouse Resources to maintain such certification or qualification ("RPS Qualification Improvement") which would require Seller to incur, in the aggregate, costs up to [redacted] (excluding Seller's administrative and internal staffing expenses that Seller would otherwise be obligated to pay) over the Term of this Agreement ("RPS Qualification Expenditure Maximum"). If after such change in Law has occurred, Seller determines that it will exceed the RPS Qualification Expenditure Maximum to implement the RPS Qualification Improvement, Seller shall notify Buyer and provide documentation and calculations to support the expected exceedence ("RPS Qualification Improvement Notice"). Buyer shall then have sixty (60) days after receipt of the RPS Qualification Improvement Notice to verify or dispute Seller's documentation and calculation. The Parties shall then have thirty (30) days to agree in writing (such agreement not to be unreasonably withheld, conditioned or delayed) on the amount by which Seller will exceed the RPS Qualification Expenditure Maximum in order to satisfy the RPS Qualification Improvement ("RPS Qualification Improvement Amount Agreement"). Buyer may then:

(i) elect to pay Seller the amount set forth in the RPS Qualification Improvement Amount Agreement and notify Seller of such election, subject to CPUC Approval (if required), within ten (10) Business Days of the effective date of the RPS Qualification Improvement Amount Agreement. If Buyer so elects, Seller shall, upon receipt of payment from Buyer, implement the RPS Qualification Improvement; or

(ii) elect not to pay Seller for the amount set forth in the RPS Qualification Improvement Amount Agreement and notify Seller of such decision within ten (10) Business Days of the effective date of the RPS Qualification Improvement Amount Agreement, in which case this Agreement shall continue in full force and effect and Seller shall not be required to implement any further or additional RPS Qualification Improvement.

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.

(ii) Seller covenants that it shall comply with all CAISO Tariff requirements applicable to an Interconnection Customer (as defined in the CAISO Tariff) and shall take any other necessary action, including but not limited to payment of fees and submission of requests, applications or other documentation, to promote the completion of the Electric System Upgrades, if any, prior to the Initial Energy Delivery Date or as soon as practicable thereafter.

(iii) Seller covenants that throughout the Delivery Term that it will take all reasonable steps consistent with Good Utility Practices to maintain the efficiency, condition, and/or proper functioning of all facilities and equipment pertaining to the Project.

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 Points. 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 the Delivery Points.

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 up to and at the Delivery Points, (ii) Seller's operation and/or maintenance of the Project or any Unit, or (iii) Seller's actions or inactions with respect to this Agreement, including, without limitation, 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 Points, including, without limitation, 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. 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, 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 in Connection with a Change in Control. Any direct or indirect change of control of Buyer or Seller (whether voluntary or by operation of Law) shall be deemed an assignment and shall require the prior written consent of the other Party, which consent shall not be unreasonably withheld.

(c) 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 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); or

(vi) in order to comply with *any* applicable regulation, rule, or order of the CPUC, CEC, or the FERC.

(b) If a Party is required to disclose confidential information in order to satisfy an obligation pursuant to subsection (a)(v) above ("Disclosure Order") each Party shall, to the extent practicable, use reasonable efforts: (i) to notify the other Party prior to disclosing the confidential information and (ii) prevent or limit such disclosure. After using such reasonable efforts, the Disclosing Party shall not be: (y) prohibited from complying with a Disclosure Order or (z) liable to the other Party for monetary or other damages incurred in connection with the disclosure of the confidential information. Except as provided in the preceding sentence, the Parties shall be entitled to all remedies available at Law or in equity to enforce, or seek relief in connection with, this confidentiality obligation. In addition to the foregoing, Seller shall provide timely Notice to Buyer of any request for Seller to disclose any of the non-public terms or conditions of this Agreement. If Buyer requests that Seller deny any such request, Buyer shall indemnify, pay all defense costs and hold Seller harmless for any and all loss incurred by Seller because if its denial of the request.

(c) Notwithstanding the provisions in Section 10.7(a), the Parties are permitted to disclose information related to the bidding and negotiation process as follows: (i) to PG&E's Procurement Review Group, as defined in California Public Utilities Commission ("CPUC") Decision (D) 02-08-071, subject to a confidentiality agreement, (ii) to the CPUC (including CPUC staff) under seal for purposes of review (if such seal is applicable to the nature of the Confidential Information), and (iii) to the Independent Evaluator, as defined and specified in the PG&E RPS Solicitation Protocol dated May 11, 2011 ("Protocol").

(d) 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 information related to this Agreement exchanged between the Parties as of and after the Effective Date.

10.8 <u>RPS Confidentiality</u>.

(a) Notwithstanding Section 10.7 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 those terms required by the CPUC in its then-current advice letter template, including the following: Party names, resource type, Delivery Term, Project location, capacity factor, Contract Capacity, Delivery Points, and applicability of the Energy Investment Tax Credit or Production Tax Credit.

(b) Seller acknowledges and agrees that pursuant to CPUC Decision D.06-06-066, which implements Senate Bill (SB) No. 1488 (2004 Cal. Stats., Ch. 690 (Sept. 22, 2004)), Buyer may make this Agreement publicly available. Seller further acknowledges that the CPUC's rules regarding confidential treatment of this Agreement are subject to change and therefore the timing and extent of disclosure is subject to amendment pursuant to CPUC order, rule or regulation.

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 its insurance coverage extant on the Execution Date for the Delivery Term in accordance with Good Utility Practice.

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. This Agreement shall be considered for all purposes as prepared through the joint efforts of the Parties and shall not be construed against one Party or the other as a result of the preparation, substitution, submission or other event of negotiation, drafting or execution hereof. 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. 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. The standard of review the FERC shall apply when acting on proposed modifications to this Agreement, either on FERC's own motion or on behalf of a signatory or a non-signatory, shall be the "just and reasonable" standard of review rather than the "public interest" standard of review. Nothing in this Agreement shall in any way restrict or otherwise limit the rights of either Party under Sections 205 and 206 of the Federal Power Act.

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 Purchase of Product from a New Powerhouse. If the construction of a New Powerhouse is completed during the Delivery Term, then neither Seller, its successors and assigns, nor its Affiliates shall enter into an obligation or agreement to sell or otherwise transfer any Product from that New Powerhouse to any third party except as permitted under this Section 10.16.

(a) Seller shall first offer, in writing, to sell to Buyer all Product from a New Powerhouse on the same terms and conditions, except for the contract price, as this Agreement ("First Offer"). Seller shall determine a contract price for the Products of the New Powerhouse and that shall also be included in the First Offer.

(b) If Buyer accepts the First Offer, Buyer shall Notify Seller within sixty (60) days of receipt of the First Offer ("Buyer's Notice"), 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, each being subject to CPUC Approval and rate recovery of all payments to be made by Buyer.

(c) If Buyer rejects or fails to accept Seller's First Offer, Seller shall thereafter be free to sell or otherwise transfer, and to enter into agreements to sell or otherwise transfer, any Product from the New Powerhouse 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 Seller desires to enter into such 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 such third party with more favorable material terms and conditions than those offered in the First Offer to Buyer. Seller's certificate shall be in substantially the form of Appendix XIII. 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, any Product from the New Powerhouse without first offering to sell or otherwise transfer the Product to Buyer on such more favorable terms and conditions ("Revised Offer") in accordance with subpart (b) above. If within thirty (30) days of receipt of Seller's Revised Offer 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 Product from the New Powerhouse to any third party on such terms and conditions as set forth in the certificate.

10.17 Change in FERC License Conditions. If at any time after the Execution Date, Buyer determines that the conditions of Seller's FERC license applicable to the Project are changed in a manner that decreases the Project's expected annual generation by more than ten percent (10%), then Buyer may calculate and apply an appropriate reduction to each Contract Year Price to account for the decrease. Buyer's calculation shall be based on a comparison of the final RES-SIM Model run used for FERC re-licensing purposes against the August 2011 RES-SIM Model run result as specified in Appendix XIV. The provisions of Article Twelve shall govern any dispute relating to Buyer's calculation.

10.18 Extension of Delivery Term. The Delivery Term shall be extended for an additional ten (10) Contract Years ("Extended Delivery Term") if all of the following conditions are satisfied:

(a) Seller requests an Extended Delivery Term by Notice to Buyer no later than July 1, 2031, and such Notice includes Seller's proposal for a contract price to be applied for the duration of the Extended Delivery Term; and

(b) Within six (6) months following Buyer's receipt of such Notice, the Parties amend the terms and conditions of this Agreement to account only for the change in the length of the Delivery Term and a mutually agreed upon change in the contract price for the Extended Delivery Term ("Amended PPA");

(c) Each Party agrees in its sole discretion to the Amended PPA; and

(d) CPUC Approval of the Amended PPA is obtained and Buyer receives a final and non-appealable order of the CPUC finding that Buyer's entry into the Amended PPA is reasonable and that payments to be made by Buyer under the Amended PPA are recoverable in rates.

ARTICLE ELEVEN: TERMINATION EVENTS

11.1 Failure to Meet All Conditions Precedent. If each Condition Precedent set forth in Section 2.5 is not satisfied or waived in writing by both Parties on or before two hundred forty (240) days from the date on which Buyer files this Agreement for CPUC Approval, 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, by reason of such termination under this Section 11.1; provided that the terms of Section 2.6 shall apply.

11.2 Operations Agreement. If, after the Effective Date of this Agreement, the Operations Agreement is terminated because of a default under such contract, then the non-defaulting party under that contract 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, by reason of such termination under this Section 11.2; provided that the terms of Section 2.6 shall apply.

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 Mediation. If the dispute cannot be resolved by negotiation as set forth in Section 12.2 above, then either Party may initiate mediation, the first-step of a two-step dispute resolution process, which JAMS shall administer. As the first step, the Parties agree to mediate any controversy before a commercial mediator from the JAMS panel, pursuant to JAMS's then-applicable commercial mediation rules, in San Francisco, California. Either Party may initiate such a mediation by serving a written demand for mediation. The mediator shall not have the authority to require, and neither Party may be compelled to engage in, any form of discovery prior to or in connection with the mediation. If within sixty (60) days after service of a written demand for mediation, or as extended by mutual agreement of the Parties, the mediation does not result in resolution of the dispute, then the Parties shall resolve such controversy through Arbitration by one retired judge or justice from the JAMS panel, which Arbitration shall take place in San Francisco, California, and which the Arbitrator shall administer 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 period commencing from the date of the written demand for mediation until the appointment of a mediator shall be included within the sixty (60) day mediation period. Any mediator(s) and arbitrator(s) 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 sixty (60) days of service of the written demand for mediation.

12.4 Arbitration. 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 V, 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, or contact to which Notice is to be given it by providing Notice of such change to the other Party.

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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:

NEVADA IRRIGATION DISTRICT, a COMPANY, California Irrigation District		**PACIFIC GAS AND ELECTRIC a California Corporation**	
Signature:	Ron Nelson	Signature:	
Name:	RON NELSON	Name:	Roy M. Kuga
Title:	GENERAL MGR	Title:	Vice President, Energy Supply Mgmt
Date:	MAY 9, 2012	Date:	5/8/2012

APPENDIX I

INITIAL ENERGY DELIVERY DATE CONFIRMATION LETTER

In accordance with the terms of that certain Power Purchase Agreement dated May ____, 2012 (“Agreement”) by and between Pacific Gas and Electric Company (“Buyer”) and Nevada Irrigation District (“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) Seller has scheduled and Buyer has received the Product from the Project, 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.

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:

NEVADA IRRIGATION DISTRICT	**PACIFIC GAS AND ELECTRIC COMPANY**
Signature: ______________________________	Signature: ______________________________
Name: ______________________________	Name: ______________________________
Title: ______________________________	Title: ______________________________
Date: ______________________________	Date: ______________________________

APPENDIX II

[Reserved]

APPENDIX III

EXAMPLE OF CALCULATION OF CAISO CHARGES UNDER SECTION 4.2

Appendix III - Section 4.2 (CAISO Charges during Forced Outages)

[redacted]

APPENDIX IV

PROJECT AND UNIT DESCRIPTIONS INCLUDING DESCRIPTIONS OF EACH UNIT SITE

PROJECT DESCRIPTION

The Project: Yuba Bear Project

Total number of Units at the Project prior to Conversation Date (committed to Buyer): **Three**

Total number of Units at the Project on and after the Conversation Date (committed to Buyer): **Four**

UNIT DESCRIPTION:

Unit Name: **Chicago Park Powerhouse**
[redacted]
Technology Type: **Large Hydro**
CAISO Global Resource ID: **CHICPK_7_UNIT 1**
PNode: **CHIPARK _7_B1**
Declared Contract Capacity: **40 MW**
Interconnection Details:
Congestion Zone: NP15
[redacted]
Delivery Point Address: 24199 Lowell Hill Road, Nevada City, CA 95959
Additional Information:
Ramp Rate:
Maximum Operational Ramp Rate: 12.87 MW/min
AGC Ramp Rate (if applicable): None
Ancillary Services (if applicable): **Spin, Non-Spin**
Other Operational Restrictions: Forebay is not to be operated below elevation of 10' or above 16'

Unit Name: **Dutch Flat Powerhouse No. 2**
Site: [redacted]
Technology Type: **Hydro (ERR Powerhouse)**
CAISO Global Resource ID: **DUTCH2_7_ UNIT 1**
PNode: **DTCHFLT2_7_B1**
Declared Contract Capacity: **26 MW**
Interconnection Details:
Congestion Zone: NP15
Physical Point of Interconnection: [redacted]
Delivery Point Address: 33199 Diggins Road, Nevada City, CA 95959
Additional Information:
Ramp Rate:
Maximum Operational Ramp Rate: 3.87 MW/min
AGC Ramp Rate (if applicable): None

Ancillary Services (if applicable): **Spin, Non-Spin**
Other Operational Restrictions: Dutch Flat After-bay isn't to be operated below elevation of 2729' with Dutch Flat Powerhouse No. 2 on line.

Unit Name: **Rollins Powerhouse**
Site: [redacted]
Technology Type: **Hydro (ERR Powerhouse)**
CAISO Global Resource ID: **ROLLIN_6 _UNIT**
PNode: **ROLLINSF_7 _B1**
Declared Contract Capacity: **13 MW**
Interconnection Details:
    Congestion Zone: NP15
    Physical Point of Interconnection: [redacted]
    Delivery Point Address: 15531 Arrowhead Lane, Grass Valley, CA 95945
    Additional Information:
Ramp Rate:
    Maximum Operational Ramp Rate: 0.1 MW/min
    AGC Ramp Rate (if applicable): None
Ancillary Services (if applicable): **None**
Other Operational Restrictions: Load increases that affect the Bear River below the Bear River Canal Diversion (PG&E's) have a ramping rate of "not to exceed a stage of .25' per hour or exceed 1' in six hours as measured at YB-196 located at the Hwy 174 Bridge over the Bear River below Rollins.

Unit Name: **Bowman Powerhouse**
Site: [redacted]
Technology Type: **Hydro (ERR Powerhouse)**
CAISO Global Resource ID: **BOWMAN_6 _UNIT**
PNode: **BOWMAN_7 _B1**
Declared Contract Capacity: 3.6 MW
Interconnection Details:
    Congestion Zone: NP15
    Physical Point of Interconnection: [redacted]
    Delivery Point Address:
    Additional Information:
Ramp Rate:
    Maximum Operational Ramp Rate: 3.6 MW/min
    AGC Ramp Rate (if applicable): None
Ancillary Services (if applicable): **None**
Other Operational Restrictions: Unit is block loaded based on downstream water demand.

APPENDIX V

NOTIFICATION REQUIREMENTS FOR UNIT CAPACITY AND PROJECT OUTAGES

A. NOTIFICATION REQUIREMENTS FOR ROUTINE START-UP AND SHUTDOWNS

Prior to paralleling or after disconnecting from the electric system, notify the Switching Center.

- Call the Switching Center and advise of the intent to parallel.
- Call the Switching Center after the Unit has been paralleled and report the parallel time and intended Unit output.
- Call the Switching Center after any routine separation.

B. SUBMISSION OF PLANNED OUTAGE INFORMATION AND UPDATES

1. Seller shall follow the below instructions for submittal of any request for Planned Outages. PG&E reserves the right to revise or change the procedures described in this Appendix V upon written Notice to Seller.

    a. For notification of annual Planned Outages, email to DAenergy@pge.com; PGOutageCoordination@pge.com; Bilat_Settlements@pge.com;

    b. For monthly updates to previously Noticed Planned Outages, email to DAenergy@pge.com; PGOutageCoordination@pge.com; Bilat_Settlements@pge.com;

    c. If Seller has daily updates to Unit availability or previously Noticed Planned Outages and such notification is to be made before the CAISO deadline for submitting Day-Ahead Schedules, call primary phone (415) 973-1971 or backup phone (415) 973-4500. Also send email to Bilat_Settlements@pge.com. Such notice, if not given by the timelines specified in Section 3.7(b), shall not be deemed an excused Planned Outage that is exempt from an Availability Adjustment unless Buyer grants such an exemption.

    d. If Seller has hourly updates to Unit availability or previously Noticed Planned Outages and such notification is to be made after the CAISO deadline for submitting Day-Ahead schedules, call PG&E's Real Time Desk at (415) 973-4500 and email to RealTime@pge.com; DAenergy@pge.com; Bilat_Settlements@pge.com. Such notice, if not given by the timelines specified in Section 3.7(b), shall not be deemed an excused Planned Outage that is exempt from an Availability Adjustment unless Buyer grants such an exemption.

    e. Please use the following email for submittal of all outages:

        i. Email subject Field: Delivery Date Range, Contract Name, Email Purpose (i.e. dd/mm/yyyy through dd/mm/yyyy XYZ Company Project #2 Outage Notification)

ii. ***Email body:***

1. ***Type of Outage: Planned 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, including, but not limited to, changes to a Planned Outage.***

C. FORCED OUTAGE REPORTING

1. Forced Outages – Seller shall notify the Switching Center orally within 10 minutes of awareness of such an event, if such conversation has not occurred between the Parties, or as soon as reasonably possible, after the safety of all personnel and securing of all facility equipment.

   a. Oral notification shall include time of Forced Outage, cause, current availability and estimated return date and time.

   b. Seller shall continually inform the Control Center of any updates to the Forced Outage and the status of the Project as soon as information becomes available.

   c. During the Delivery Term, Seller shall comply with any requests from the Control Center operators or Buyer for additional notification or reporting requirements for Forced Outages.

   d. Please use the following phone number for reporting Forced Outages:

   Drum Switching Center
   Phone: 530-389-2115

   e. Following oral notification to the Switching Center, Seller shall send an email notification in the format specified in this section(B)(i)(e) of this Appendix to the following groups: RealTime@pge.com; DAenergy@pge.com; Bilat_Settlements@pge.com.

APPENDIX VI

RESOURCE ADEQUACY

1. Seller and Buyer agree that throughout the Delivery Term the Parties shall take all commercially reasonable actions and execute any and all documents or instruments reasonably necessary to enable Buyer to use the RA Capacity to satisfy Buyer's Resource Adequacy Requirements. Such commercially reasonable actions may include, but are not limited to, the following. The Parties agree that this Appendix only supplements the obligations in the Agreement relating to Resource Adequacy and does not override or qualify such obligations in any way.

