Pacific Gas and Electric Company®

**Brian K. Cherry**
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Regulatory Relations

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September 18, 2009

**Advice 3527-E**
(Pacific Gas and Electric Company ID U39 E)

Public Utilities Commission of the State of California

**<u>Subject:</u>** **Contract for Procurement of Renewable Energy Resources Resulting from PG&E's Wind Energy Purchase Agreement with PacifiCorp**

# I. INTRODUCTION

## A. Purpose and Overview

Pacific Gas and Electric Company ("PG&E") seeks California Public Utilities Commission ("Commission" or "CPUC") approval of a wind energy purchase agreement ("2010-2012 Agreement") that PG&E has executed with PacifiCorp. PG&E submits the 2010-2012 Agreement for CPUC Approval to establish PG&E's ability to recover the cost of payments made pursuant to the 2010-2012 Agreement through its Energy Resource Recovery Account ("ERRA").

The 2010-2012 Agreement consists of a Confirmation to an Edison Electric Institute ("EEI") master power purchase and sale agreement between PG&E and PacifiCorp ("EEI Master Agreement"). The Commission's approval of the 2010-2012 Agreement will authorize PG&E to accept deliveries of approximately 655 gigawatt hours ("GWh") in each of 2010 and 2011 and 657 GWh in 2012 of Renewables Portfolio Standard ("RPS")-eligible energy from a pool of eight wind facilities located in Washington, Wyoming, and Idaho (each, a "Project," collectively, the "Projects"). PacifiCorp owns seven of these facilities and has rights to the generation from the eighth facility. The Projects are currently operational and seven of the eight Projects have been certified by the California Energy Commission ("CEC") as eligible renewable energy resources.

Deliveries under the 2010-2012 Agreement will commence on January 1, 2010 and will continue through December 31, 2012. These deliveries will contribute to PG&E's 20 percent portfolio goal.

The 2010-2012 Agreement was initiated through bilateral negotiations, and negotiations occurred during the pendency of the 2008 RPS Solicitation. Consistent with the protocol used for review of RPS contracts resulting from the 2008 RPS Solicitation and contracts resulting from bilateral negotiations, PG&E has included Confidential Appendices A through D and F through H, which demonstrate the reasonableness of the 2010-2012 Agreement. As discussed below, PG&E requests confidential treatment of the information contained in these Appendices.

PG&E requests that the Commission issue a resolution no later than **November 20, 2009** approving the 2010-2012 Agreement in its entirety, and all payments to be made by PG&E under the 2010-2012 Agreement, and containing the findings required by the definition of CPUC Approval adopted by Decision ("D.") 07-11-025 and D.08-04-009.[1]

### B. Detailed Description of the Projects

The 2010-2012 Agreement involves deliveries from eight operational wind facilities located in Washington, Wyoming, and Idaho. Under the 2010-2012 Agreement, bundled electric energy and associated Green Attributes will be delivered to PG&E at the California-Oregon Border ("COB"). The 2010-2012 Agreement includes a firming and shaping service whereby intermittent energy from each of the Projects is firmed and shaped and delivered to PG&E as firm energy at COB.

The following table summarizes the substantive features of the 2010-2012 Agreement:

| | |
|---|---|
| **Owner / Developer** | PacifiCorp |
| **Technology** | Wind |
| **Capacity (MW)** | 100 MW |
| **Capacity Factor** | Goodnoe Hills<br>Klickitat, Washington: 32%<br>Seven Mile Hill I<br>Carbon County, Wyoming: 40%<br><br>Seven Mile Hill II |

[1] As provided by D.07-11-025 and D.08-04-009, the Commission must approve the 2010-2012 Agreement and payments to be made thereunder, and find that the procurement will count toward PG&E's RPS procurement obligations.