   A. Cooperating with and encouraging the regional entity, including the CAISO, if applicable, responsible for Resource Adequacy administration to certify or qualify each Unit's Contract Capacity for Resource Adequacy Requirements purposes. This includes following requirements the CAISO and/or CPUC has established and may establish in the future, including calculation of RA Capacity over all hours required for Resource Adequacy Requirement eligibility, and delivery of the RA Capacity to the Point of Interconnection for each Unit; and

   B. Negotiating in good faith to make necessary amendments, if any, to this Agreement to conform this Agreement to subsequent clarifications, revisions or decisions of the CPUC or any other entity, including the CAISO, with respect to Resource Adequacy.

2. Seller shall comply with the Resource Adequacy reporting requirements set forth in Section 40 of the CAISO Tariff as may be changed from time to time, including but not limited to the following:

   A. Taking all actions to register each Unit with the CAISO to ensure that each Unit's Capacity Attributes and/or Contract Capacity is able to be recognized and counted as RA Capacity;

   B. Coordinating with Buyer on the submission to the CAISO of the Monthly Resource Adequacy Plan, as defined in the CAISO Tariff;

   C. Complying with the dispatch requirements applicable to each Unit's resource type, as set forth in Section 40 of the CAISO Tariff; and

   D. Coordinating with Buyer with respect to the applicable reporting requirements, such as submitting Supply Plans to the CAISO.

3. RA Capacity Delivery Point. The delivery point for each Unit, with respect to Buyer's Resource Adequacy Requirements, shall be the Point of Interconnection of each Unit.

APPENDIX VII

NOTICES LIST

Name: Nevada Irrigation District, a California Irrigation District ("Seller")

All Notices:

Delivery Address:
Street: 1036 West Main St.
City: Grass Valley State: CA, 95945

Mail Address: (if different from above)

Attn: Ron Nelson

Phone: (530) 273-6185
Facsimile: (530) 273-6838

DUNS:
Federal Tax ID Number:

Invoices:
Attn: Accounting Department

Phone: (530) 273-6185
Facsimile: (530) 273-6838

Outages:
Attn: Travis Harrison
(Harrison@nidwater.com
Phone: (530) 273-8571 ext 14

Facsimile: (530) 273-5459

Payments:
Attn: Accounting Department
Phone: (530) 273-6185
Facsimile: (530) 273-6838

Wire Transfer:
BNK:
ABA:
ACCT:

Credit and Collections:
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) 973-5507

DUNS:
Federal Tax ID Number:

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

Day Ahead Desk:
Email: DAEnergy@pge.com

Phone: (415) 973-1971

Real Time Desk:

Phone: (415) 973-4500
Email: RealTime@pge.com

Switching Center (Drum)
Phone: 530-389-2115
Email: GTSHydroDrumPhOperation@pge.com

Wire Transfer:
BNK:
ABA:
ACCT:

Credit and Collections:
Attn: Justice Awuku

Phone:
Facsimile:

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

Phone: ______________________________
Facsimile: ___________________________

Manager, Credit Risk Management
Phone: (415) 973-4414
Facsimile: (415) 973-7301

Contract Manager:

Attn: Chad Curran (CRCq@pge.com)
Manager, Contract Management
Phone: (415) 973-6105
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

APPENDIX VIII

MONTHLY ALLOCATION FACTOR (MAF) TABLE, UNIT ALLOCATION FACTOR (UAF), AND CONTRACT YEAR PRICE TABLE

Month	Monthly Allocation Factor
Jan	[redacted]
Feb	
Mar	
Apr	
May	
Jun	
Jul	
Aug	
Sep	
Oct	
Nov	
Dec	
Totals	100.0%

<u>Unit Allocation Factor Prior to Conversion Date:</u>

Chicago Park Powerhouse: [redacted]

Rollins Powerhouse: [redacted]

Dutch Flat Powerhouse No. 2: [redacted]

<u>Unit Allocation Factor on and after the Conversion Date:</u>

Chicago Park Powerhouse: [redacted]

Rollins Powerhouse: [redacted]

Dutch Flat Powerhouse No. 2: [redacted]

Bowman Powerhouse: [redacted]

[redacted]

[redacted]

APPENDIX IX

CALCULATION OF AVAILABILITY ADJUSTMENT

acity": The "Threshold Capacity" of each Unit means the capacity level for that Uni

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

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.

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

Concurring Statement

On behalf of [Company Name], I am authorized to countersign this letter in concurrence with its content.

---

[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.

By: _______________
[Name]
[Company Position]
[Company Name]

APPENDIX XII

SUPPLIER DIVERSITY PROGRAM

1. Women-, Minority-, and service Disabled Veteran-owned Business Enterprises, as verified pursuant to the procedures prescribed in Section 2 of CPUC General Order 156 ("WMDVBE"), shall have the maximum practicable opportunity to participate in the performance of work supporting Seller's development of the Project.
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 development of the Project, and a statement setting forth any additional efforts Seller will employ to increase the participation of WMDVBE suppliers supporting development of the Project.
3. Upon request from Buyer, but no less than once per 365 day period of time between the execution of the Agreement and the Initial Energy Delivery Date, Seller shall report its spend with WMDVBE owned suppliers using PG&E's electronic reporting system located at: https://www.pgesupplierdiversity.com/pge/login.asp. To establish a user ID, Seller shall submit a request via email to the following address: supplierdiversityteam@pge.com.
4. Seller agrees that the obligations established through this Appendix XII are material obligations.

APPENDIX XIII

CERTIFICATION OF THIRD PARTY AGREEMENT

Pursuant to Section 10.16 of the Power Purchase and Sale Agreement dated ________________________ between Pacific Gas and Electric Company and Nevada Irrigation District ("Seller"), the undersigned representative of Seller hereby delivers this certificate. As required by Section 10.16, the material terms and conditions of Seller's proposed third-party agreement ("Third-Party Agreement") are as follows:

Price (describe any applicable escalation, adjustment and/or other key terms)

Energy Amount (annual), guaranteed and expected

Capacity Amount, guaranteed and expected

Delivery Term

Delivery Point

Form and Amount of Security

Date of Commencement of Delivery Term

Other Material Terms, including performance standards affecting any price or payment terms and events of default

I certify that the above summary is a truthful and accurate summary of all of the material terms and conditions of the Third-Party Agreement. I further certify that the Third-Party Agreement will not provide Seller with more favorable material terms and conditions than those offered in the applicable First Offer to Buyer, as defined in Section 10.16.

NEVADA IRRIGATION DISTRICT

By: ___________________________________

Name: _________________________________

Title: __________________________________

Date: __________________________________

APPENDIX XIV

CHANGE IN FERC LICENSE CONDITIONS

[redacted]

APPENDIX XV

UNIT CONTRACT CAPACITY REDUCTION FOR CONVEYANCE FAILURE

Table 1: In the event of a Conveyance Failure, the following reductions, expressed as a percentage, shall be used to determine the Modified Capacity of each affected Unit pursuant to Appendix IX ("Availability Adjustment Calculation").

[redacted]

Any failure to the conveyances in the Drum-Spaulding Project or Yuba-Bear Project **not** listed in Table 1 above shall have no impact to the Availability Adjustment calculation of the Units pursuant to Appendix IX.

Appendix C

Redacted

Independent Evaluator Report

Appendix C

Redacted

Independent Evaluator Report

ARROYO SECO CONSULTING

PACIFIC GAS AND ELECTRIC COMPANY BILATERAL CONTRACT EVALUATION

REPORT OF THE INDEPENDENT EVALUATOR ON A CONTRACT WITH NEVADA IRRIGATION DISTRICT

JUNE 19, 2012

TABLE OF CONTENTS

EXECUTIVE SUMMARY

This report provides an independent evaluation of the process by which the Pacific Gas and Electric Company ("PG&E") negotiated and executed a Power Purchase Agreement (PPA) with the Nevada Irrigation District ("NID") for the output of four of its hydroelectric powerhouses in the Sierra Nevada. The PPA covers delivery of both renewable energy (from NID's Bowman, Dutch Flat No. 2, and Rollins powerhouses, each a small hydro facility) and non-renewable energy (from NID's Chicago Park powerhouse, a large hydro facility).

This contract originated in an approach by NID to PG&E in late 2010, as it sought to deal with the impending expiry of existing contracts in 2013. An independent evaluator (IE), Arroyo Seco Consulting (Arroyo), conducted activities to review and assess PG&E's processes as the parties negotiated a new PPA.

The structure of this report follows the 2011 Independent Evaluator Report Template provided by the Energy Division of the CPUC. Topics covered include:

- The role of the IE;
- Adequacy of outreach for and robustness of the prior competitive solicitation;
- The fairness of the design of PG&E's least-cost, best-fit (LCBF) methodology;
- The fairness of PG&E's administration of its LCBF methodology;
- Fairness of project-specific negotiations; and
- Merit of the PPA for CPUC approval.

Arroyo's opinion is that the negotiations between PG&E and NID were, overall, conducted in a manner that was fair to ratepayers. Arroyo agrees with PG&E that the contract merits CPUC approval, based on an independently developed opinion that the contract will likely provide moderate to high net valuation and a low contract price; Arroyo regards the portfolio fit of the NID with PG&E's supply needs as moderate, and the project viability of the four powerhouses as high.

1. ROLE OF THE INDEPENDENT EVALUATOR

Pacific Gas and Electric Company issued a Request for Offers (RFO) on May 11, 2011, a competitive solicitation for power generation that qualifies as eligible renewable energy resources (ERRs) under the California Renewables Portfolio Standard Program.[1] The RPS Program was established by state law to ensure that retail sellers of electricity meet targets for procurement from ERRs as a percentage of annual retail sales.

The CPUC had conditionally approved PG&E's 2011 RPS procurement plan in its Decision 11-04-030 issued on April 14, 2011. This chapter elaborates on the prior CPUC decisions that form the basis for an Independent Evaluator's participation in the 2011 RPS RFO and in bilaterally negotiated contracts for RPS-eligible energy, describes key roles of the IE, details activities undertaken by the IE in this solicitation to fulfill those roles, and identifies the treatment of confidential information.

A. CPUC DECISIONS REQUIRING INDEPENDENT EVALUATOR PARTICIPATION

The CPUC first mandated a requirement for an independent, third-party evaluator to participate in competitive solicitations for utility power procurement in Decision 04-12-048 on December 16, 2004 (Findings of Fact 94-95, Ordering Paragraph 28). The CPUC required use of an IE when Participants in a competitive procurement solicitation include affiliates of investor-owned utilities (IOUs), IOU-built projects, or IOU-turnkey projects. The Decision envisaged that establishing an IE role would serve as a safeguard against anti-competitive conduct in the process of evaluating IOU-built or IOU-affiliated projects competing against Power Purchase Agreements (PPAs) with independent power developers.

In approving the IOUs' 2006 RPS procurement plans, the CPUC issued Decision 06-05-039 on May 25, 2006. This Decision expanded the CPUC's requirements, ordering that each IOU use an IE to evaluate and report on the entire solicitation, evaluation, and selection process, for the 2006 RPS RFO and future competitive solicitations. This requirement now applies whether or not IOU-owned or IOU-affiliate generation participates in the solicitation (Finding of Fact 20, Conclusion of Law 3, and Ordering Paragraph 8). This was intended by the CPUC to increase the fairness and transparency of the Offer selection process.

Decision 06-05-039 required the IE to report separately from the utility on the bid solicitation, evaluation, and selection process. Based on that Decision, the IE should provide a preliminary report along with the IOU submitting its short list.

Subsequently, as part of Rulemaking 08-08-009 to continue implementation of the RPS program, the CPUC issued Decision 09-06-050 on June 19, 2009. In that decision, the Commission concluded that long-term bilaterally negotiated RPS contracts should be governed by the same contract review processes and standards as contracts that arise

[1] The solicitation protocol was amended slightly on June 7, 2011 to alter the schedule for the RFO.

through competitive solicitations, including review by an Independent Evaluator. This serves as the basis for the requirement for an IE report about the NID contract, which has a twenty-year term. Note that the NID contract includes delivery of both RPS-eligible and ineligible energy to PG&E.

B. KEY INDEPENDENT EVALUATOR ROLES

To comply with the requirements ordered by the CPUC, PG&E retained Arroyo Seco Consulting to serve as IE for the 2011 competitive solicitation for renewable resources, providing an independent evaluation of the utility's Offer evaluation and selection process.

The CPUC stated its intent for participation of an IE in competitive procurement solicitations to "separately evaluate and report on the IOU's entire solicitation, evaluation and selection process", in order to "serve as an independent check on the process and final selections."[2] More specifically, the Energy Division of the CPUC has provided a template to guide how IEs should report on the 2011 RPS competitive procurement process, outlining four specific issues that should be addressed:

- Describe the IE's role;
- Did the IOU do adequate outreach to potential bidders, and was the solicitation robust?
- Was the IOU's LCBF methodology designed such that bids were fairly evaluated?
- Was the LCBF bid evaluation process fairly administered?

The structure of this report, setting out detailed findings for each of these issues, is organized around the template provided by the ED.

C. IE ACTIVITIES

To fulfill the role of evaluating PG&E's 2011 solicitation, several tasks were undertaken, both prior to Offer Opening and subsequently; these activities had direct application to the evaluation of the Nevada Irrigation District contract. Prior to Offer Opening on June 22, 2011, Arroyo performed several tasks to assess PG&E's methodology for evaluating Offers:

- Reviewed the solicitation and its attachments including PG&E's 2011 Form Agreements and description of the LCBF methodology and criteria.
- Examined the utility's nonpublic protocols detailing how PG&E would evaluate Offers against various criteria.
- Attended PG&E's Bidders' Conference on May 19, 2011 to evaluate the information provided to potential Participants, and how that information was distributed.

[2] CPUC Decision 06-05-039, May 25, 2006, "Opinion Conditionally Approving Procurement Plans for 2006 RPS Solicitations, Addressing TOD Benchmarking Methodology", page 46.

- Reviewed the list of registered attendees of the Bidders' Conference against PG&E's master list of RFO contacts (used for outreach to potential Participants).

- Reviewed the posting of questions and answers from the Bidders' Conference on PG&E's public website to check whether information that was made available in-person to conference attendees was also provided to other potential Participants.

- Examined PG&E's 2011 RFO master contact list; performed an analysis of contacts with respect to industry and technology representation.

- Interviewed members of PG&E's evaluation committee regarding details of the 2011 version of the utility's LCBF methodology and its inputs.

During the period between Offer Opening and PG&E's development of a final short list for submittal to the CPUC, Arroyo's activities included:

- Participating in opening Offers. Arroyo observed the opening of each Offer and observed the PG&E team logging in each Offer. The IE took an electronic copy of each Offer package, and independently built a database for tracking Offers.

- Reading portions of each Offer. Arroyo particularly scrutinized Offers for utility purchase. For PPA Offers, Arroyo focused on pricing, collateral, interconnection, permitting, technology, resource assessment, site control, and development and ownership experience descriptions in detail.

- Building an independent valuation model and using it to value Offers. This served as a cross-check against PG&E's LCBF model. The IE model used independent inputs and a different methodology than PG&E's. It was much simpler and lacked detail and granularity used in the PG&E model. However, the independent valuation was useful for testing the PG&E team's ranking of Offers using alternate assumptions.

- Attending PG&E's evaluation team discussions of Offers, criteria, issues, etc.

- Scoring Offers independently for viability, using the ED's 2011 version of the Project Viability Calculator. The independently developed Offer valuations and viability scores provided part of the basis for developing an independent view of the relative merit of Offers that the PG&E team selected or rejected.

- Reviewing PG&E's scoring of Offers for the criteria other than market valuation and project viability, testing for consistency and fairness in the treatment of projects.

- Attending meetings of PG&E's steering committee, as it made decisions about the logic for selecting a short list and approved proposed selections for the short list.

- Attending meetings of PG&E's Procurement Review Group (PRG), including answering questions about the solicitation and the Offers, and presenting an independent commentary and observations about the RFO.

- Offering PG&E's evaluation team and steering committee commentary based on independent opinion. In a few cases Arroyo provided specific suggestions on particular topics such as the feasibility of specific out-of-state transmission proposals.

Additionally, in order to prepare this report on the contract with Nevada Irrigation District, Arroyo pursued project-specific activities:

- Observed (telephonically) several negotiation sessions between utility staff and NID's commercial team;
- Reviewed draft term sheets, draft contracts, and other documents passed between the parties;
- Performed an independent valuation of the NID contract;
- Compared the net value and pricing of the NID contract to peer groups consisting of alternative proposals available to PG&E.

D. TREATMENT OF CONFIDENTIAL INFORMATION

The CPUC's Decision 06-06-066 detailed guidelines for treating confidential information in IOU power procurement and related activities, including competitive solicitations. The Decision provides for confidential treatment of "Score sheets, analyses, evaluations of proposed RPS projects", vs. public treatment (after submittal of final contracts) of the total number of projects and megawatts bid by resource type. Where the IE's reporting on the fairness of PG&E's selection of Offers requires explicit discussion of such analyses, scores, and evaluations, these are redacted from the public report.

2. ADEQUACY OF OUTREACH TO PARTICIPANTSAND ROBUSTNESS OF THE SOLICITATION

In its 2011 RPS solicitation, PG&E sought to meet a goal of procuring 1 to 2% of retail load by selecting Offers that will lead to negotiated contracts and commercially operating generating facilities. This section assesses the degree to which PG&E adequately conducted outreach activities to drum up sufficient participation in the RFO process, and the degree to which the resulting solicitation may be judged robust enough to be competitive.

A. CLARITY AND CONCISION OF SOLICITATION MATERIALS

While not really concise (it totals 53 pages excluding attachments, vs. Edison's 46 pages and SDG&E's 24 pages), Arroyo believes that the contents of PG&E's 2011 RPS RFO solicitation protocol generally provided clear and comprehensible direction to Participants on how to prepare and submit complete Offer packages that could be accepted and evaluated. Arroyo has a few observations about the clarity of the guidance provided in the protocol and issues created when Participants failed to understand or follow that guidance:

- Most Offers were submitted as complete and conforming packages. Common deficiencies in other Offers included:

    1. Failure to submit the offer form (Attachment D) for all Offer variants or phases;

    2. Errors in filling in the offer form, such as missing data, incomplete project description, or incomplete self-scored Project Viability Calculator;

    3. Use of a earlier draft version of Attachment D from the original posting of the RFO documents, rather than the one finalized on June 2, 2011 and posted on PG&E's public web site then;

    4. Failure to provide the text and data of the Offer in the requested Microsoft Word 2003 and Excel 2003 formats (as opposed to later versions or to Acrobat .pdf files);

    5. Corrupted data files;

    6. Failure to submit the hardcopies of the Offer as clearly requested in the protocol;

    7. Failure to submit a copy of a completed CAISO or PTO interconnection study in cases where the project had progressed to the point where such a study had been obtained. This requirement was explicitly stated in the solicitation protocol but widely ignored by Participants; and

8. In the case of projects outside California and not directly interconnecting to the CAISO, failure to specify how power would be delivered to a CAISO intertie point with a firm schedule, or what arrangements would be made to deliver to the CAISO.

Since requirements for the offer form were addressed in the solicitation protocol, in the instruction sheet for the offer form, and in the bidders' workshop presentation, Arroyo can only surmise that many Participants neglected to pay attention to these small but important details. Sending deficiency letters to Participants who failed to provide required information and obtaining corrections was time-consuming for all involved, but in most cases corrected documents were provided by the Participants and were accepted by PG&E. Arroyo cannot identify any specific improvements to the clarity of the RFO materials that might have reduced the incidence of such Participant errors, other than editing the instructions for attachment D (e.g. restating in the offer form instructions the need to Enable Macros in MS Excel) or walking through the form step by step in a section of the bidders' conference.