| | |
|---|---|
| | Carbon County, Wyoming: 40%<br><br>Glenrock I<br>Converse County, Wyoming: 37%<br><br>Rolling Hills<br>Converse County, Wyoming: 34%<br><br>Glenrock III<br>Converse County, Wyoming: 36%<br><br>Marengo II<br>Columbia County, Washington: 31%<br><br>Wolverine Creek<br>Bonneville and Bingham Counties, Idaho: 31% |
| **Expected Generation (GWh/Year)** | Approximately 655 GWh in each of 2010 and 2011 and 657 GWh in 2012[2] |
| **Online Date (if existing, the contract delivery start date)** | January 1, 2010 delivery start date |
| **Contract Term** | 3 years |
| **New or Existing Facility** | New facilities that are currently operational |
| **Location (include in/out-of-state) and Control Area e.g., CAISO, BPA)** | Goodnoe Hills<br>Klickitat, Washington<br>Control Area: BPA<br><br>Seven Mile Hill I<br>Carbon County, Wyoming<br>Control Area: PacifiCorp (East)<br><br>Seven Mile Hill II<br>Carbon County, Wyoming<br>Control Area: PacifiCorp (East) |

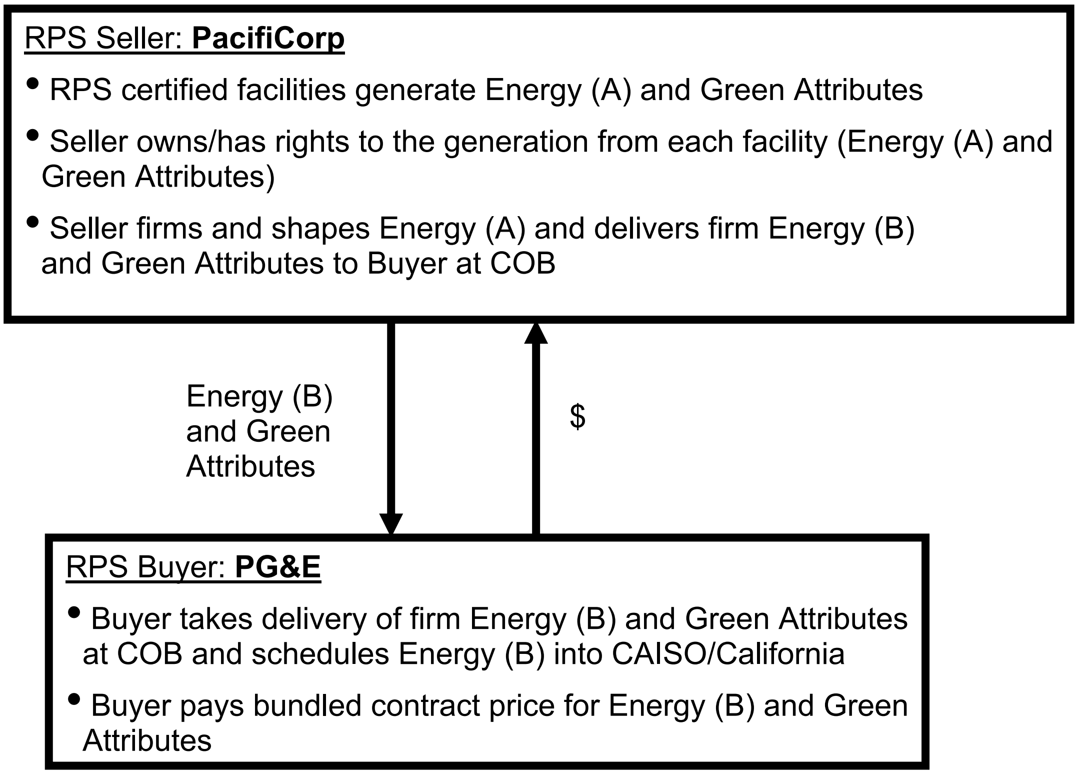
[2] Under the terms of the 2010-2012 Agreement, certain circumstances may cause the deliveries of RPS-eligible energy to be reduced to approximately 492 GWh.

| | |
|---|---|
| | Glenrock I<br>Converse County, Wyoming<br>Control Area: PacifiCorp (East)<br><br>Rolling Hills<br>Converse County, Wyoming<br>Control Area: PacifiCorp (East)<br><br>Glenrock III<br>Converse County, Wyoming<br>Control Area: PacifiCorp (East)<br><br>Marengo II<br>Columbia County, Washington<br>Control Area: PacifiCorp (West)<br><br>Wolverine Creek<br>Bonneville and Bingham Counties, Idaho<br>Control Area: PacifiCorp (East) |
| **Price relative to MPR** | Contract pricing generally compares favorably to the 10-year 2008 market price referent ("MPR") |

The Confirmation is provided in Confidential Appendix G. The public portion of the EEI Master Agreement is provided in Appendix J. A contract analysis is provided in Confidential Appendix D.