- The 2011 solicitation protocol stated at least four preferences of the utility that are not specifically among the evaluation criteria, including preferences for:

1. Projects considered bundled, in-state resources, over projects whose output will be considered renewable energy credits (RECs) for RPS compliance purposes;

2. Projects that deliver to CAISO nodes within the PG&E service territory, as opposed to the territories of other utilities (CAISO or otherwise) or to an interface point at the boundary of the CAISO;

3. Projects that contribute to PG&E's Resource Adequacy (RA) requirements, such as CAISO-interconnected projects with full deliverability, as opposed to energy-only projects in the CAISO or projects in other balancing area authorities for which deliverability or import capability of RA capacity throughout the contract term to PG&E has not yet been established.

4. Projects that offer flexibility in on-line date, given regulatory uncertainty affecting PG&E's need for RPS-eligible energy in 2014 and 2015.[3]

Based on comments provided in feedback sessions after the RFO, it appeared that several Participants were not aware of these stated preferences, perhaps because the description of the preference fell outside the chapter of the solicitation protocol that describes how Offers were to be evaluated. Arroyo recommends that in the future PG&E should edit the protocol to clarify that these specific preferences can play an important role in selection, even though they are not among the evaluation criteria. This would improve the transparency of the selection process to Participants.

[3] In PG&E's presentation at the bidders' conference, PG&E also expressed a preference that was not included in the solicitation protocol: "PG&E expects to focus on the latter part of the second (2014-2016) compliance period." It would have been helpful to state this preference clearly within the text of the protocol.

- The discussions that took place while debriefing non-shortlisted Participants after the RFO suggest that several developers did not understand the role of the Project Viability Calculator as a tool for assessing the likelihood that a proposed project could attain commercial operation and for screening proposals. Also, it is clear from how some Participants self-scored their projects that the Calculator's scoring guidelines provided by the ED are broadly misunderstood or misinterpreted.

  Several Participants did not or chose not to understand that the Calculator was designed such that the highest score for "project development experience" or "ownership/O&M experience" is assigned only if the development team has previously brought into operation at least two projects of the same technology and similar or larger MW capacity than that proposed. Some Participants could have improved their scores if they had read the guidelines more carefully and chosen to propose projects that could score higher based on those details. However, guidelines were provided in plain sight in the offer form. It is unclear how PG&E could have provided better guidance on how it uses the Calculator, beyond spending more time in the bidders' workshop walking through each criterion in the Calculator in detail.

Given the bulk of material that PG&E needs to provide in its protocol, it is not surprising that it exceeds fifty pages. Arroyo cannot identify any straightforward way to make the protocol more concise; the material provided is generally needed to provide Participants with a full and transparent view of how the solicitation will function and with full disclosure about obligations and constraints that govern Participants if they choose to proceed. One possibility would be to reduce the information required in Offers to focus more narrowly on data needed to establish eligibility and to perform the evaluation.

When the utility solicited feedback from non-shortlisted Participants after closing the solicitation, the sense of the feedback provided by developers was that PG&E's "solicitation was well organized" and "the most user-friendly of the three IOUs", that "the instructions were pretty clear", that in particular "the bidders' conference was very informative" and that the utility team's handling of questions and answers was responsive and helpful. Criticisms of the solicitation tended to focus on technical problems and burdensome nature of filling out the offer form, the priorities embedded in the Project Viability Calculator, the lack of transparency on what sort of projects were short-listed at what prices, the large volume and possible redundancy of information requested in the Offers, and that hardcopies of the Offer packages should not be required as opposed to electronic copies.

Overall, Arroyo believes that PG&E's solicitation materials were clear, if not particularly concise, and that improvement opportunities to help ensure that more complete Offer packages are submitted in the future are minor. Improvements could be helpful in streamlining the process and increasing Participants' satisfaction. Arroyo has some specific critiques regarding the solicitation protocol's lack of transparency about Offers for sites for development, described in the next chapter.

B. ADEQUACY OF OUTREACH

Here are some considerations used to evaluate whether PG&E performed successfully in reaching out to the community of renewable power developers:

- How many individuals were contacted? To what extent were these contacts in companies that develop renewable power?
- Was a diverse set of renewable technologies covered in the contacts, or was the outreach excessively focused on one or two technologies?
- How widely was information about the solicitation disseminated? Was information about the solicitation readily available to the public?
- To what extent did Participants appear well-informed about the details of the solicitation?

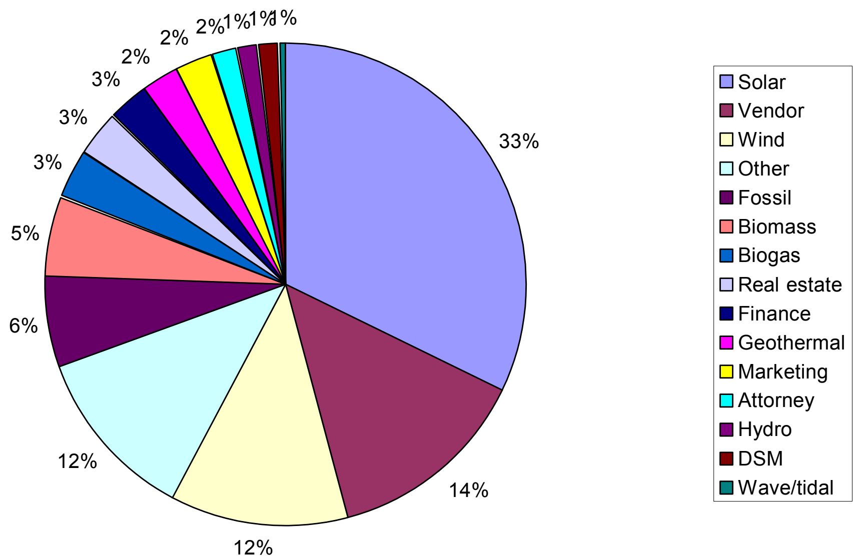
By May 2011, PG&E had compiled a general contact list for use in publicizing its RFOs, totaling more than 1,600 individuals; this is a significant increase from the version of the list used in the 2009 RPS solicitation, with closer to 1,100 contacts. PG&E appears to have been actively compiling contacts for outreach, including a contact list for the biogas industry.

When analyzed to attempt to assess which industries the contacts represented, the largest segment was made up of individuals active in the solar power sector, followed by wind power and biomass-based generation. Figure 1 displays the estimated shares by industry sector of these contacts. Note that this contact list is employed not just for renewable solicitations but for all-source RFOs as well.

Inspection of the contact list reveals that many of the major developers of renewable energy in North America are included, particularly among solar, wind, and geothermal developers. About 60% of the individual contracts represented organizations that could develop renewable generation or sell from existing facilities. Other contacts were with entities that provide services to renewable energy developers, such as attorneys, financing providers, consultants, equipment vendors, and wholesale marketers; it is unclear whether these providers sought to be on PG&E's RFO contact list in order to keep abreast of the solicitation or to develop business with renewable energy developers.

PG&E did not issue a press release to announce the issuance of the 2011 RPS RFO. However, news of the solicitation was picked up and reported in the electric power trade press, including publications such as Global Power Report, Megawatt Daily, Power, Finance, and Risk, and ReCharge. In addition, the detailed solicitation protocol and its attachments, the schedule, and other informational items were posted on PG&E's public website.

Figure 1. Breakdown of contact list by sector



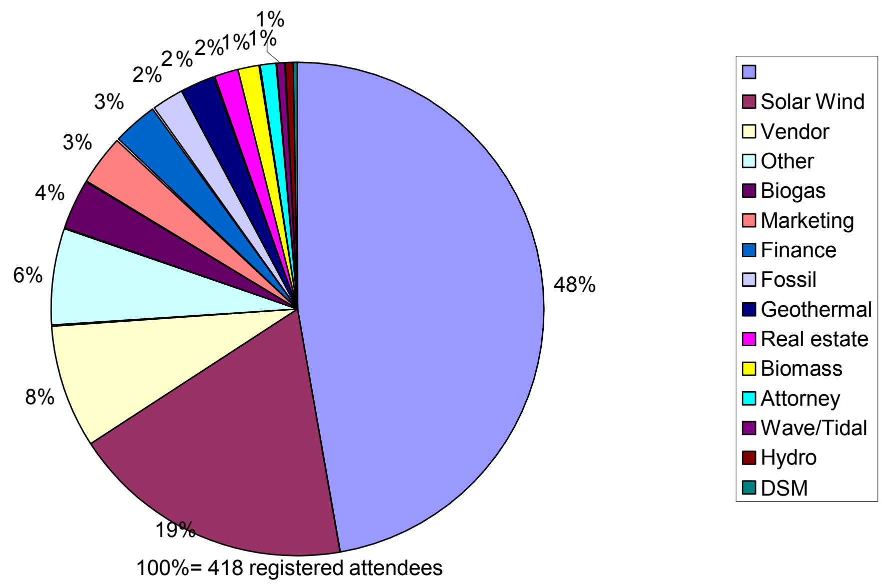
Arroyo notes that news of PG&E's RPS RFO was publicized not only in the trade press but also on the public websites of several law firms whose practices include a focus on renewable energy contract law, such as Allen Matkins, Davis Wright Tremaine, Stoel Rives, and Wilson Sonsini. The news of the RFO was also disseminated by the Geothermal Resources Council and the National Renewable Energy Laboratory.

Another indicator of the adequacy of outreach for the RFO was the response of attendees for the bidders' conference. Figure 2 counts individuals, by sector, who registered for the conference (there is no means to check who actually attended). A turnout of more than 400 individuals represents a very strong response and expression of industry interest, and is an increase of about 70% over the registration for the 2009 RPS RFO bidders' conference. The largest share of attendees represented the solar and wind sectors.

Arroyo estimates that out of the attendees at the 2011 bidders' conference, about 55% were with firms that submitted Offers. This was a higher portion than in the 2009 bidders' conference. This is an indication of successful outreach, in that the audience that registered for the conference was made up mostly of the staffs of developers, owners, or traders that were positioned to submit Offers, as opposed to vendors, attorneys, or consultants to developers, or to small entities that were not really prepared to propose projects.

Arroyo's conclusion is that PG&E conducted substantial outreach to renewable power developers in North America. The number of individuals contacted, the distribution of the news of the solicitation in the electric power trade press, and the strikingly large attendance at the bidders' conference and the decent yield of Offers submitted by conference attendees all suggest that PG&E's overall outreach effort was strong and effective.

Figure 2. Breakdown of registration for bidders' conference



C. ROBUSTNESS OF THE SOLICITATION

Here are some considerations used to evaluate whether PG&E performed successfully in conducting a robust solicitation:

- Was the response to the solicitation large enough for PG&E to expect to achieve its goal of procuring 1 – 2% of retail load, given the likely attrition of Offers between short list and commercial operation, without having to accept a majority of Offers?

- Was the response to the solicitation diverse with respect to technologies?

- Was the distribution of responses broadly represented by projects that were assessed as moderately or highly viable, or was there an excess of less viable Offers?

The Offers PG&E received totaled an immense volume of projected generation. If all the Offers were contracted they would total more than PG&E's entire retail load. Such a massive response to the RFO should provide plenty of opportunity for PG&E to negotiate, contract for, and procure the stated objective for the RFO of 1 to 2% of retail load. Total GWh/year volume elicited in Offers exceeded the 2009 RFO's response by more than 80%. This ratio of offered volume to targeted procurement volume reflects a remarkably healthy and robust response. More than 300 in-state projects were proposed for contracts, often with several variants (e.g. varying on-line dates, pricing packages, delivery terms, etc.).

The Offers submitted to the 2011 RPS RFO provided more technology diversity than those submitted to the 2009 RFO. There was a greater volume of 2011 proposals for projects using technologies or resources that were weakly represented in the last solicitation. While it is difficult to attribute this to specific outreach activities by the utility, Arroyo is aware that PG&E staff had actively reached out in order to make potential Participants using these weakly represented technologies aware of the availability of the RPS RFO as a means to obtain long-term PPAs. Given the large number of Offers submitted in 2011 using the well-represented technologies such as solar and wind, Arroyo does not believe that the outreach activities of the utility were in any way unfair to those developer communities.

D. ADEQUACY OF FEEDBACK FROM PARTICIPANTS

After receiving notification that their Offers had been rejected, several of the non-shortlisted Participants expressed an interest in follow-up discussions to be debriefed on reasons for the decision. Arroyo participated in many of these sessions. Based on the number of debriefing sessions that took place (about fifty) and the extent to which the utility team obtained actionable commentary about the RFO from Participants, Arroyo believes that PG&E sought adequate feedback about the bidding and evaluation process.

In general these feedback sessions were welcomed by Participants. They created an opportunity for Participants to obtain a somewhat clearer view of how PG&E's evaluation criteria and preferences applied to their specific Offers, and of what factors played a role in the failure to select the Offers. Many Participants, when prompted to offer feedback on PG&E's solicitation materials and process, had generally positive commentary, including positive ratings for the format of the Offer (such as for the verification checks built into the spreadsheet), for the process and its fairness, for the helpfulness of the bidders' conference, and for the opportunity to debrief on the outcome of PG&E's selection. A variety of specific criticisms were offered, including some constructive suggestions that are summarized later in this report. Some major themes of the criticisms included:

- Data requirements for the written Offers were onerous;
- More transparency in characterizing the price of short-listed Offers would be preferred (often by Participants whose Offers were not short-listed and who aspire to submit their projects to future solicitations with improved pricing);
- The requirement for hardcopies of the Offers should be dropped in favor of electronic-only submittals; and
- More clarity on how the Project Viability Calculator guidelines are applied would be helpful; many Participants disagreed with the Calculator's design because they felt their Offers were unfairly disadvantaged by how scoring criteria are specified.

Arroyo's opinion is that PG&E's efforts to give and receive feedback after the close of the solicitation were adequate and quite helpful both to the utility and to those Participants who were willing to take part in a debriefing session.

3. FAIRNESS OF OFFER EVALUATION AND SELECTION METHODOLOGY

The key finding of this chapter is that PG&E's evaluation and selection methodology for identifying a short list for the 2011 RPS RFO was designed fairly, overall. Arroyo has some disagreements with the utility's approach.

The following discussion identifies principles for evaluating the methodology, describes it, evaluates its strengths and weaknesses, and identifies some specific issues with the methodology and its inputs that Arroyo recommends be addressed in future solicitations.

A. PRINCIPLES FOR EVALUATING THE METHODOLOGY

The Energy Division of the CPUC has usefully suggested a set of principles for evaluating the process used by IOUs for selecting Offers in competitive renewable solicitations, within the template intended for use by IEs in reporting. These include:

- The IOU bid evaluation should be based only on information submitted in bid proposal documents.
- There should be no consideration of any information that might indicate whether the bidder is an affiliate.
- Procurement targets and objectives were clearly defined in the IOU's solicitation materials.
- The IOU's methodology should identify quantitative and qualitative criteria and describe how they will be used to rank bids. These criteria should be applied consistently to all bids.
- The LCBF methodology should evaluate bids in a technology-neutral manner.
- The LCBF methodology should allow for consistent evaluation and comparison of bids of different sizes, in-service dates, and contract length.

Some additional considerations appear relevant to PG&E's specific situation. Unlike some utilities, PG&E does not rely on weighted-average calculations of scores for evaluation criteria to arrive at a total aggregate score. Instead, the team ranks Offers by net market value, after which, "[u]sing the information and scores in each of the other evaluation criteria, PG&E will decide which Offers to include and which ones not to include on the Shortlist."[4] The application of judgment in bringing the non-valuation criteria to bear on

[4]Pacific Gas and Electric Company, "Renewables Portfolio Standard, 2011 Solicitation Protocol, May 11, 2011 (Updated June 7, 2011)", page 40.

decision-making, rather than a mechanical, quantitative means of doing so, implies an opportunity to test the fairness and consistency of the method using additional principles:

- The methodology should identify how non-valuation measures will be considered; non-valuation criteria used in selecting Offers should be transparent to Participants.
- The logic of how non-valuation criteria or preferences are used to reject higher-value Offers and select lower-value Offers should be applied consistently and without bias.
- The valuation methodology should be reasonably consistent with industry practices.

B. PG&E'S LEAST-COST BEST-FIT METHODOLOGY

The California legislation that mandated the RPS program required that the procurement process use criteria for selection of least-cost and best-fit renewable resources; in Decisions D.03-06-071 and D.04-07-029 the CPUC issued detailed guidelines for the IOUs to select LCBF renewable resources. PG&E adopted Offer selection and evaluation processes and criteria for its 2011 RPS RFO. These are summarized in Section XI of PG&E's 2011 Solicitation Protocol for its renewable solicitation, and detailed in its Attachment K.

Additionally, PG&E developed non-public documents for internal use that detail the protocols for each individual criterion used in the evaluation process. These include:

- Market valuation
- Portfolio fit
- Project viability
- RPS goals
- Adjustment for transmission cost adders
- Ownership eligibility
- Sites for development

The first five of these are listed as evaluation criteria in the 2011 RPS RFO solicitation protocol (in contrast to prior years, PG&E did not score Offers on Credit). Additionally, the protocol states two other criteria: the materiality and cost impact of Participants' proposed modifications to the RFO's requirements and to the PPA, and the total volume of offers submitted by a single counterparty (considering the volume of energy already under contract as well). In other words, PG&E stated that it will take into account the degree to which Participants have proposed changes to its 2011 RPS Form Agreement for contracting, and the degree of supplier concentration in contracts with individual counterparties.

This section summarizes PG&E's methodology briefly and at a high level; readers are referred to PG&E's 2011 RPS Solicitation Protocol and its Attachment K for a fuller treatment of the detailed methodology.

MARKET VALUATION

PG&E measures market value as benefits minus costs. Benefits include energy value and capacity value (Resource Adequacy); ancillary services value is assumed zero. Costs are PG&E's payments to the Participant, adjusted by Time-of-Delivery (TOD) factors as specified in the solicitation protocol. TOD factors serve as multipliers to the contract price per megawatt-hours (MWh) based on the time of day and season of the delivery, and are intended to reflect the relative value of the energy and capacity delivered in those time periods. Also, costs are adjusted to reflect transmission adders. The costs of integrating an intermittent resource into the electric system, such as load-following, providing imbalance services, operational reserves, and regulation, are assumed zero. Both benefits and costs are discounted from the entire contract period to 2011 dollars per MWh in the methodology.

PG&E measures energy value by projecting a forward energy curve (in hourly granularity) out to the time horizon of the contract period, and multiplying projected hourly energy price by the projected hourly generation specified by the Offer's generation profile. For dispatchable Offers, the protocol uses a real-option pricing model to measure energy benefit.

PG&E develops an outlook for the value of Resource Adequacy capacity as a time series of nominal dollar per kilowatt-year estimates. The CPUC established specific guidelines for estimating RA capacity.[5] Also, the CPUC decided to base Net Qualifying Capacity on a 70% exceedance level for solar and wind resources whose output is stochastic in nature, in a calculation that takes into account diversity benefits of multiple individual generators with different profiles. In 2011, the PG&E team has adapted its methodology for estimating the RA capacity of as-yet-unbuilt projects to match the CPUC guidance more closely. Capacity benefit is calculated as the product of capacity value and quantity, and discounted to 2011 nominal dollars.

PORTFOLIO FIT

For the 2011 renewable solicitation, PG&E employed a quantitative scoring system to assess the portfolio fit of an Offer into its overall set of energy resources and obligations. The team calculated one score for the firmness of delivery of the offered resource and another score for the time of delivery of the resource (relative to PG&E's portfolio needs). The overall score for portfolio fit is the numerical average of the two.

PROJECT VIABILITY

PG&E employed the Energy Division's final 2011 version of the Project Viability Calculator to assess the likelihood that a proposed generation facility will be completed and

[5] California Public Utilities Commission, Decision 09-06-028, "Decision Adopting Local Procurement Obligations for 2010 and Further Refining the Resource Adequacy Program", June 18, 2009.

enter full commercial operation by the proposed on-line date. The CPUC suggested that the Calculator is intended for use as a screening tool rather than a dispositive means of making selection decisions.[6] PG&E was also willing to use its business judgment in assessing the relative viability of projects rather than relying solely on Calculator scores to make selections.

The viability score is developed through an assessment of several attributes of the project provided in the detailed Offer, including

- Project development experience,
- Ownership and operating and maintenance experience,
- Technical feasibility,
- Resource quality,
- Manufacturing supply chain (e.g. constraints upon availability of key components),
- Site control,
- Permitting status,
- Project financing status,
- Interconnection progress,
- Transmission requirements, and
- Reasonableness of Commercial Operation Date (COD).

The Energy Division provided a set of scoring guidelines for each of these criteria, in a helpful effort to standardize how a project would be assigned a score between zero and ten for each. The guidelines support the pursuit of consistency and fairness in rating the viability of proposed projects room for judgment; the combination of the Calculator and its guidelines should serve as a guide to developers on how projects will be assessed by IOUs.

More discussion about the utility of the Calculator as a standardized tool as it was applied in PG&E's 2011 RPS RFO is provided below in the section about the administration of the methodology.

[6] California Public Utilities Commission, Decision 09-06-018, "Decision Conditionally Accepting 2009 Renewables Portfolio Standard Procurement Plans and Integrated Resource Plan Supplements", June 8, 2009, page 20. Arroyo agrees that it is imprudent to rely excessively on the numerical score to make a judgment about the likelihood a project will come on-line on schedule.

RPS GOALS

PG&E assesses the degree to which the Offer is consistent with and will contribute to the state of California's goals for the RPS Program, and the degree to which the Offer will contribute to PG&E's goals for supplier diversity. The CPUC has articulated specific attributes of renewable generation projects which can be considered in utility procurement evaluations, such as benefits to low-income or minority communities, environmental stewardship, and resource diversity, that do not clearly fall within the other evaluation criteria. Similarly, the CPUC has issued a Water Action Plan, and to the extent a renewable energy project makes use of water on site, its proposed use of water is evaluated for consistency or inconsistency with the CPUC's recommended water conservation practices.

Additionally, the state Legislature articulated benefits anticipated for the RPS program in the Legislative Findings and Declarations associated with the laws passed to create the program, and PG&E assesses the degree to which Offers would promote these benefits.

The Governor of California issued Executive Order S-06-06 that, among other things, established a goal that the state will meet 20% of its renewable energy needs with electricity generated from biomass. PG&E assesses the extent to which an Offer supports that goal.

PG&E has well-defined corporate objectives for supplier diversity, and evaluates whether the Participant is, or will make a good faith effort to subcontract with, Women-, Minority-, and Disabled Veteran-owned Business Enterprises (WMDVBEs). In the 2011 RPS RFO PG&E asked Participants to submit a completed Supplier Diversity Questionnaire with information on the Participant's WMDVBE status, its intent to subcontract with diverse entities, and its own supplier diversity program. The PG&E team scored these questionnaires as part of evaluating Offers against the overall RPS Goals criterion. A change in the 2011 RFO is that PG&E stated that it will include in resulting PPAs a contractual requirement to make good-faith efforts towards a contracted supplier diversity target, and to report annual payments to diverse subcontractors. In Attachment L it requested Participants to specify the percentage of subcontracting spending would be to WMDVBEs.

TRANSMISSION COST ADDERS

The cost of transmission to move power from a project offered in the solicitation to PG&E retail customers is considered in valuation. The methodology takes into account the need to upgrade the transmission network in order to accommodate the increment of new renewable generation in locations (clusters) that may require significant capital outlay, either by PG&E or by other IOUs. Each California IOU publishes a Transmission Ranking Cost Report (TRCR) which identifies clusters that require network upgrades to accommodate new generation, and estimates a proxy for the cost of upgrades and the amount of new generation that would trigger the need for upgrades. If a CAISO interconnection study has been completed, the team generally uses the more project-specific estimate of transmission network upgrade costs identified in the study rather than the TRCR-based proxy (assuming that the Participant has included the study as part of its Offer package, as was required).

PG&E takes into account both the cost of upgrades required to achieve a reliable interconnection as well as the cost required to achieve a fully deliverable interconnection, for Offers that propose to obtain a full capacity interconnection. While PG&E did not require

Participants to achieve full capacity interconnections in the RFO, Offers that proposed energy-only interconnections were not credited with any Resource Adequacy value.

The Solicitation Protocol and its Attachment K lay out the analysis required to allocate network upgrade costs to individual Offers. This includes the use of a model to calculate the present value of the impact of the network upgrade capital cost on revenue requirement, estimating in 2011 dollars per MWh the impact on customers of the upgrade.

This year, PG&E required Offers to specify a CAISO delivery point and a price at that point, rather than allowing them to propose delivery outside the CAISO. Alternatively, these Participants could propose to use a pseudo-tie arrangement or dynamic scheduling arrangement for the CAISO to manage delivery, despite a project's interconnection in a non-CAISO balancing authority area.

UTILITY OWNERSHIP ALTERNATIVES AND SITES FOR DEVELOPMENT

PG&E developed protocols for evaluating Offers proposing to sell the utility a site for development of renewable generation or to build a facility and transfer it to PG&E ownership. The evaluation of turnkey Offers includes an analysis of the project's value under PG&E ownership and a consideration of the extent to which ownership of such a project is compatible with the utility's core competencies.

There is little specific guidance about how PG&E evaluates the tradeoff between a PPA Offer variant and a Purchase and Sale Agreement (PSA) Offer variant (e.g. build and transfer to utility ownership) for the same project. Nor is there much guidance regarding how the utility evaluates compatibility of owning a project with PG&E's core competencies.

Similarly, both the public solicitation protocol and the non-public protocol give very little specific guidance about how PG&E evaluates Offers for sites for development, and Attachment K is silent on the subject. The protocol does not reveal what technologies PG&E would consider for such an Offer, what term is required, whether site sale or site lease is preferred, or any other requirements or preferences the utility applies when it evaluates proposed sites for development. In the actual event these Offers were evaluated based on criteria that were absent from both the public and non-public protocols, which Arroyo regards as less than fair to Participants. This lack of transparency detracts from the clarity of the RFO materials and contributed to wasted effort on the part of Participants.

COUNTERPARTY CONCENTRATION

In the 2011 RPS solicitation protocol, PG&E stated explicitly that it will consider its total exposure to volume of contracted deliveries from any individual counterparty and the volume already contracted with that party in making selection decisions. Arroyo regards supplier concentration as a legitimate business concern for the utility and its customers, both for credit risk for the utility's supply portfolio as well as risk of development failure.

This year, PG&E made an effort to avoid the prior practices of one or two individual developers that submitted excessively large numbers of Offers, by limiting the total number of Offers per Participant to five, with an exception for small Offers (up to ten Offers per Participant if the total capacity of Offers does not exceed 200 MW). Some developers still submitted more than five large Offers, and others circumvented the restriction by bringing in different part-owners for different groups of projects. Other developers submitted multiple Offers for projects owned by different subsidiaries or initially owned by other developers while retaining an option to purchase the project if successful. Overall, these tactics used to avoid PG&E's stated limitation do not appear to have benefited those developers at all, but it created excess effort for the utility team; PG&E chose to evaluate all Offers (absent a screening evaluation it would impossible to know which projects to reject).[7]

<u>PG&E'S PREFERENCES REGARDING OFFERS</u>

In addition to the various evaluation criteria, PG&E's solicitation protocol states two preferences regarding selection of Offers. In section III regarding Solicitation Goals, the section on contract term refers to regulatory uncertainty regarding implementation rules on annual compliance goals and states that "PG&E will encourage bids that recognize that uncertainty and offer flexibility toward meeting a range of possible targets (e.g., varied online dates)". Arroyo views this as a reasonable preference to take into account when making a short list given the status of PG&E's RPS compliance position for the next several years.

PG&E also states in its solicitation protocol a preference for projects that deliver power to "a nodal delivery point…within PG&E's service territory" over projects that deliver to CAISO interface points (e.g. the California-Oregon Border, Mead, Palo Verde, or Four Corners substations) or to "California locations outside of the CAISO's control area" (e.g. points within the grids of the Western Area Power Administration, or WAPA, Imperial Irrigation District, or IID, non-CAISO municipal utilities such as the Los Angeles Department of Water and Power, or LADWP, or non-CAISO rural electric cooperatives such as the Plumas-Sierra Rural Electric Cooperative), or to out-of-state locations.

Arroyo regards this as a reasonable preference, and appropriate to state in the protocol. Most of the operators of control areas external to the CAISO have in the past chosen not to provide imbalance service or operating reserves that would be required to enable an intermittent generator in their territory to schedule firm deliveries to a CAISO intertie. Also, contracting with projects that interconnect into PG&E's grid can have other benefits to the utility and its ratepayers, such as enhancing local voltage support. In situations where PG&E is cut off from other service territories (as for example the catastrophic collapse of SDG&E's and IID's systems in September 2011) the robustness of PG&E's system is enhanced by having renewable generation on line in its own territory rather than in other utilities' grids. Consequently Arroyo views PG&E's lower preference for out-of-state power or power delivered into non-CAISO control areas as based on legitimate business concerns.

A third area where PG&E's solicitation protocol does not quite express a preference or an evaluation criterion is in contract language modifications. The protocol states that the utility will assess the materiality and cost impact of the Participant's proposed modifications

[7] Some developers believed that the five-Offer limitation was too constraining in the situation where the company has a large "pipeline" of potential projects of multiple technologies. Other developers praised the five-Offer limitation, observing that "it was very intelligent to limit the size to five projects" because it avoided an even larger proposal response without affecting the short list, under the belief that the limit focuses developers' attention on their lowest-priced and most viable projects.

to PG&E's Form Agreement or standard term sheet. The inference is that the utility will generally prefer Offers where the Participant submits revisions and comments to the Form Agreement with modest or nil proposed changes to PG&E's standard terms and conditions over Offers whose mark-ups demand unfair concessions, such as projects that propose to post Delivery Term Security that is far less than PG&E's standard requirement.

While Arroyo views these preferences as legitimate business concerns and as factors that are reasonable for PG&E to consider in deciding which Offers to select or reject for its short list, Arroyo is concerned that the transparency of how such preferences affect Offer selection could be improved. In the debriefing sessions for non-shortlisted Participants it seemed that some were unaware of the expressed preference for projects interconnecting within PG&E's grid, or for projects interconnecting within the CAISO, vs. projects delivering at a CAISO intertie point. Arroyo recommends that in future solicitations PG&E edit the solicitation protocol to help clarify that preference.

Also, it would have improved the clarity of the solicitation protocol if it had explicitly stated that PG&E's preference would "focus on the latter part of the 2014-2016 compliance period" as stated in the bidders' conference presentation. It appears, based on debriefings after the RFO's close, that several Participants missed that point and assumed that Offers with earlier on-line dates were preferred, as had previously been the case in PG&E's 2009 RPS RFO. Arroyo speculates that some Participants could have improved the attractiveness of their Offers had they been aware of this subtly stated preference and acted upon it.

SELECTION OF A SHORT LIST

Having ranked Offers by market valuation, including the impact of transmission adders, and having scored the Offers against the non-valuation criteria, the PG&E team decides which Offers to include on the short list. As stated in the solicitation protocol, the team ranks all conforming offers based on net value, then uses scores and information from the non-valuation criteria to decide which Offers to include on the list, and which to exclude.

In conditionally accepting the 3 California IOUs' procurement plans for 2011 RPS solicitations, the CPUC noted that "each utility may apply its own reasonable business judgment in running its solicitation, within the parameters" and guidance provided by the CPUC. This affords PG&E a certain degree of latitude in making decisions about how to use information about criteria such as Project Viability and RPS Goals and preferences such as service territory and on-line date in selecting Offers. Unlike other utilities that employ a weighted average of scores for all criteria as a determinative measure to make selection and rejection decisions, PG&E can, up to a point, use its judgment to select lower-valued Offers or less-viable Offers that have special attributes in meeting RPS Goals, for example.

C. STRENGTHS AND WEAKNESSES OF PG&E'S METHODOLOGY

PG&E's evaluation methodology for renewable energy solicitations has been revised over the course of several years, and its evolution has benefitted from input from IEs, the utility's PRG, and internal review. It has thus achieved a certain degree of refinement that has strengthened the process from the perspective of fairness and reasonableness.

1. MARKET VALUATION

General strengths and weaknesses. PG&E's valuation methodology has several advantages over methods used by other utilities:

- It is rooted in a comparison to market price forwards rather than to model outputs for hypothetical future market price based on inputs such as forecast demand, modeled supply increases, and fuel price scenarios.

- It is relatively rapid to turn around several valuations at once, in contrast to the burdensome nature of running multiple cases of traditional utility production cost models with dozens of cases for each generating unit assumed built vs. assumed not built to calculate system cost differences between scenarios with each unit in vs. out.

- It uses a valuation concept that is generally accepted in the electric power industry.

- It provides an intuitive valuation based on the degree to which a generating unit is "in the money" with respect to market price

There are some drawbacks with this approach, some of which are common to any valuation methodology for long-term PPAs:

- Because western power forward markets are not liquid and transparent beyond a limited time horizon, PPAs that last for up to 25 years must rely on extrapolation of market forward curves for valuation rather than on direct observation of traded prices for power two decades hence.

- A certain degree of interpolation or projection is required to achieve hourly granularity in price assumptions.

- In the absence of functioning, liquid, transparent markets in California for Resource Adequacy, the valuation must rely on fundamental forecasts for the value of capacity rather than on traded forward curves.

- There are challenges in estimating what Net Qualifying Capacity will be assigned by the CAISO to a project that does not yet exist. To a large extent PG&E must rely on the generation profiles provided by Participants, some of which appear to be of dubious quality.

- The methodology, given its inputs from forward curves, RA value assumptions, and discount rate, sometimes gives results that might appear counterintuitive, such as preferring higher-priced but longer-term contracts to lower-priced but shorter-term contracts, or preferring PPAs with later on-line dates to earlier on-line dates, all else being equal. Such outcomes can be explained by inspection of the data and input parameters and are consistent with the methodology. If the results run counter to the utility's or ratepayer's preferences, issues can be addressed through PG&E's flexibility to apply business judgment to its decisions.

- In the 2011 RPS solicitation, PG&E has used historical information about locational marginal price (LMP) to adjust the valuation of Offers based on the historical record. Attachment K to the solicitation protocol displayed the aggregation multipliers used to adjust for LMPs in various zones within the CAISO. Unfortunately, analogous multipliers had not been prepared for delivery points at intertie points of the CAISO; Arroyo recommends that prior to the next RFO the PG&E team investigate how best to make LMP adjustments for Offers that propose to deliver at such points.

Price vs. Value. PG&E's LCBF methodology takes into account both proposed price and estimated net value of each Offer, in the sense that price is a key input to the utility's valuation model. However, PG&E ranks Offers and Offer variants by calculated net value to make a primary screening for selection purposes, and does not construct or review a separate ranking by contract price. The valuation ranking takes into account the total cost to ratepayers of a PPA by including the contract payments (or purchase price) for a project and the transmission rate impact of required network upgrades and the effect of differing market prices across zones on the attractiveness of a project's output. When reviewing Offers to make a short list, PG&E does include information on LCBF-based net value and pricing, but the focus is on net value including transmission cost impacts rather than on contract price.

Financial Benefits and Costs. Overall, PG&E's LCBF methodology adequately takes into account nearly all financial benefits and costs of proposed Offers (see below for one exception). There are some areas that would be challenging for the evaluation team to quantify in financial terms. For example:

- Environmental externalities relating to the impact of new projects on wildlife or scarce water supplies are difficult to quantify as financial costs. A sub-team of PG&E's evaluation team reviews such aspects of proposed projects as their potential impact on threatened and endangered species. While these concerns are not translated into estimates of financial costs, PG&E's selection of a short list is informed by these data.

- Some local areas of PG&E's grid could suffer from deficiencies in local capacity resources compared to requirements identified to maintain local reliability. For example, the CAISO has identified a deficiency of 36 MW of resources in the Sierra local area within PG&E's territory.[8] It is difficult to quantify as financial benefits the extra benefit to grid reliability that would be provided by contracting with new resources in local areas with deficiencies.

- The California IOUs assume that the cost of integrating new resources into the electric system is zero, consistent with current CPUC policy. Utilities in other jurisdictions apply estimated costs of integration for intermittent resources when ranking the value of potential new projects, based on estimates of such components as obtaining sufficient load-following resources and voltage/frequency regulation. One might anticipate that at some point as load

[8] California Independent System Operator, "2012 Local Capacity Technical Analysis: Final Report and Study Results", April 29, 2011, page 2.

grows and as intermittent resources make up a greater proportion of the resource mix within the CAISO the price of increasingly scarce but required load-following and regulation may increase. This potential effect is not included in PG&E's valuation; there is no CEC-approved methodology for such an estimate.

Arroyo acknowledges the challenges of quantifying benefits and costs such as these in monetary terms, and opines that the PG&E LCBF methodology incorporates most financial benefits and costs that reasonably can be estimated at this point in time, with the following two exceptions.

<u>Transmission upgrade costs.</u> As described above, PG&E's LCBF methodology includes the costs of transmission upgrades in its value calculations of all Offers involving projects that propose to interconnect directly to the CAISO, using proxy costs from TRCRs or estimates of network upgrade costs from interconnection studies or executed interconnection agreements. However, the methodology does not take into account these costs in situations where the project proposes to interconnect outside the CAISO balancing authority area and the network costs are ultimately borne by transmission customers of that other balancing authority area. Arroyo believes that valuing projects in these areas without applying transmission adders while valuing projects within the CAISO with adders is less than fully fair to developers of projects within the territories of the three IOUs.

Arroyo recommends that PG&E incorporate estimates of transmission upgrade costs for Offers where projects propose to interconnect within California to non-CAISO balancing authority areas that are entirely or partially located within California. While Arroyo acknowledges that PG&E's ratepayers will not directly bear the costs of network upgrades in these other BAAs, the California ratepayers served directly by these balancing authorities will. Additionally, to the extent that PG&E procures energy from projects within such BAAs, taking delivery at a CAISO intertie point, PG&E's customers will pay a contract price for that power which recovers the cost of transmitting the project's output to the intertie, and those transmission tariffs will eventually reflect the cost of required network upgrades. However, in the 2011 RFO, Arroyo can identify at most one proposal whose selection or rejection might have differed if non-CAISO network upgrade costs had been counted.

<u>Congestion charges.</u> As described previously, the current implementation of the LCBF methodology does not count the congestion charges between certain distant CAISO delivery points and the EZ hubs internal to CAISO service territories. Arroyo recommends that the PG&E team develop estimates of LMP multipliers appropriate for these delivery points as it has done for zones within the main body of the CAISO grid.

<u>2. EVALUATION OF PORTFOLIO FIT</u>

The approach PG&E employed in the 2011 RPS RFO to score Offers on portfolio fit differed from that used in prior years. The current approach has specific advantages:

- The numerical score is based on quantitative calculations or on technology-specific attributes, and is objective in its development with little discretion or judgment involved in applying scoring guidelines.