Under the 2010-2012 Agreement, PacifiCorp will schedule and deliver 100 MW per hour during the first, second and fourth quarters of 2010-2012 for a total of 655 GWh in each of 2010 and 2011, and 657 GWh in 2012 of bundled renewable energy from the Projects delivered as a firmed and shaped product at COB.

Diagram of Delivery Structure
for PacifiCorp RPS Transaction




This structure complies with the CEC's RPS eligibility requirements for firmed and shaped deliveries of out-of-state power where deliveries occur at a different time than generation.[3]

## II. THE 2010-2012 AGREEMENT IS CONSISTENT WITH THE COMMISSION'S RPS-RELATED DECISIONS

### A. Consistency with PG&E's Adopted RPS Plan and Solicitation

PG&E's 2008 renewable procurement plan ("2008 Plan") was conditionally approved in D.08-02-008 on February 14, 2008. As required by statute, the 2008 Plan includes an assessment of supply and demand to determine the optimal mix of renewable generation resources, consideration of compliance flexibility mechanisms established by the

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[3] *See* California Energy Commission Renewables Portfolio Standard Eligibility Guidebook, Third Edition, CEC-300-2007-006-ED3-CMF, adopted December 19, 2007, at 23-24.

Commission, and a bid solicitation setting forth the need for renewable generation of various operational characteristics.[4]

The goal of PG&E's 2008 Plan was to procure approximately one to two percent of its retail sales volume, or between 800 GWh and 1,600 GWh per year. With expected RPS-eligible energy deliveries of approximately 655 GWh in each of 2010 and 2011 and 657 GWh in 2012, the 2010-2012 Agreement meets the criteria for renewables procurement contained in the 2008 Plan. Projects capable of providing actual deliveries with only a short or no delay are especially valuable to PG&E.

The 2010-2012 Agreement is also consistent with PG&E's approved RPS Plan because it was evaluated consistent with the review protocol in the 2008 RPS Solicitation.

### B. Consistency with PG&E's Long Term Procurement Plan

PG&E's 2006 long-term procurement plan ("LTPP") stated that PG&E would aggressively pursue procurement of RPS-eligible renewable resources. In approving PG&E's 2006 LTPP, the Commission noted that development of renewable energy is "of great importance to the Governor, the State of California, and the Commission."[5] The 2010-2012 Agreement is consistent with PG&E's 2006 LTPP and with Commission policy regarding renewable energy expressed in the decision approving PG&E's 2006 LTPP.

### C. Consistency with Commission Guidelines for Bilateral Contracting

The Commission has developed guidelines pursuant to which 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."[6] Later, in D.06-10-019, the Commission again held that bilateral contracts were permissible provided that they were at least one month in duration, and also found that such contracts must be reasonable and submitted for Commission approval by advice letter.[7] Also in that decision, the Commission stated that bilateral

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[4] Pub. Util. Code § 399.14(a)(3).

[5] D.07-12-052 at 73.

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

[7] D.06-10-019 at 29.

contracts were not eligible for supplemental energy payments.[8] Based on D.03-06-071 and D.06-10-019, the Commission set forth the following four requirements for approval of bilateral contracts in a recent 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.[9] The Commission noted that it would be developing evaluation criteria for bilateral contracts, but that the above four requirements would apply in the interim.[10]

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

The 2010-2012 Agreement satisfies both the four requirements listed above and the requirements of D.09-06-050. The 2010-2012 Agreement is being submitted for approval via this Advice Letter and is not eligible for AMFs because it resulted from bilateral negotiations. The 2010-2012 Agreement has a three year term and is therefore longer than one month in duration. Finally, the 2010-2012 Agreement is reasonable when considered against the standards used for evaluating contracts resulting from PG&E's 2008 RPS Solicitation, both with respect to price and other terms, as PG&E explains in this Advice Letter and in the attached Confidential Appendices. The Commission should therefore approve the 2010-2012 Agreement.