- The scoring for time of delivery is closely related to how PG&E currently perceives its greatest needs for new RPS procurement, an important consideration for compliance strategy.

There are a few drawbacks to this approach:

- The current scoring approach is somewhat black and white; it tends to provide either a high score or a low score with few steps in between.

- In the greater scheme of things, the portfolio fit criterion does not appear to have as much impact as others such as market valuation, project viability, and RPS goals. To Arroyo's awareness there has not yet been a situation where a renewable Offer's superior portfolio fit score has enabled it to be shortlisted by PG&E despite inferior value or viability; nor has there been a situation where an inferior portfolio fit score has led an Offer to be rejected from a short list.

PG&E's revised portfolio fit criterion for the 2011 RPS solicitation is consistent with the utility's current understanding of its generation need for each compliance period under SBX 2. Arroyo has almost no visibility into how PG&E calculates its net short position of RPS-eligible energy procurement vs. RPS goals in the three compliance periods and can therefore have no opinion about whether that calculation was reasonable. To the extent information was made available to the utility's Procurement Review Group, it appears that the portfolio fit methodology aligns well with times when PG&E expects more procurement is needed.

The utility's estimates have considerable potential for error, both because of uncertainty about how the CPUC's implementation rules will set targets for intermediate years like 2014 and 2015, and because of uncertainty about the likelihood that contracted projects will come on-line and the extent to which projects whose PPAs are expiring will be recontracted.

<u>3. EVALUATION OF BIDS WITH VARYING SIZES, IN-SERVICE DATES, AND CONTRACT LENGTH</u>

<u>Offer Size.</u> PG&E's LCBF valuation methodology is essentially neutral to project size; it does not consider extrinsic variables such as MW capacity or GWh volume as positive or negative factors but rather reduces the value of the Offer to a normalized $/MWh metric. To the extent project size has an impact on valuation, it reveals itself in the proposed contract price if the technology is one that provides economies of scale and enables developers to propose lower prices for larger projects.

The viability scoring system, however, is not neutral to project size. The larger the proposed project, the less likely it is that the developer has succeeded in the past in developing similar or larger sized projects, owned and operated similar or larger sized projects, or financed similar or larger sized projects. So the Offer is likelier to score lower on Project Development Experience, Ownership/O&M Experience, and Project Financing Status if the project is larger.

From the debriefings after the conclusion of the RFO, it became evident that many developers failed to appreciate that proposing new projects much larger than any they had previously brought into operation will lower their viability score using the Energy Division's Project Viability Calculator. Other developers with deep experience in developing large projects in conventional technologies were unaware that the design of the Calculator did not fully take that experience into account in scoring when they proposed to construct large projects using a renewable technology with which they had no prior experience.

This left some non-selected Participants with a sense that the design of the Project Viability Calculator was unfair to them, arguing that it has a "rich get richer" aspect in which only those developers who have previously brought into operation large renewable energy projects can achieve the highest scores for developer and ownership experience for proposed new large renewable energy projects.

The fact that PG&E's objective for the 2011 solicitation is to procure 1 to 2% of retail load, combined with the RFO Goals non-quantitative factor of resource diversity, makes it difficult for the utility to select the very largest-volume proposals offered. An extreme hypothetical scenario in which the utility selects one Offer only of several TWh/year would be the opposite of pursuing resource diversity. The RFO Goals criterion gives PG&E the basis for preferring to select multiple smaller Offers rather than a very few large projects, in pursuit of greater resource diversity. This tradeoff between the criteria of highest valuation vs. resource diversity requires the utility to exercise business judgment about its priorities.

<u>On-Line Date.</u> PG&E's LCBF valuation methodology, using current inputs, exhibits a propensity to favor projects that start later rather than earlier, all else being equal (this is related to inputs about forward prices, capacity value, and discount rate). It is a modest effect, and is roughly consistent with the stated preference of the utility to focus on the latter part of the 2014-2016 compliance period rather than on the first compliance period.

Because of the focus of PG&E's methodology on selecting projects ranked high for net value and project viability, the process is not designed to provide a short list that fits best with PG&E's net short position for RPS compliance. That would require the most valued and most viable proposals to have offered in-service dates that closely match the compliance periods when the utility has the largest net short position, which would be coincidental if it occurred. Instead, because there are more than three evaluation criteria to pursue, the methodology is designed to construct a short list composed primarily of high-valued and highly viable proposals of which some have on-line dates that fall close to compliance periods with short positions, but of which others have substantially earlier or far later in-service dates and don't necessarily fit well with compliance periods of the greatest need.

Similarly, PG&E's methodology is not designed to construct a short list with the highest value to ratepayers while meeting the utility's RPS compliance needs. Such an alternative approach would necessarily disregard the project viability criterion by selecting the highest valued Offers with in-service dates matching RPS compliance periods of greatest need, regardless of whether those low-priced and well-timed projects have progressed at all in permitting, interconnection, and site control processes, and whether or not their technology is well-commercialized or never before demonstrated at utility scale. The IOUs have had bitter experience with low-priced projects that proposed attractive on-line dates but failed to achieve timely commercial operation because of viability issues. PG&E's methodology is designed to screen out high-valued projects that fit well with compliance period needs if they rank low on project viability. If the PG&E had an alternative approach that disregards viability in pursuit of highest value and fit with compliance needs, then one would expect a short list with a significantly higher likelihood of contract failure than the current approach.

Contract Duration. The valuation methodology similarly tends to favor contracts with longer duration to those with shorter terms, all else being equal. Since few Participants ever seem to propose both a longer and shorter duration contract at the same contract price, this is a very minor effect, typically swamped by price differences between Offer variants.

4. EVALUATION OF BIDS' TRANSMISSION COSTS

The valuation methodology assigns estimated transmission costs to the contract price of generation in order to compare Offers fairly, taking into account the full cost of generating power including upgrades required to achieve reliable deliverability for new generation. Many features of the transmission cost methodology are specified by regulatory decisions.

The methodology has a few strengths:

- It provides a means to level the playing field between Offers that deliver directly into PG&E's service territory at uncongested locations and those whose proposed facilities will require expensive new transmission upgrades and new substation facilities to maintain grid reliability.
- It provides a view of full costs of the project rather than only the energy procurement cost.

The transmission cost methodology also has some drawbacks:

- The process of estimating transmission adders is analytically burdensome. It requires checking of Participant's information by transmission experts and consumes a considerable portion of the total time for valuation analysis.
- TRCR adders are a generalized, regional proxy for the actual cost of a particular-sized project at a particular interconnection point. There can be rather large deviations between the final cost of network upgrades written into an interconnection agreement and an early TRCR estimate.
- In those cases where the TRCR adder turns out to be an underestimate of actual network upgrade cost, PG&E's prior practice of only performing the full LCBF valuation including transmission adders during solicitations impedes the transparency of decision-making.
- TRCR adders are available only for California IOUs, and only for specific transmission clusters that the IOUs have analyzed. They are not available for other balancing authorities in California or outside the state. It would be challenging for the PG&E team to estimate a proxy for network upgrade cost for projects interconnecting, for example, in the Sacramento Municipal Utility District's or IID's grid unless the project had obtained a system impact study or facilities study or

interconnection agreement from that balancing area authority. Given the focus on new renewables in Imperial Valley, this shortage of information is inconvenient.

- CAISO Phase I studies have been known to provide gross early overestimates of the actual network upgrade costs. In some transmission clusters, excessive numbers of new projects have applied for interconnections; their aggregate new capacity is so large that Phase I estimates of work required to accommodate such a large new build are massive. When posed with the obligation to finance hundreds of millions of dollars of network upgrades for their projects, many developers choose to drop out of the CAISO queue, leaving sufficiently fewer new projects moving through the Phase II study to result in much smaller estimates of network upgrade costs. In these situations, the methodology disadvantages projects that have received a Phase I study but not yet a Phase II study, even though the analysis in hand is the best currently available estimate of project-specific upgrade requirements. This seems less than fully fair to some projects caught in that early stage of analysis.

Whether the transmission adder methodology relies more on TRCR proxy adders or on interconnection studies or interconnection agreement data depends entirely on what projects Participants submit. In the case of PG&E's 2011 RPS solicitation, roughly half the Offers had not applied for an interconnection or had not yet completed a Phase I study or system impact study. This illustrates how reliant the methodology is on the accuracy of the IOUs' Transmission Ranking Cost Reports.

Most Phase I and Phase II interconnection studies provide estimates of both reliability network upgrades and deliverability network upgrades. In situations in which the project has not yet been studied as a full capacity resource, the studies lack an analysis of required deliverability upgrades. In many cases projects apply for an energy-only resource and later request a deliverability assessment (such as for projects that initiated their application under the Small Generator Interconnection Process). PG&E's methodology is designed to be internally consistent; either it treats a project as energy-only and takes into account the estimated reliability network upgrades only and doesn't attribute Resource Adequacy value to the facility, or it treats it as full-capacity, takes into account costs of both reliability and deliverability network upgrades, and attributes RA value. In some cases projects were analyzed both ways and the approach that provided the higher valuation was selected, giving the project the benefit of the doubt that of the two the higher-valued approach would be chosen. This would be consistent with the logic of PG&E choosing to contract with a new project as an energy-only resource if the deliverability network upgrade costs would exceed the value of Resource Adequacy the project can provide.

Conformance checks of transmission study results were performed. Arroyo notes that some Offers misstated the estimated network upgrade costs provided by CAISO or PTO studies. Arroyo believes that PG&E did a thorough job of checking the original source materials when conducting its analysis of transmission adders. Part of the challenge was that many Participants omitted the requested copy of the latest interconnection study, requiring the utility team to seek this information for deficient Offer packages.

<u>5. EVALUATION OF BIDS' PROJECT VIABILITY</u>

The implementation of the Project Viability Calculator as a screening tool for use in the evaluation of Offers has brought several advantages:

- The Calculator is a step in the direction of more standardized evaluation of viability across all three IOUs.
- The Calculator provides a broader set of criteria by which projects are assessed than was the case with PG&E's prior approach to scoring viability.
- The range of scores from zero to 100 gives more visibility to differences between projects than methods that use single-digit scores.
- The methodology allows PG&E to use both the more standardized tool as well as business judgment in taking project characteristics into account when making short list decisions.

There are still opportunities to improve the use of the Calculator.

- Some of the scoring guidelines for the Calculator are sufficiently ambiguous that reasonable individuals scoring the same project can arrive at different results. When the scores rated by Arroyo and the PG&E team were compared, the variance between scores had a standard deviation of 12 points. Even among individual members of the PG&E team there was a need to review and standardize scoring to reduce discrepancies between individuals' practices. This suggests that the Calculator is still a crude screening tool with a lot of noise in the scoring process, and that differences of only two or three points between projects should not be regarded as determinative in selecting one and rejecting the other, because the difference falls within the error of the analysis.
- As evidenced by feedback from Participants, developers in general have a poor understanding of how the utility interprets the scoring guidelines. Many developers, for example, claimed not understand that their project cannot obtain a score of 10 out of 10 for project development experience if their team has never brought at least two projects of equal or larger size with similar technology into operation…even though that is explicitly what the scoring guidelines in the Calculator state.
- Some scoring criteria would be difficult for a layperson to interpret, such as the Transmission System Upgrade Requirements criterion that requires some basic knowledge of what components of an upgrade require or don't require a CPUC Permit to Construct of Notice of Construction. Many or most developers lack on-staff experts in the regulatory landscape for new transmission build in California.
- Some of the Offers were scored low simply because the Participants omitted basic information about their projects, even though upon debriefing it became clear that full disclosure would have resulted in a higher viability score. It is unclear to Arroyo how this could be improved in the future, since the solicitation materials clearly stated what information was required.

In Arroyo's opinion, PG&E reasonably measured the viability of every project that submitted a conforming proposal for bundled energy, out-of-state power attached to renewable energy credits, or biogas. The evaluation team did not use the Calculator to evaluate Offers for RECs only or sites for development; some Participants for the former did not submit data needed to evaluate their viability, and proposals of land sales or leases are not amenable for scoring as power projects with the information requested or supplied.

The Participants' self-scoring was uneven in quality. While the PG&E team agreed with the self-scored Calculator scores for about a quarter of Offers, on average PG&E gave the Participant-estimated scores a "haircut" of eleven points. This is somewhat distorted by a few developers who scored their own projects by more than 40 points higher than the PG&E team; Arroyo agreed with PG&E that these projects had been assigned grossly inflated scores by any objective standard.

PG&E conducted conformance checks of viability assessments for Offers, in part to ensure quality control and consistency in how multiple scorers applied the scoring guidelines. Particular attention was paid to Offers that were considered for short listing in early drafts, in order to confirm the quality and consistency of the assessments.

In some cases factors not assessed by the Calculator were taken into consideration when the PG&E team made selections; this is consistent with the direction provided by the CPUC about the use of the Calculator as a screening tool.

6. OTHER STRENGTHS AND WEAKNESSES

Evaluation of different technologies. PG&E's protocol tends to avert selecting Offers for utility ownership for which the utility lacks particular core competencies, so there is a bias against purchasing projects that the company is less well-suited to own and operate. This seems reasonable and appropriate, since it is not in ratepayers' interest for the utility to own generating facilities that require specific skills PG&E lacks.

The Project Viability Calculator was designed to be technology-neutral as well. However, the Calculator will return a lower score for a project that relies on a technology that is not well-commercialized, or that the developer lacks prior experience developing, owning, operating, or financing, all else being equal. The methodology will tend to discount projects based on emerging technologies or on those that have not been implemented broadly at utility scale, and will tend to promote projects that rely on technologies with widespread market acceptance and many examples of operating 100+ MW installations. It became evident from debriefing Participants that some developers were unaware that the Calculator's design tends to disfavor emerging technologies, and that other competitive venues than the IOUs' RPS RFOs that do not require the use of the Calculator might be more appropriate for projects that employ poorly-commercialized technologies.

PG&E's protocol for RFO Goals includes a provision allowing the utility to consider the non-quantitative factor of resource diversity benefits in the selection process; this is stated in Attachment K and supported by regulatory decisions. This feature allows the utility to consider such things as its resource need for baseload vs. peaking or intermittent generation in selecting Offers. To the extent some technologies are operated as baseload in the

California market and there is a resource need for baseload resources this may tilt Offer selection towards those projects over technologies that provide intermittent or peaking generation. Similarly, the RFO Goals criterion accommodates the non-quantitative factor of continuing to meet the goal stated by Executive Order S-06-06 for biomass-fueled renewable energy, which could tilt Offer selection towards biomass or biogas-fueled generation.

Out-of-state projects. One issue regarding both value and viability concerns Offers for out-of-state projects that propose not to actually deliver power to the CAISO but instead intend to be managed through a pseudo-tie or dynamic scheduling. There are only a very few projects to date where these have been implemented by the CAISO. Because such approaches require the assent of both the CAISO and the foreign balancing area authority to which the project will interconnect (and PTOs in between), it is difficult for PG&E to judge the likelihood of whether such arrangements will actually be achieved. It was evident from reviewing out-of-state Offers that several Participants do not comprehend how their projects will be treated by the CPUC for RPS compliance purposes, with several assuming that their PPAs will be treated as bundled in-state delivery of power, despite failing to specify how they will obtain dynamic scheduling by the CAISO. One hopes that more experience with dynamic scheduling will make it clearer what can and cannot be achieved with these arrangements and that future solicitation protocols can clarify how PG&E will assess them.

Similarly, Arroyo considers it risky for the utility to value out-of-state projects that assume that the import of their power at a CAISO intertie will provide full Resource Adequacy value to PG&E ratepayers. The process for allocation of RA import capability at intertie points does not currently accommodate long-term dedication of that capability to IOUs, putting at risk the delivery of RA value. Simply assuming that full RA benefits of the capacity of these out-of-state projects will be realized for the entire delivery term of a PPA may overstate the value of these projects. However, in the actual selection of projects Arroyo can identify at most one Offer whose selection or rejection might have differed if PG&E had taken a different approach in evaluating pseudo-ties or RA import capability.

Participants' viewpoints on strengths and weaknesses. Feedback from Participants provided some insight into other strengths of PG&E's approach compared to other utilities'.

- The bidders' conference was cited as being "very helpful" by several Participants, in clarifying objectives, evaluation process, and requirements. The ability to ask questions and to obtain answers quickly and spontaneously was cited as useful.

- The solicitation materials were regarded as clear, straightforward, and "user-friendly", with the exception of the Attachment D offer form, with which some Participants had technical difficulties. (Others found the verification process built into this year's Attachment D to be quite helpful and fully functional.) Participants who submitted less commonly pursued approaches (e.g. projects outside the CAISO or sites for development) tended to be more frustrated with their perception that the solicitation materials lacked clarity about their Offers would be evaluated.

- While some Participants clearly did not understand how the scoring guidelines in the Project Viability Calculator were intended to be used and were frustrated that their early-stage projects were disfavored by the design of the Calculator, others expressed opinions that the Calculator was "fair and relevant" and straightforward.

- While frustrated by PG&E's policy of not disclosing detailed information about the nature of the short list, and the utility's unwillingness to provide second chances to improve rejected Offers, Participants appreciated the opportunity to be debriefed about the reasons why their Offers were rejected because they could gather useful information on how to make their projects more competitive in future solicitations. Some Participants particularly appreciated that PG&E provided timely responses about whether their Offers were selected or rejected, in contrast to another IOU.

- Some Participants felt disadvantaged compared to rivals who, they feared, could propose unreasonably low pricing, obtain a PPA, then sell the project. They suggested that PG&E erect higher barriers to participation by "non-serious" parties, such as higher offer deposits (as required in other jurisdictions). Arroyo views this theme as a form of confirmation that PG&E's approach to outreach was successful in obtaining broad and robust competition from the developer community.

D. FUTURE LCBF METHODOLOGY IMPROVEMENTS

The methodology employed by PG&E has undergone repeated refinement, motivated both by internal choices within the utility and external impetus by the regulator. This process has provided incremental improvements to the methodology over time. Arroyo can at this point only suggest a few modest changes that may further improve the means by which PG&E evaluates Offers or the transparency with which Participants can view the evaluation process, some of which were suggested in feedback sessions by Participants.

ENHANCING TRANSPARENCY

One set of suggestions would seek to address the sense that comprehension of how PG&E evaluates and selects Offers among the developer community could be improved. This could help reduce wasted effort on the part of developers in promoting projects that are unlikely to be selected, and reduce the amount of wasted effort within the utility as it attempts to analyze Offers with poor viability and low value. Some ideas could include:

- Reviewing the scoring guidelines for the Project Viability Calculator in the bidders' conference, to explain what is required to obtain top scores in each criterion;

- Including scoring guidelines for all 11 criteria used in the Calculator in Attachment K, with commentary on what it takes to obtain top scores in each category;

- Editing the solicitation materials to further emphasize the need for out-of-state projects to provide a full price at a CAISO delivery point that the developer would be willing to write into a PPA, rather than a busbar price outside the CAISO;

- Modifying solicitation materials to clarify that the developer must provide a copy of the most recent interconnection study or executed interconnection agreement that will serve as the basis for estimating a transmission adder for network upgrades;

- Revising the solicitation materials to clarify that, in addition to the various evaluation criteria, PG&E will use its preferences regarding delivery point and commercial operation date to make selection decisions. In particular, it would be key to make as clear as possible within the solicitation protocol itself what PG&E's preferences for on-line date are, seeing that many Participants completely failed to notice this;

- Editing the both the public and non-public solicitation protocols to provide a fuller description of how Offers for sites for development will be evaluated, what the basic requirements for eligibility are, what specific evaluation criteria will be used, and what characteristics of offered sites would render them attractive or unattractive to the utility as candidates for ownership. The ownership team should provide clearer internal documentation of how it made its selection and rejection decisions.