### D. Consistency of Bid Evaluation Process with Least-Cost Best Fit Decision

The RPS statute requires PG&E to procure the least cost, best fit ("LCBF") eligible renewable resources.[11] The LCBF decision directs the utilities to use certain criteria in their bid ranking.[12] It offers guidance regarding the process by which the utility ranks bids in order to select or "shortlist" the bids with which it will commence negotiations. The renewables bid evaluation process focuses on four primary areas:

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[8] *Id.* at 31.

[9] Resolution E-4216 at 5.

[10] *Id.*

[11] Pub. Util. Code § 399.14(a)(2)(B).

[12] D.04-07-029.

1. Determination of market value of bid;
2. Calculation of transmission adders and integration costs;
3. Evaluation of portfolio fit; and
4. Consideration of non-price factors.

PG&E examined the reasonableness of the 2010-2012 Agreement using the same market value comparison tools used with other RPS transactions received in the 2008 RPS Solicitation and with bilaterals currently being offered to PG&E. The general finding is that this opportunity is competitive with other offers received in the 2008 RPS Solicitation and with other RPS opportunities recently executed or under negotiation. A more detailed discussion of PG&E's evaluation of the 2010-2012 Agreement is provided in Confidential Appendix D.

### 1. Market Valuation

In a "mark-to-market analysis," the present value of the bidder's payment stream is compared with 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. This analysis includes evaluation of the bid price and indirect costs, such as transmission and integration costs. PG&E's analysis of the market value of the 2010-2012 Agreement is addressed in Confidential Appendix D.

### 2. Portfolio Fit

Portfolio fit considers how well an offer's features match PG&E's portfolio needs. As part of the portfolio fit assessment, PG&E differentiates offers by the firmness of their energy delivery and by their energy delivery patterns. A higher portfolio fit measure is assigned to the energy that PG&E is sure to receive and fits the needs of the existing portfolio. Under the 2010-2012 Agreement, PG&E will receive firm deliveries. Also, the Projects will provide RPS-eligible deliveries beginning in 2010, which will directly contribute toward PG&E's RPS goals. Thus, the 2010-2012 Agreement fits PG&E's portfolio in a satisfactory manner.

### 3. Consistency with the Transmission Ranking Cost Decision

The Projects are currently operating under existing interconnection agreements and no upgrades are needed. As noted above, PacifiCorp will deliver firm energy to PG&E at COB. Consequently, no transmission cost adders were used in the evaluation of the Projects.

### 4. Consistent Application of TODs

The price for the power under the 2010-2012 Agreement is not subject to Time of Delivery ("TOD") adjustments.

### 5. Qualitative Factors

PG&E considered qualitative factors including benefits to low income or minority communities, environmental stewardship, local reliability, and resource diversity benefits, as required by D.04-07-029 and D.07-02-011, when evaluating the Projects.

## E. PRG Participation and Feedback

PG&E informed its Procurement Review Group ("PRG") of the transaction on August 14, 2009. PG&E further addresses PRG feedback in Confidential Appendix D.

The PRG for PG&E consists of: California Department of Water Resources, the Commission's Energy Division and Division of Ratepayer Advocates, Union of Concerned Scientists, the Utility Reform Network, the California Utility Employees, and Jan Reid, as a PG&E ratepayer.

## F. RPS Goals

Senate Bill ("SB") 1078 established the California RPS Program, requiring an electrical corporation to increase its use of eligible renewable energy resources to 20 percent of total retail sales no later than December 31, 2017. The legislature subsequently accelerated the RPS goal to reach 20 percent by the end of 2010. In addition, California is actively considering increasing its renewable goals beyond the current 20 percent renewable energy target. Governor Schwarzenegger's Executive Order issued in November 2008 describes a new target for California of 33 percent renewable energy by 2020, and his executive order issued in September 2009 directs the California Air Resources Board to adopt a regulation consistent with this 33 percent target by July 31, 2010. Finally, the California Air Resources Board's Scoping Plan, adopted in December 2008, identifies an increase in the renewables target to 33 percent by 2020 as a key measure for reducing greenhouse gas emissions and meeting California's climate change goals. As discussed above, the 2010-2012 Agreement will contribute to the 20 percent by 2010 RPS goal.