STREAMLINING THE PROCESS

At least one other IOU has chosen to drop the requirement for hardcopies of the Offer package; to Arroyo this now seems an appropriate step for PG&E to take, going forward. Arroyo has some lingering concern about the Participants who fail to put all the information present in their hardcopy Offers into readable electronic form using the required format, but this may be dispelled if Offers are submitted entirely in electronic form. Arroyo agrees that it is still best to submit electronic Offer packages by flash drive rather than by e-mail.

Some Participants have objected to the volume of information that PG&E requires for a complete Offer. Arroyo agrees that there are some opportunities to delete some required information that has little or no impact on a short-listing decision (such as project block diagrams and resumes of managers) in favor of seeking such information after short-listing.

IMPROVING VALUATION INPUTS

Arroyo has suggestions for improving the methodology for assessing the value of Offers:

- Use a discount rate based on an estimate of the cost of capital for power developers, rather than PG&E's authorized cost of capital. Arroyo believes that given the risks that face renewable project development (permitting, site control, interconnection, equipment procurement, financing, etc.) it is more appropriate to discount future benefits and costs of the projects using a higher discount rate representative of the riskier independent power industry, rather than that of a regulated monopoly.

- Restudy the inputs to the model that set the basis for Resource Adequacy valuation. For example, it appears that PG&E's current assumption for new entrant capital costs is materially higher than that embedded in the currently applicable Market Price Referent. Arroyo believes that current assumptions (including the use of a regulated utility's cost of capital as discount rate) cause the PG&E team to overstate the value of RA capacity, and that this tends to create distortions and biases in project valuation rankings.

- Clarify that the most recent CAISO or PTO interconnection study (or interconnection agreement if available) is required in the Offer package. Without this non-public information it is difficult to assess an appropriate transmission adder other than using TRCR information, and data from either a Phase I or Phase II study report is more specific to a given resource than TRCR proxy estimates.

- Develop LMP multipliers for CAISO interconnection points at the periphery of the balancing authority area, such as Four Corners, Moenkopi, Mead, and the Hassayampa-North Gila line, so that energy from projects that propose such nodes as delivery points can be valued taking congestion into account. These are CAISO delivery points that are external to the body of the IOUs' service territories and tend to record higher congestion differentials than points within the territories.

- Discuss with the CAISO its plans and policies for establishing pseudo-ties or dynamic scheduling arrangements for new projects outside the balancing authority area, in order to establish a view about which projects realistically can expect to obtain such treatment and which not. For example, Arroyo perceives it as unlikely that the CAISO could or would set up dynamic scheduling arrangements with projects that interconnect in WECC balancing authority areas that would require wheeling through three service territories to get to a CAISO intertie.

- Offers claiming that a project will be managed as a pseudo-tie should be required to state the specific CAISO intertie with which it will be permanently associated as required by CAISO rules; this would clarify how best to value the proposal.

- Include in the LCBF valuation the costs of network upgrades for projects that interconnect within California but outside the CAISO grid. The practice of evaluating full costs for some projects but PPA costs only (omitting the impact on transmission rates) for other California projects seems inconsistent and less than fully fair to developers who choose to build their generation within the CAISO grid. It also seems less than fully fair to California customers in non-CAISO balancing authority areas who will bear the primary burden for those upgrades.

4. FAIRNESS OF HOW PG&E ADMINISTERED THE OFFER EVALUATION AND SELECTION PROCESS

This section describes the extent to which PG&E's administration of its protocols for Offer evaluation and selection in the 2011 RPS solicitation was conducted fairly. Arroyo's overall conclusion is that the process was conducted in a fair and generally consistent manner. Arroyo disagreed with PG&E about the length of its short list. This chapter discusses how PG&E developed a final short list to submit to the CPUC.

A. PRINCIPLES USED TO DETERMINE FAIRNESS OF PROCESS

The Energy Division has suggested a set of principles proposed to guide IEs in determining if an IOU's administration of its evaluation and selection process was fair:

- Were all bids treated the same regardless of the identity of the bidder?
- Were bidder questions answered fairly and consistently and the answers made available to all bidders?
- Did the utility ask for "clarifications" that provided one bidder an advantage over others?
- Was the economic evaluation of the bids fair and consistent?
- Was there a reasonable justification for any fixed parameters that were a part of the IOU's LCBF methodology (e.g., RMR values; debt equivalence parameters)?
- What qualitative and quantitative factors were used to evaluate bids?

Some other considerations appear relevant to reviewing PG&E's administration of its methodology. The use of business judgment in bringing multiple non-valuation criteria to bear on decision-making, rather than a mathematical, objective means of doing so, implies an opportunity to test the fairness of administration using additional principles:

- Were the decisions to reject higher-valued Offers from the short list because of low scores in criteria other than valuation or PG&E's preferences applied consistently across all Offers?
- If PG&E did not select the projects for the short list that provide the best overall value while meeting the needs of PG&E's three compliance periods, what factors prevented those projects from being selected? Was their rejection based on factors that were communicated transparently to Participants in the solicitation protocol?

- Does the resulting short list conform to the needs of PG&E's portfolio?

- Were the judgments used to create the short list based on evaluation criteria and preferences that were publicly made available in the solicitation protocol to Participants prior to Offer submittal?

B. REVIEWING PG&E'S ADMINISTRATION OF ITS EVALUATION AND SELECTION PROCESS

PG&E provided Arroyo Seco Consulting with many detailed inputs to its valuation model and with results of market valuation at several steps during the evaluation process, including detailed information about transmission adders applied to Offers. Arroyo also had copies of all Offers and of correspondence between PG&E and Participants during this period, and was able to make independent opinions about the strengths and weakness of individual Offers against the evaluation criteria laid out in PG&E's protocols.

Arroyo was present at evaluation team and steering committee meetings in which draft proposals for the short list of Offers were developed, reviewed, questioned, modified, argued, and finalized. The logic and priorities underlying why specific Offers were rejected and accepted to the short list were made evident in these sessions. Arroyo had access to members of the evaluation team responsible for scoring the Offers against each of the evaluation criteria. Arroyo was able to question decisions that appeared unfair or inconsistent from an independent perspective.

Additional elements of Arroyo's approach for evaluating the fairness of the evaluation and selection process include:

- Building an independent valuation model that directly used detailed Offer information, to construct an independent ranking of Offers by net market value;

- Independently scoring Offers using the 2011 Project Viability Calculator;

- Developing a separate and independent point of view about which Offers most merited selection for a short list;

- Comparing PG&E's valuation ranking to the IE model's ranking, identifying outliers (e.g. where the utility ranked an Offer much higher than the IE or vice versa), identifying the root cause for variances, and determining whether variances were justified by different inputs and methodology or stemmed from errors by either PG&E or Arroyo;

- Auditing communications between PG&E and Participants to check whether any individual Participant was advantaged by requests posed or information provided;

- Reviewing in detail and discussing PG&E's decisions to reject Offers for nonconformance with the requirements of the solicitation protocol;

- Reviewing PG&E's decisions to reject Offers for low scores in non-valuation criteria, or based on the utility's stated preferences, and independently reviewing whether those rejections were fair and reasonable;

- Testing these rejection and acceptance decisions for consistency; reviewing whether the logic for rejection and acceptance was consistently applied to all Offers.

C. FAIRNESS OF REJECTION OF OFFERS FOR NONCONFORMANCE TO REQUIREMENTS OF THE SOLICITATION

After Offers were received, PG&E performed a detailed review of the packages in order to identify deficiencies that needed to be addressed by requesting additional information from Participants and to assess which Offers deviated from the requirements of the solicitation protocol. Most Participants whose Offers were identified as deficient were able and willing to address the missing information. A few did not.

Fifteen Offers were rejected by PG&E for nonconformance with the requirements of the Solicitation Protocol. Also, a few variants of Offers were rejected though other variants of the same Offer were accepted as conforming. PG&E rejected some Offers and variants because they violated the requirement stated in the solicitation protocol that projects for a Purchase and Sale Agreement (e.g. for transfer to utility ownership) must be sited within the state of California. PG&E is not at this point in time considering the purchase of out-of-state power plants through RPS solicitations.

Other offers for PPAs were rejected as nonconforming because they specified a price for delivery at a project busbar in a balancing authority area outside California rather than to a CAISO delivery point. Or they proposed an out-of-state project as a PPA for bundled product delivery, rather than a REC sale or a CAISO-approved pseudo-tie or dynamic scheduling arrangement. Some out-of-state Offers failed to provide a detailed or credible plan about how to deliver power to the CAISO, particularly for intermittent resources, or failed to name a specific point of interconnection to the CAISO where the power will be delivered. The solicitation protocol had cited CPUC Decision 11-01-025 regarding bundled transactions requiring interconnections inside California or using dynamic scheduling. It appeared that some Participants do not understand current requirements for a project to be considered an in-state bundled resource for purposes of RPS compliance.

Similarly, some variants were rejected because they failed to conform to another requirement stated in the protocol for PSAs: "The Project and transmission interconnection must be designed and constructed in conformance with California Independent System Operator's (CAISO) various reliability agreements, procedures, protocols, tariffs, and standards."[9] While this eligibility requirement does not says so in so many words, Arroyo interprets it to disqualify PSAs for in-state generation whose interconnection is outside the CAISO's balancing authority area. Such projects would not operate under the CAISO tariff. PG&E is not considering purchasing generation outside the CAISO through RFOs.

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[9] Pacific Gas and Electric Company, "Renewables Portfolio Standard: 2011 Solicitation Protocol, May 11, 2011 (Updated June 7, 2011)", page 9.

One Offer submitted for a PSA was rejected for non-compliance with the requirement stated in the solicitation protocol that the "Project should utilize a commercially proven, non-solar technology." PG&E is not currently considering solar generation proposals from the RPS RFO for transfer to utility ownership (as opposed to other competitive solicitations focused on pursuing turnkey approaches to utility-owned solar generation).

PG&E rejected another set of Offers that failed to provide basic information required by the solicitation protocol, such as project location, and which explicitly were offered as indicative, non-binding proposals as opposed to the binding and exclusive requirement for participation in the RFO as stated in the protocol. Other Offers were deemed nonconforming to the requirements of the protocol because they proposed new transmission or new shaping-and-firming service arrangements rather than new PPAs, PSAs, unbundled RECs, or biogas sales as requested in the protocol.

In the days immediately following Offer Opening, some Participants sent PG&E corrections and changes to their previously submitted Offers. Arroyo notes that some of these were prompted by deficiency notices e-mailed to the Participants by PG&E, while others were unprompted voluntary efforts of the Participants to address errors they recognized only after shipping the original Offers. Arroyo does not consider the changes, even improvements, in these Offers to have been prompted by "signaling" by PG&E or by an unfair request for "clarifications" by the utility.

Overall, Arroyo's opinion is that PG&E's decisions about which Offers or Offer variants to classify as nonconforming were fair to Participants. There were Offers that were very clearly nonconforming based on explicit deficiencies from the requirements clearly stated in the solicitation protocol; most Offers were clearly conforming. There was also a gray area in between, in which reasonable people could disagree about whether an Offer should be rejected for nonconformance or not; in general the PG&E team gave Participants whose Offers fell into this gray zone the benefit of the doubt and evaluated the proposals. In many of these cases Arroyo would have rejected the proposals. However, none of these accepted Offers from the gray area were selected given their rankings for value and viability.

Another gray area that troubles Arroyo is the failure of several Participants to submit the required Attachment L, PG&E's supplier diversity questionnaire. As described below, it appears that some Participants did not take the supplier diversity evaluation criterion of the RFO and the requirements of the protocol relating to diversity seriously. In future Arroyo would suggest that Offers lacking a completed Attachment L be rejected as non-conforming if PG&E contacts the Participant to correct the deficiency but the Participant fails to do so.

D. REASONABLENESS AND FAIRNESS OF PARAMETERS AND INPUTS

The vast majority of the many parameters and inputs that PG&E used in its evaluation of the 2011 RPS RFO Offers were reasonably and fairly chosen, in Arroyo's opinion. Arroyo identified only one issue regarding the choices PG&E made about parameters and inputs that merits discussion.

PG&E used a discount rate of 7.6% to bring future Offer costs and benefits to a 2011 present value. This value is based on PG&E's approved cost of capital. It represents the approved weighted average cost of capital (WACC) for PG&E, on an after-tax basis.

Arroyo doubts it is appropriate to use a regulated utility's authorized cost of capital as the discount rate for net revenues from PPAs with renewable generation developers. These developers are generally not regulated utilities but are rather private or public companies in the independent power producer (IPP) sector. The cost of equity and cost of debt for the riskier IPP sector are both higher than for regulated utilities. For example, the cost of debt assumed into the Energy Division's 2009 analysis of the Market Price Referent (MPR), an analysis that represents the risks of an IPP developer building a proxy plant under a long-term PPA, was 7.67% compared to PG&E's authorized 6.05%, and the assumed cost of equity underlying the proxy developer was 11.96% vs. PG&E's authorized 11.35%.

Arroyo asserts that the flow of net benefits of power deliveries from independent power companies contracting in long-term PPAs has more risk associated with it than PG&E's risk (e.g. higher credit risk, bankruptcy risk, liquidity risk, development risk) that merits discounting the net benefits at the higher WACC associated with the IPP industry. That suggests that the appropriate WACC to be used when evaluating Offers in this solicitation should be closer to the 8.25% after-tax WACC for the proxy plant used in the 2009 MPR model than to the regulated utility's 7.6%. PG&E disagrees, and believes that cash flows in a PPA secured by a regulated utility's credit should be discounted at a regulated WACC.

Arroyo's opinion is that use of a low discount rate results in valuations that overstate the importance of the most distant years of contract term, when the methodology depends on extrapolated market forward prices. Arroyo views this as a distortion that skews PG&E's value rankings towards preferring long-dated PPAs, and projects with later on-line dates. In particular, the lower discount rate tends to overemphasize the value of Resource Adequacy.

PG&E has a variety of internal controls in place to ensure that selection of inputs is reasonable and fair. The Energy Supply organization relies on a separate and independent risk management function for oversight on power market assumptions used in valuation, and on a financial function for oversight on financial assumptions. The choice of parameters is described in internal protocols. Also, the IE has the opportunity to review the inputs to the valuation model in detail and to raise questions with the team as appropriate.

E. THIRD-PARTY ANALYSIS

In its 2011 solicitation, PG&E outsourced a portion of the analysis of transmission adders to an external consultant. An internal PG&E transmission expert oversaw the work and performed quality control on the product; also, Arroyo had an opportunity to review the third-party work product and compare it to the IE's independent analysis as a check.

F. TRANSMISSION COST ADDERS AND INTEGRATION COSTS

PG&E generally followed its transmission analysis protocols in administering its procedures for market valuation. The team used TRCR proxy costs from the three

California IOUs or data from Phase I or Phase II interconnection studies or interconnection agreements to estimate the cost of network upgrades for new projects interconnecting in congested locations. This is a great deal of transmission information to process in a short period of time and the team should be commended for its success in having developed, acquired, and applied a full set of this data within the deadline for creating a short list.

The team followed the public and non-public protocols for analysis of transmission adders. As stated in the discussion of PG&E's LCBF methodology, there are two areas in which Arroyo disagrees with how this was performed. Both fall within lacunae in the protocols, so PG&E's practice was entirely consistent with its protocols.

- Arroyo believes that transmission cost adders should be estimated for projects that interconnect within California but outside the CAISO's balancing authority area, using the estimates of network upgrade costs provided in those other PTO's interconnection studies. Arroyo considers the valuations of these PPAs to understate the full cost of power from the projects, and the analytic approach to be less than fully fair to projects that interconnect to the CAISO grid.

- In Arroyo's opinion, the lack of estimated LMP multipliers for CAISO intertie points that fall outside the main body of the BAA presents a gap in data inputs. Projects that propose to interconnect to these points are unfairly advantaged vs. projects assigned to recognized LMP zones. Arroyo's opinion is that projects interconnecting to far-flung outposts of the CAISO grid in other states should be evaluated with a recognition that nodal prices there are on average materially lower than those within the core of CAISO service territories due to congestion.

G. AFFILIATE PROPOSALS AND TURNKEY OFFERS

PG&E has more stringent eligibility requirements for renewable energy projects intended for utility ownership through turnkey development and transfer (the utility does not have unregulated affiliates that participated in the RPS RFO). For example, PG&E does not accept proposals for utility-owned generation that is sited outside California or outside the CAISO balancing authority area. In the RPS solicitation PG&E did not accept PSA proposals for solar generation; it separately conducts a competitive solicitation seeking solar photovoltaic generation for utility ownership.

Analytically, PG&E has an extra step in applying the same LCBF methodology to projects proposed for PSAs; it estimates a stream of revenue requirements for the project and the estimated operating and maintenance costs to replace PPA payments as the cost of the PSA. Otherwise the evaluation of turnkey proposals is quite similar to that of PPAs.

H. PG&E'S USE OF ADDITIONAL CRITERIA AND ANALYSIS IN CREATING A SHORT LIST

PG&E's overall approach to creating a short list was to rank PPA Offers for bundled delivery to a CAISO node by net value and to screen out (as a first cut) all Offers that scored below a chosen threshold for project viability. Then the PG&E team went down the list ranked by value, selecting Offers primarily based on highest valuation and higher than threshold viability. These selections were modified by criteria and preferences other than value and viability, described in this section.

PG&E stopped adding highly valued projects to its short list when the total volume of the selections totaled several times the RFO's target of 1% to 2% of PG&E's retail load. The team made a business judgment of how much more than the target would be needed to achieve the goals for the RFO, given a likelihood that Participants would choose exclusive negotiations with other utilities or that Offers would drop out of negotiations at some point.

The team applied different value cutoffs to different classes of projects based on the utility's stated preferences; for example, the valuation cutoff was lower for projects sited within PG&E's service territory than for those interconnecting to other utility's grids. Similarly, the valuation cutoff for Offers of unbundled RECs or RECs plus firm energy was set higher than the cutoff for Offers proposing bundled delivery of energy to a CAISO point. Other situations where the cutoff varied are described below.

1. SERIOUS ENVIRONMENTAL CONCERNS

Appendix K to PG&E's 2011 solicitation protocol states specific subcomponents of the RPS Goals evaluation criterion. Among these is "environmental stewardship", which is identified in the CPUC's Decision 04-07-029 as one of a few designated "qualitative attributes" that the Decision allowed the IOUs to use as the basis for including Offers on a short list, subject to (1) the Offer being within reasonable price proximity to others selected and (2) support from the utility's PRG prior to elevation.

In the 2011 RFO, PG&E's evaluation team screened Offers to identify higher-valued projects with potentially serious environmental impacts; this is the contrapositive of the logic stated in Decision 04-09-027, in that PG&E is using a qualitative attribute to reject Offers from its short list. The team identified only a few Offers as posing sufficiently egregious threats to consider rejection on the basis of the most serious environmental concerns. These typically related to concerns regarding impact to endangered or threatened species from construction of a generating facility in close proximity to critical habitat.

In administrating its methodology, PG&E only rejected one 2011 Offer based solely on serious environmental concerns; it was adjacent to known occurrences of both endangered and fully protected species. Other projects that were identified as posing such concerns were rejected anyway based on inadequate value or viability scores.

2. RESOURCE DIVERSITY

Another component of the RFO Goals evaluation criterion is resource diversity. Attachment K of PG&E's 2011 solicitation protocol cited "Resource Diversity benefits" as a non-quantitative factor identified in CPUC Decision 04-07-029 that could be considered in Offer selection.

PG&E made an effort to increase the resource diversity of its energy mix by altering the value cutoff point below which it rejected Offers. For example, the PG&E team chose to accept baseload generation Offers that were valued below proposals for intermittent generation that were rejected. In a sense, the team chose to create a short list that is quite diverse in resource type (rather than, say, one technology) by applying the valuation criterion differently for different resources, rather than selecting only the highest-valued proposals that had acceptable viability. This will likely result in PG&E contracting with a diverse mix of baseload and peaking, and firm and intermittent resources, at a higher cost to ratepayers than only contracting disproportionately with one type of resource at lower cost.

3. SUPPLIER CONCENTRATION

In this year's solicitation, PG&E stated in its protocol that averting excess supplier concentration would be an evaluation criterion. During the selection process this criterion played a role: the PG&E team limited the volume of selected Offers from any individual counterparty. In some cases where a Participant had its most attractive Offers selected, the PG&E team chose to reject remaining Offers from that Participant even though they were higher valued than Offers from other Participants that were also selected. PG&E also chose to reject some rather large proposals from a developer with whom the utility has already contracted large-volume projects that have not yet achieved commercial operation.

One way that PG&E avoided excess supplier concentration was to reject some rather high-volume Offers with high valuations in favor of smaller Offers with lower valuations from the same developer. This enabled the short list to include a larger number of Participants whose smaller Offers were selected, instead of fewer Participants with only large Offers. The result is a more robust solicitation in the sense that more companies are likely to complete contracts and that PG&E's counterparty credit risk will be diversified. It also means that total ratepayer cost will be higher than an alternative scenario in which only the very highest-valued, viable Offers were selected regardless of volume.

In future years the transparency of solicitations would be improved if this aspect or consequence of the supplier concentration criterion were communicated more clearly in the bidders' conference and in the protocol. Arroyo believes that it is unlikely that most Participants were aware that submitting large projects could disadvantage those proposals.

4. DELIVERY POINT

PG&E stated in its 2011 solicitation protocol a preference for projects that deliver at nodal points within PG&E's service territory, over projects that deliver to other nodal points within the CAISO, to interface points of the CAISO, and to points outside the CAISO.

In the 2011 RPS solicitation, PG&E translated this stated preference into a higher valuation cutoff for in-state projects outside its service territory and a lower valuation cutoff for projects inside. In other words, some projects interconnecting in the SP-15 zone were rejected, whereas if the project with the same resource type, valuation, and viability had proposed to interconnect in NP-15 or ZP-26 it would likely have been selected.

5. COMMERCIAL OPERATION DATE

The solicitation protocol clearly stated PG&E's preference to select Offers that demonstrated flexibility in on-line date. PG&E's bidders' conference presentation stated that the utility would focus on the latter part of the 2014-2016 compliance period. This preference aligns with the utility's current view of its RPS portfolio needs.

It is difficult to separate the application of this preference in Offer selection from an independent effect: that the LCBF valuation methodology assigns a higher value, all else being equal, to projects with later on-line dates than to projects with earlier on-line dates. Arroyo is not aware of any individual Offer that selected solely because of the timing of its COD, as opposed to a better valuation for later on-line date. Nor is Arroyo aware of any Offer that was rejected solely because its proposed on-line date was far from the latter part of the 2014-2016 compliance period. It was clear that fit of projects' timing with the utility's compliance needs was on the mind of the PG&E team as it constructed the short list.

In future RPS solicitations, PG&E should improve the transparency of its selection process by stating its timing preference directly in the protocol. It was evident from debriefings that many Participants were operating under the mistaken belief that PG&E preferred projects with the earliest on-line dates, as was the case in its 2009 RPS RFO.

7. SUPPLIER DIVERSITY

One of the components of the RPS Goals evaluation criterion is whether an Offer will contribute towards PG&E's supplier diversity goals. The solicitation protocol states that

> "It is the policy of PG&E that Women-, Minority-, and Disabled Veteran-owned Business Enterprises (WMDVBE) shall have the maximum practicable opportunity to participate in the performance of Agreements resulting from this Solicitation. PG&E encourages Participants to carry out PG&E's policy and contribute to PG&E's goal by reaching greater than 30% of all procurement with WMDVBEs…The Supplier Diversity evaluation will take into account the Participant's status as a WMDVBE, intent to subcontract with WMDVBEs, and the Participant's own Supplier Diversity Program."

PG&E's evaluation committee scored Offers based on the submittal of Attachment L, a Supplier Diversity Questionnaire.

Historically, only a tiny proportion of IOUs' short-listed Offers or executed PPAs have been executed with WMDVBEs, and PG&E's policy of scoring Offers against this subcriterion is no doubt intended to help address the shortfall between actual procurement of renewable power from WMDVBE's (or from prime contractors that use diverse suppliers as subcontractors) and PG&E's overall supplier diversity goal.

Among developers submitting to the 2011 RPS RFO, only three Participants were WMDVBEs that have been certified by the CPUC Clearinghouse. None of the Offers submitted by certified WMDVBEs scored above the valuation cutoff. Other Participants claimed to be WMDVBEs that had not yet obtained CPUC certification, but review of their ownership suggested that this claim was inaccurate for at least one entity.

Not only were few Participants actual WMDVBEs, but only a subset of Participants agreed to pursue PG&E's stated WMDVBE subcontracting goal (30% of spend). Some Participants whose Offer was shortlisted stated an intent to meet this goal in their proposals but others did not. Arroyo views the overall response from the renewable energy developer community towards PG&E's diversity goals as rather weak. It appears that many Participants failed to take the supplier diversity criterion seriously. In future solicitations there may be opportunities to explain or communicate the diversity goal more clearly, and to more explicitly link Offer selection to a Participant's willingness to commit to some subcontracting goal.

I. ANALYSIS OF PG&E'S SHORT LIST RESULTS

This section provides a review of instances in which Arroyo Seco Consulting disagreed with PG&E's decisions in the administration of its evaluation and selection methodology, and a discussion of the fairness of the decisions.

1. SOURCES OF DISAGREEMENT

Arroyo disagreed with some minor aspects of the PG&E analysis and selection, but these pertained to micro-level issues that did not affect overall selection of a short list. For example, Arroyo and the PG&E team scored Offers using the same Project Viability Calculator; in nearly all cases the scores differed, but relative rankings of Offers were similar overall. Other examples of minor disagreement with no impact on selection include:

- Arroyo disagreed with the estimates of LMP multipliers applied to CAISO delivery points outside California which had not been assigned to an LMP zone;

- Arroyo would have rejected as non-compliant more out-of-state Offers with weak cases for achieving regulatory treatment as bundled in-state resources;

- Arroyo would not have assigned full Resource Adequacy value to some of the out-of-state Offers that proposed to deliver power at CAISO intertie points where PG&E's ability to secure RA import capability is limited.

Arroyo's primary critique of PG&E's short list is that it is too large. Total volume is a multiple of the target for procurement of contracts from the 2011 RFO. By choosing to accommodate a large short list, PG&E has selected some Offers that Arroyo considers marginally attractive, rather than focusing on the highest valued, most viable proposals:

- Because PG&E chose a different cutoff for valuation for different types or locations of resources, it selected several Offers that Arroyo ranked as mediocre in net value. Arroyo would have shortened the short list by rejecting these lower-valued proposals.

- PG&E used a cutoff for viability score to screen out many Offers. However, the team selected a very few Offers that it had scored below this threshold, because of other attributes that PG&E considered sufficiently attractive to outweigh the projects' weaker viability assessments. Arroyo would have rejected those proposals based on the projects' mediocre viability.

- Arroyo's input assumptions to the independent valuation place a lower value on Resource Adequacy capacity than PG&E's do. As a result, Arroyo would have ranked some solar projects lower than PG&E did, and some wind generation projects higher; Arroyo would have considered selecting more wind generation.

Although Arroyo disagreed with the resulting short list that PG&E selected, the basis for these disagreements largely centers on differences in business judgments about relative priorities and choices of numerical inputs. Arroyo believes that the choices the PG&E team made were reasonable and justifiable. For example, PG&E's choice to lower the valuation cutoff for certain resource types and locations was fully consistent with placing a relatively high priority on the non-quantitative sub-criterion of resource diversity and on the stated preference for projects within PG&E's service territory. While Arroyo's relative preferences differ, Arroyo believes that PG&E's relative priorities, based on its business judgment, are reasonable.

Similarly, Arroyo disagrees with PG&E's selection of inputs for its valuation of capacity, but acknowledges that the underlying sources of the inputs which generate the RA value estimates come directly from the CPUC and the California Energy Commission. It seems reasonable for a regulated utility to select parameters in a way that they are consistent with guidance from regulators, though Arroyo believes that better choices are available for inputs.

Separately, Arroyo can offer only a qualified opinion about whether the selection of Offers for sites for development was made fairly. The group within PG&E that analyzes these Offers provided incomplete documentation of the basis for selection decisions. Arroyo disagrees with the shortlisting decisions about these Offers. The CPUC will have a better opportunity to review these if PG&E executes contracts for these in the future.

2. INDEPENDENT OFFER ANALYSES

Arroyo conducted its own rather simplified valuation analysis. PG&E's and Arroyo's valuations generally correlated well for many Offers, but with a fair amount of noise in the comparison, as shown in Figure 3 that compares the two sets of valuations. Some of the differences between valuations include:

- Less value assigned to Resource Adequacy in the independent assessment, which tends to lower the value ranking of projects with the most estimated Net Qualifying Capacity such as solar generation;

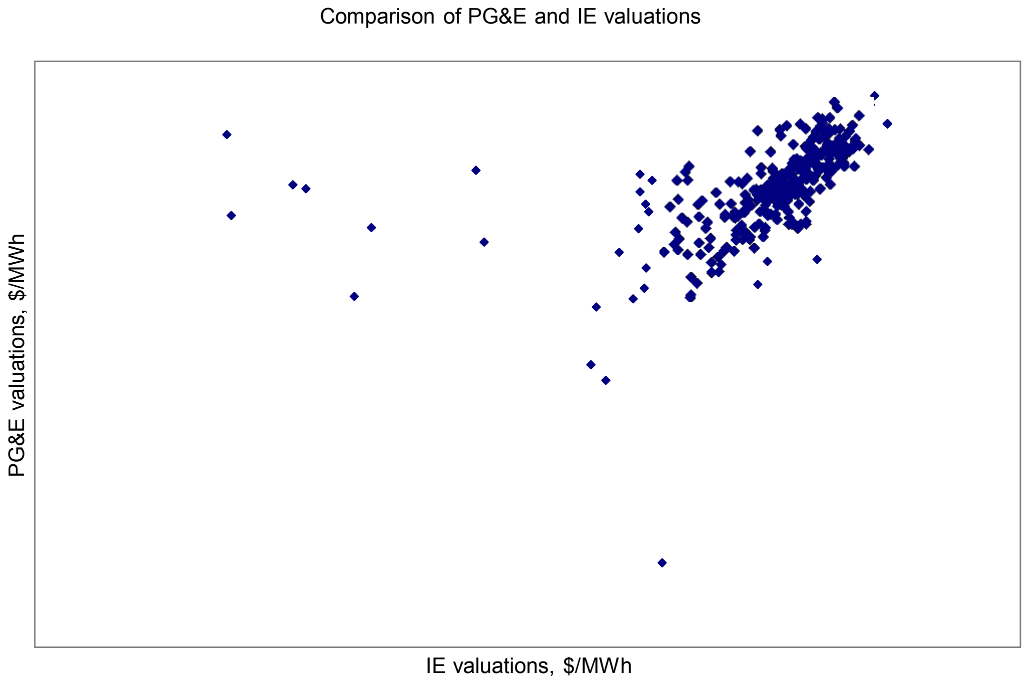
- Less value assigned to projects interconnecting in non-CAISO balancing authority areas;

- Less of a premium assigned to projects with later CODs or longer delivery terms.

This comparison was useful in quality control to identify errors in PG&E's or the IE's input parameters. Also, the comparison helped identify what factors caused specific Offers to be ranked high or low in PG&E's short-listing process, such as the impact of the discount rate assumption, the on-line date, and the size of transmission adder.

Arroyo also scored each Offer for viability independently of PG&E's analysis. This was useful to get an estimate of what the standard error of the Calculator is, and a sense of whether differences in score reflect significant differences in viability or are within the noise of the method. Arroyo emerged from the comparison (shown in Figure 4) with a view that differences of a dozen or fewer points in viability score may not reflect significant differences in the likelihood that project will succeed in attaining commercial operation on schedule, given the modest precision of the tool and the subjectivity of its use.

Figure 3



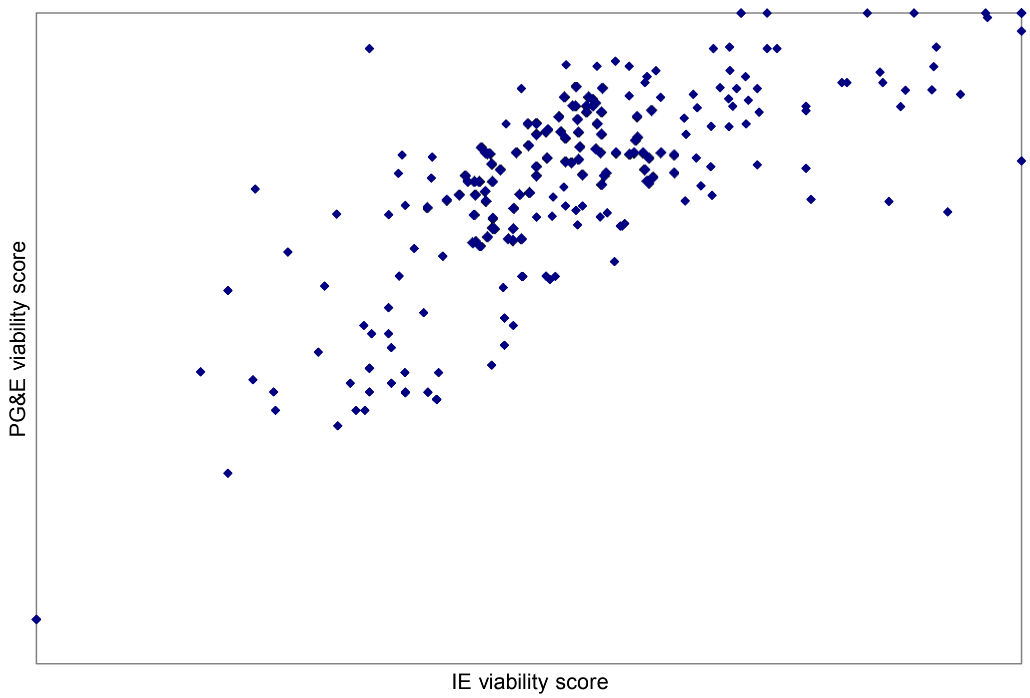
Some of the differences between viability scores include:

- Lower IE scores for projects proposing very large solar photovoltaic facilities;
- Lower IE scores for projects from developers with experience only in distributed generation (e.g. beyond the meter) projects rather than wholesale generation;
- Lower IE scores for projects for which specific network upgrades are as yet poorly characterized.

3. RECTIFYING DEFICIENCIES OF REJECTED OFFERS

PG&E communicated early to several Participants about basic deficiencies in their Offer packages and provided them with an opportunity to correct these deficiencies by completing or correcting their original submissions. None of these original deficiencies caused rejection from the short list, as far as Arroyo can discern. Many of the issues related to failure to complete an Attachment D offer form fully, using the final version of that form, or omission of the most recent CAISO or PTO interconnection study.

Figure 4



Given the robustness of the solicitation and the large number of Offer variants, PG&E did not collect every piece of information required by the protocol from every Participant. Some Participants had obtained interconnection studies for their project but did not submit copies with their proposals. Arroyo observes that in these cases the missing information would not have made a difference to the selection decision. PG&E made a concerted effort to obtain copies of these studies for most of these projects. By this point it was evident which Offers had proposed uncompetitive, high prices and were unlikely to be short-listed.

4. OVERALL FAIRNESS OF ADMINISTRATION

Despite a variety of minor disagreements, Arroyo Seco Consulting's overall judgment is that PG&E's administration of its protocols to arrive at a short list for the 2011 RPS RFO was fair, unbiased, consistent, and reasonable.

Most disagreements between Arroyo and the PG&E team fall into the category of choices that Arroyo would have not made if it were administering the solicitation, but that Arroyo agrees are choices a reasonable person could make if that person had different priorities or emphases regarding the weights assigned to evaluation criteria. Arroyo believes that PG&E's preferences and its choices are within the realm of "reasonable business judgment" that the CPUC allows IOUs to exercise in energy procurement.

5. FAIRNESS OF PROJECT-SPECIFIC NEGOTIATIONS

This chapter provides an independent review of the extent to which PG&E's negotiations with the Nevada Irrigation District for a new contract for delivery of renewable and non-renewable energy were conducted fairly.

Arroyo observed several negotiation sessions between PG&E's and NID's representatives. Arroyo was also able to review draft term sheets and contracts in order to identify specific proposals and counterproposals the parties made regarding contract terms in the course of discussion over more than a year.

Based on this review, Arroyo did not identify any situations in which PG&E provided NID with concessions in contract terms that the IE considered to be materially unfair to ratepayers. Nor did PG&E provide NID with information that might have unfairly advantaged the seller compared to its competitors. The starting point for negotiations was PG&E's 2011 RPS Form Agreement. Because of the nature of the hydro resource and the physical nature of NID's and PG&E's assets, several changes to provisions of that standard form were made so that the resulting PPA has numerous variances from PG&E's standard RPS contract. These are described in greater detail in the narrative below.

Arroyo's opinion is that, overall, the negotiations between PG&E and NID were conducted fairly; the resulting contract retains most of the ratepayer protections afforded by PG&E's Form Agreement. Arroyo does not believe that NID's competitors were materially disadvantaged by how the negotiations were conducted given the structure of the contract.

A. BACKGROUND INFORMATION

NID owns and operates four hydroelectric generation facilities whose output will be provided to PG&E under the PPA[10]:

- Chicago Park Powerhouse, 39.5 MW contract capacity, commenced operation in 1965;
- Dutch Flat Powerhouse No. 2, 26 MW, 1965;
- Rollins Powerhouse, 13 MW, 1980; and
- Bowman Powerhouse, 3.6 MW, 1986.[11]

[10] NID owns three other small hydroelectric units not covered by this PPA whose output is sold to PG&E under separate contracts.

Chicago Park is larger than the 30-MW cutoff to be treated as a small hydroelectric facility for the purposes of the California Energy Commission's eligibility rules; the other three facilities are eligible renewable resources for the purpose of compliance with California's Renewables Portfolio Standard (RPS).

The output of the Bowman Powerhouse has been contracted for sale to PG&E under an Interim Standard Offer #4 Qualifying Facility (QF) agreement since August 1986. [redacted]

NID owns reservoirs, dams, and conduits that have been in operation since the 1850s. NID and PG&E partnered in the 1950s to develop the Yuba-Bear Hydroelectric Project, including dams, conduits, and electric transmission; the Chicago Park and Dutch Flat No. 2 generation facilities were part of the infrastructure of that development on the Bear River and the Middle Fork of the Yuba River. PG&E had previously developed dams, conduits, transmission, and powerhouses on the Yuba and Bear Rivers, and the water operations of the PG&E and NID systems which drive powerhouse production are deeply intertwined. The contracts under which NID sells power to PG&E for the Rollins facility and for the Chicago Park and Dutch Flat No. 2 facility expire at the end of April 2013 and the end of June 2013 respectively. The new PPA was negotiated to supplant the prior contracts going forward and to incorporate the Bowman powerhouse when its existing contract expires at the end of 2017.

B. PRINCIPLES FOR EVALUATING THE FAIRNESS OF NEGOTIATIONS

Arroyo took into account several principles to evaluate the degree of fairness with which NID was treated in negotiations.

- Were sellers treated fairly and consistently by PG&E during negotiations? Were all sellers given equitable opportunities to advance their Offers towards final PPAs? Were individual sellers given unique opportunities to move their proposals forward or concessions to improve their contracts' commercial value, opportunities not provided to others?

- Was the distribution of risk between seller and buyer in the PPAs distributed equitably across PPAs? Did PG&E's ratepayers take on a materially disproportionate share of risks in some contracts and not others? Were individual sellers given opportunities to shift their commercial risks towards ratepayers, opportunities that were not provided to others?

[11] For 2011 the CAISO counted average Net Qualifying Capacity for the four projects of 38 MW, 26 MW, 9.7 MW, and 1.1 MW respectively.

- Was non-public information provided by PG&E shared fairly with all sellers? Were individual sellers uniquely given information that advantaged them in securing contracts or realizing commercial value from those contracts?

- If any individual seller was given preferential treatment by PG&E in the course of negotiations, is there evidence that other sellers were disadvantaged by that treatment? Were other proposals of comparable value to ratepayers assigned materially worse outcomes?

C. NEGOTIATIONS BETWEEN NEVADA IRRIGATION DISTRICT AND PG&E

NID and PG&E began discussions about how best to proceed with a new PPA in late 2010 (the parties have had separate but related discussions about how to replace the coordinated water operations provisions of the expiring agreement, which would deal with wheeling NID-owned water through PG&E conduits and canals and with allocation of water). Negotiations began in the spring of 2011 as PG&E provided an initial draft term sheet to NID; discussions continued for nearly year and culminated in a PPA that was executed on May 9, 2012. Some of the issues that were addressed in the negotiation included:

- [redacted]

[redacted]

[redacted]

12 [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[13] [redacted]

- FERC relicensing. NID is in the process of applying for relicensing of the four powerhouses; the current FERC license for the Yuba-Bear Hydroelectric Project expires in April 2013. The parties agreed that if as a result of new license conditions the expected output of the facilities decreases more than 10% then PG&E can reduce the fixed payment amount.

- Capacity and efficiency testing. [redacted] provisions in the contract for initial and subsequent tests of the powerhouses' capacity and efficiency. These tests can lead to a reset of contract capacity. If unit efficiency rating drops below 90%, NID can attempt to cure the deficiency and if unsuccessful the parties would negotiate a reduction in contract price. These provisions enhance ratepayer protections, since the PPA lacks the protections of the guaranteed energy production obligation of PG&E's Form Agreement.

- CAISO requirements. The expiring partnership agreement was crafted decades before the creation of the California Independent System Operator. [redacted] include the various obligations and requirements associated with operating in the modern CAISO market that are required in the utility's 2011 Form Agreement. This includes such obligations as meeting CAISO expectations for Resource Adequacy reporting, obeying CAISO curtailment orders, meeting the CAISO's requirements for outage scheduling and notification, paying for a specified portion of CAISO imbalance charges caused by forced outages, etc. It also means that NID will meet the requirements for Bowman powerhouse to obtain a FERC-jurisdictional interconnection (such as a CAISO revenue-quality meter) by the time the existing QF contract expires and that generator's output is included in the PPA.

- [redacted]

- [redacted]

- [redacted]

- [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

14 [redacted]

[redacted]

- [redacted]

- Betterments, Improvements, and New Powerhouses. [redacted]

  NID and PG&E agreed that in the scenario in which a new powerhouse is built, NID would offer PG&E the right of first offer for sale from the new facility at the same terms as the PPA except for price, which NID would propose. Any such new agreement would be subject to CPUC approval.

  In the scenario in which improvements to existing powerhouses provide more energy, no increase in payment is envisaged. In a scenario in which improvements to existing powerhouses result in an increase in capacity that is demonstrated by testing, NID would need PG&E's consent, and the parties would negotiate a mutually agreeable change to the PPA (such as an increase in fixed payment) subject to CPUC approval.

D. DEGREE OF FAIRNESS OF PROJECT-SPECIFIC NEGOTIATIONS

The starting point for drafting the PPA with NID was PG&E's 2011 RPS Form Agreement, which serves as the basis for contracting with other sellers. Numerous changes to the Form were made, but the majority of these were either to delete provisions that are irrelevant to an existing set of hydroelectric plants or to customize the contract to the peculiar circumstances of the operation of hydro facilities that are intertwined with PG&E operations. There are very few modifications to the Form Agreement that would raise issues about whether ratepayers or competing generators were treated unfairly. [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

---

15 [redacted]

16 [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Overall, Arroyo's opinion is that the negotiations with NID were handled fairly:

- Other sellers with proposals of comparable valuation and viability have been given comparable opportunities to move their contracts forward. NID was not provided with unique concessions to enhance its contract's value.

- The distribution of risk between PG&E and NID is comparable to that in other contracts with hydro projects; [redacted]

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17 [redacted]

[redacted]

- Arroyo does not believe that at any time PG&E provided any information to NID that may have advantaged the seller compared to its competitors.

- [redacted]

6. MERIT FOR CPUC APPROVAL

This chapter provides an independent review of the merits of the contract between PG&E and Nevada Irrigation District against criteria identified in the Energy Division's 2011 RPS IE template.

A. CONTRACT SUMMARY

On May 9, 2012, PG&E and NID executed a contract for delivery of both renewable and non-renewable energy from four of NID's hydroelectric powerhouses: Bowman, Chicago Park, Dutch Flat No. 2, and Rollins. These existing, operating facilities are located along the Bear River in Nevada and Placer Counties[18] and Canyon Creek in Nevada County. The twenty-year delivery term for Chicago Park, Dutch Flat No. 2, and Rollins powerhouses would begin in July 2013; for Bowman powerhouse it would begin in 2017 after the end of the term of Bowman's existing Qualifying Facilities agreement.

B. NARRATIVE OF EVALUATION CRITERIA AND RANKING

The 2011 template for IEs provided by the Energy Division calls for a narrative of the merits of the proposed project on the criteria of contract price, portfolio fit, and project viability.

<u>CONTRACT PRICE AND MARKET VALUATION</u>

Arroyo has compared the net value of the NID contract to relevant peer groups of previously and currently offered competing sources of RPS-eligible energy, using the results of both PG&E's analysis and a simpler but independent model. Based on those comparisons, Arroyo opines that the market valuation of the NID contract likely ranks as moderate to high compared to relevant peer groups of competing proposals, and the contract price likely ranks as low. [redacted]

Contract Price. [redacted]

[18] The Bear River serves as the boundary between the two counties in the vicinity of the projects.

[redacted]

The approved 2011 Market Price Referent for twenty-year PPAs that begin deliveries in 2013 is $93.75/MWh. [redacted]

[19] Using recent historical averages, the non-RPS eligible energy from Chicago Park powerhouse has been somewhat less than half of total deliveries from the four powerhouses in total.

[20] [redacted]

[redacted]

[redacted]

Market Valuation. PG&E estimated the value of NID's deliveries under the PPA, [redacted]

[redacted]

[redacted]

---

21 [redacted]

22 If the Commission adopts compliance rules for the RPS program that allow PG&E to "bank" excess procurement of renewable energy from the NID PPA in the first and second compliance period for use in the third compliance period, then this version of the portfolio-adjusted valuation metric has understated the ratepayer benefits of NID's deliveries.

Arroyo independently estimated the value of the NID PPA, using its own assumptions about hydrologic averages and the value of the non-RPS-eligible energy. This estimate places the PPA in the highest-valued decile when compared to Offers to PG&E in its 2011 renewable solicitation, and in the highest-valued quartile when compared to PG&E's initial short list for that solicitation.

PORTFOLIO FIT

Arroyo ranks the NID contract's fit with PG&E's supply portfolio needs as moderate. [redacted]

The NID powerhouses have a modest degree of dispatch flexibility, which is constrained by the limitations on volume of upstream storage and by PG&E's and NID's general aversion to wasting water through suboptimal scheduling. Operations seasonality depends on snowpack and rainfall, but generally the output correlates well with the summer months in which PG&E's' portfolio has the greatest need. These facilities have their highest output in the April through September period, which follows PG&E demand needs in summer but provides more production in April and May than PG&E's overall load shape. The Chicago Park and Dutch Flat No. 2 powerhouses also have the ability to provide spinning and non-spinning reserve to the system.23

Arroyo considers the portfolio fit of NID's production with the utility's needs to be moderate.

PROJECT VIABILITY

In Arroyo's opinion, the physical project viability of the existing, operating NID facilities is high. The powerhouses have operated for decades. An existing, currently operating project is more viable, in a physical rather than economic sense, than any proposed as-yet-unbuilt generator.

Project development experience. NID developed the four powerhouses covered in the PPA as well as others. It has more recent development experience than the 1980s construction of the Rollins and Bowman facilities; in 2002 NID rebuilt the Combie North powerhouse with new turbine/generator, penstock, and building, using an outside EPC contractor.

[23] Neither Arroyo nor PG&E have factored the ratepayer benefit of these ancillary services into the valuation estimates for the contract.

Ownership/O&M experience. NID has owned and operated the four powerhouses since they were constructed.

Technical feasibility. The hydroelectric generating technology employed at the four powerhouses was already stable when the Yuba-Bear project was constructed in the 1960s.

Resource quality. The annual production from the powerhouses varies considerably depending on snowpack. Also, there is some risk that new conditions may be placed on minimum flow release on the river associated with FERC relicensing of the Yuba-Bear project. The PPA allows the powerhouses to suffer up to a 10% reduction in expected production due to such new conditions before PG&E can revise the contract price downwards. [redacted]

[redacted]

Manufacturing supply chain. As existing facilities, the NID powerhouses do not rely on new sources of hardware.

Site control. NID owns the powerhouses; the Yuba-Bear hydroelectric project is operated under a FERC license that expires in 2013. While there is some likelihood that new constraints imposed under a new license could affect project operations, it is extremely unlikely that NID would be denied use of the powerhouses to generate power.

Permitting. NID currently holds all permits required for continued operation of the powerhouses but needs the proposed new forty-year FERC license for the Yuba-Bear projects in order to continue operations after the existing license expires in April 2013.

Project financing status. The Yuba-Bear hydroelectric project is built and operating. As a public agency, NID uses tax-exempt bond financing for its capital needs; for example, it issued $26 million (face value) in new bonds in 2011 primarily to finance the acquisition of new water pipelines. NID's pledges to secure the bonds include net revenues from hydroelectric sales from the four power plants covered by the new PPA (revenues from the original agreement were pledged to service original construction debt). The bonds were rated AA+ by Standard and Poor's (e.g. the same credit rating as the U.S. Treasury) and AA by Fitch, demonstrating the considerable strength of the District's financial position.

Interconnection progress. The existing powerhouses are already interconnected to the CAISO grid. The Bowman powerhouse began operations in 1986 under a CPUC-jurisdictional interconnection; the PPA requires NID to obtain a CAISO participating generator agreement and a CAISO-quality revenue metering arrangement before Bowman powerhouse converts from its existing agreement to the new PPA in 2017. Because the facility is already interconnected and delivering power into the CAISO grid, Arroyo would not anticipate any issues for NID securing a FERC-jurisdictional interconnection beyond possible metering and telemetry upgrades.

Transmission requirements. PG&E's transmission facilities already take the output of the four NID powerhouses at their respective transformers. [redacted] Also, the CAISO already credits the four powerhouses with Net Qualifying Capacity providing Resource Adequacy benefits to PG&E customers.

Reasonableness of COD. As existing generators, there are no physical impediments to continued operation of the NID facilities.

The viability score for NID's generation would rank among the highest-scored proposals submitted to PG&E in the 2011 RPS RFO.

RPS GOALS

[redacted] Entering into this transaction would not advance PG&E and the state towards the 20% biomass goal set by Executive Order S-06-06.

One interesting attribute of NID's generation is that it is geographically sited in the CAISO's Sierra area, which was identified in both 2011 and 2012 Local Capacity Technical Analysis studies as deficient in local capacity resources. More specifically, the South of Palermo sub-area was identified as deficient by 313 MW for 2011 and by 36 MW for 2012 under "Category B"[24]: at summer peak, load would need to be shed immediately after the first contingency. All four NID powerhouses in this PPA are in the South of Palermo sub-area. While there seems little risk that the NID generators would cease operation if PG&E failed to contract for their output, because other entities such as wholesale marketers would likely be willing to purchase NID's energy, it appears that these units play a significant role in maintaining grid reliability in the Sierra area. The CAISO anticipates that the deficiency could be remedied by major network upgrades to PG&E's grid including line voltage upratings in the vicinity of Vaca-Dixon and Davis, which could be in place by 2015.

C. DISCUSSION OF MERIT FOR APPROVAL

In Arroyo's opinion, PG&E's contract with Nevada Irrigation District merits CPUC approval.

[24] The CAISO's 2013 study identified no local deficiency in the Sierra area under Category B, which considers a scenario with an n-1 contingency of a single transmission failure, though there is still a deficiency using Category C that employs an n-2 contingency, or double line failures.

Arroyo's independent but simpler valuation ranks the NID contract as high in net value compared to competing alternatives; PG&E's LCBF analysis suggests that the contract ranks as moderate in net market value and high in portfolio-adjusted value. Similarly, the average contract price will likely rank as low compared to competing alternatives available to PG&E. The structure of the contract and the nature of the hydro resource imply a wide degree of year-to-year uncertainty about the $/MWh price that PG&E's customers would pay for NID's RPS-eligible energy, but using reasonable assumptions for hydro conditions over the twenty-year delivery term and for possible new conditions to be imposed by FERC relicensing, the average price of this power over twenty years will likely rank low compared to currently or recently available alternatives.

The project viability of NID's powerhouses is quite high because they are existing, operating facilities. Arroyo regards the NID contract as ranking as moderate in portfolio fit; [redacted] The powerhouses contribute to grid reliability in the CAISO's resource-deficient Sierra area.

Arroyo believes that PG&E's project-specific negotiations with NID were conducted fairly. Based on its moderate to high valuation, low contract price, high viability, and moderate portfolio fit, Arroyo's opinion is that this contract merits CPUC approval.

Appendix D

Public

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	(Unaudited) Three Months Ended March 31,	
(in millions)	**2012**	**2011**
Operating Revenues		
Electric	$ 2,771	$ 2,616
Natural gas	869	980
Total operating revenues	3,640	3,596
Operating Expenses		
Cost of electricity	859	888
Cost of natural gas	343	508
Operating and maintenance	1,366	1,226
Depreciation, amortization, and decommissioning	584	490
Total operating expenses	3,152	3,112
Operating Income	488	484
Interest income	1	2
Interest expense	(168)	(171)
Other income, net	23	17
Income Before Income Taxes	344	332
Income tax provision	113	131
Net Income	231	201
Preferred stock dividend requirement	3	3
Income Available for Common Stock	$ 228	$ 198

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS

	(Unaudited)	
	Balance At	
(in millions)	March 31, 2012	December 31, 2011
ASSETS		
Current Assets		
Cash and cash equivalents	$ 45	$ 304
Restricted cash ($56 and $51 related to energy recovery bonds at March 31, 2012 and December 31, 2011, respectively)	385	380
Accounts receivable		
Customers (net of allowance for doubtful accounts of $80 and $81 at March 31, 2012 and December 31, 2011)	926	992
Accrued unbilled revenue	614	763
Regulatory balancing accounts	1,425	1,082
Other	821	840
Regulatory assets ($227 and $336 related to energy recovery bonds at March 31, 2012 and December 31, 2011, respectively)	1,024	1,090
Inventories		
Gas stored underground and fuel oil	97	159
Materials and supplies	273	261
Income taxes receivable	212	242
Other	188	213
Total current assets	6,010	6,326
Property, Plant, and Equipment		
Electric	36,329	35,851
Gas	12,015	11,931
Construction work in progress	2,011	1,770
Total property, plant, and equipment	50,355	49,552
Accumulated depreciation	(16,106)	(15,898)
Net property, plant, and equipment	34,249	33,654
Other Noncurrent Assets		
Regulatory assets	6,565	6,506
Nuclear decommissioning trusts	2,134	2,041
Income taxes receivable	413	384
Other	330	331
Total other noncurrent assets	9,442	9,262
TOTAL ASSETS	$ 49,701	$ 49,242

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS

(in millions, except share amounts)	(Unaudited) Balance At March 31, 2012	(Unaudited) Balance At December 31, 2011
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-term borrowings	$ 1,401	$ 1,647
Long-term debt, classified as current	50	50
Energy recovery bonds, classified as current	321	423
Accounts payable		
Trade creditors	873	1,177
Disputed claims and customer refunds	658	673
Regulatory balancing accounts	641	374
Other	522	417
Interest payable	788	838
Income taxes payable	118	118
Deferred income taxes	165	199
Other	1,562	1,628
Total current liabilities	7,099	7,544
Noncurrent Liabilities		
Long-term debt	11,418	11,417
Regulatory liabilities	4,927	4,733
Pension and other postretirement benefits	3,391	3,325
Asset retirement obligations	1,620	1,609
Deferred income taxes	6,347	6,160
Other	2,071	2,070
Total noncurrent liabilities	29,774	29,314
Commitments and Contingencies (Note 10)		
Shareholders' Equity		
Preferred stock	258	258
Common stock, $5 par value, authorized 800,000,000 shares, 264,374,809 shares outstanding at March 31, 2012 and December 31, 2011	1,322	1,322
Additional paid-in capital	4,181	3,796
Reinvested earnings	7,259	7,210
Accumulated other comprehensive loss	(192)	(202)
Total shareholders' equity	12,828	12,384
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 49,701	$ 49,242

Appendix E

Public

Summary of Earnings of

Pacific Gas and Electric Company

PACIFIC GAS AND ELECTRIC COMPANY
ALL OPERATING DEPARTMENTS
REVENUES, EXPENSES, RATE BASES AND RATES OF RETURN
YEAR 2010 RECORDED
ADJUSTED FOR RATEMAKING
(000$)

Line No.		Electric Operations	Gas Operations	Total Utility Operations
1	**Operating Revenue**	10,272,443	3,341,762	13,614,205
2	Operation Expenses	6,199,632	2,187,052	8,386,685
3	Maintenance Expenses	600,193	141,615	741,808
4	Depreciation Expense	1,003,133	337,696	1,340,829
5	Amort & Depletion of Utility Plant	139,785	34,667	174,452
6	Regulatory Debits	0	0	0
7	(Less) Regulatory Credits	0	0	0
8	Taxes Other Than Income Taxes	286,256	78,601	364,858
9	Federal Income Taxes	506,609	153,970	660,579
10	State Income Taxes	71,736	37,977	109,713
11	(Less) Gains from Disp of Utility Plant	(1,190)	(351)	(1,541)
12	Losses from Utility Plant	0	0	0
13	(Less) Gains from Disposition Utility Plant	(18)	0	(18)
14	**Operating Income**	1,466,307	370,534	1,836,840
15	Weighted Average Rate Base	16,721,231	4,531,858	21,253,089
16	**Rate of Return**	**8.77%**	**8.18%**	**8.64%**