### G. Consistency with Adopted Standard Terms and Conditions

The Commission set forth standard terms and conditions to be incorporated into contracts for the purchase of electricity from eligible renewable energy resources in D.04-06-014, D.07-02-011 as modified by D.07-05-057, and D.07-11-025. These terms and conditions were compiled and published by D.08-04-009. Additionally, the non-modifiable term related to Green Attributes was finalized in D.08-08-028. The non-modifiable terms in the 2010-2012 Agreement 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.

Modifications have been made to the terms in the 2010-2012 Agreement designated as modifiable in D.07-11-025 and D.08-04-009 based upon mutual agreement reached during negotiations. A comparison of the modifiable terms in the 2010-2012 Agreement against the modifiable terms in PG&E's 2009 RPS power purchase agreement form in PG&E's 2009 Solicitation Protocol (as updated on July 10, 2009) are provided in Confidential Appendix H.

Each provision in the 2010-2012 Agreement is essential to the negotiated agreement between the parties, and the Commission should therefore not modify any of the provisions. The Commission should consider the 2010-2012 Agreement as a whole, in terms of its ultimate effect on utility customers. PG&E submits that the 2010-2012 Agreement protects the interests of its customers while achieving the Commission's goal of increasing procurement from eligible renewable resources.

### H. Consistency with Minimum Quantity Decision

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

Although operational, the Projects are considered new facilities for the purposes of the minimum quantity requirement because they began commercial operation on or after

January 1, 2005.[13] The 2010-2012 Agreement therefore counts towards PG&E's contracting obligation under D.07-05-028. PG&E has determined that in 2009, it will be in compliance with the minimum quantity requirement set forth in D.07-05-028.

### I. Compliance with the Interim Emissions Performance Standard

In D.07-01-039, the Commission adopted an Emissions Performance Standard ("EPS") that applies to contracts for a term of five or more years for baseload generation with an annualized plant capacity factor of at least 60 percent. The 2010-2012 Agreement is not subject to the EPS because it involves a short-term contract with a term of less than five years.

Notification of compliance with D.07-01-039 is provided through this Advice Letter, which has been served on the service list in the RPS rulemaking, R.08-08-009.

### J. MPR and AMFs

The actual price under the 2010-2012 Agreement is confidential, market sensitive information. As the 2010-2012 Agreement was a result of bilateral negotiations, the 2010-2012 Agreement is not eligible for AMFs. There is currently no short-term MPR, but the contract pricing under the 2010-2012 Agreement generally compares favorably to the 10-year 2008 MPR adopted in Resolution E-4214 on December 18, 2008.

## III. PROJECT DEVELOPMENT STATUS

### A. Site Control

The Projects have full site control and are operational.

### B. Resource and/or Availability of Fuel

The Projects are existing wind facilities with no other fuel requirements.

### C. Transmission

The Projects are operational and no additional transmission issues are expected.

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[13] *See* D.07-05-028 at 33, Ordering Paragraph 1 (defining existing facilities as those that began commercial operation before January 1, 2005, and defining new facilities as those that began commercial operation on or after January 1, 2005).

### D. Technology Type and Level of Technology Maturity

The Projects use wind turbine generators that have been operating since the facilities began delivering power after 2005.

### E. Permitting

The Projects are fully permitted.

### F. Developer Experience

PacifiCorp has demonstrated its ability to successfully build and operate wind facilities and has brought into operation about six existing wind facilities since 2006. PacifiCorp currently operates ten wind facilities, including four purchased from other developers.

### G. Financing Plan

The Projects are operational.

### H. Production Tax Credit/Investment Tax Credit

The terms of the 2010-2012 Agreement are independent of whether the Projects are receiving Production Tax Credits.

### I. Equipment Procurement

The Projects are fully operational and equipment procurement is complete.

## IV. CONTINGENCIES AND PROJECT MILESTONES

The Projects are operational. Contingencies and project milestones are therefore not applicable.

## V. REGULATORY PROCESS

### A. Requested Effective Date

PG&E requests that the Commission issue a resolution approving this advice filing no later than **November 20, 2009**. Justification for this date is provided in Confidential Appendix D.

### B. Earmarking

PG&E reserves the right to earmark this contract.

### C. RPS-Eligibility Certification

The 2010-2012 Agreement includes the non-modifiable representation and warranty that during the delivery period, the Projects will constitute eligible renewable energy resources certified by the CEC. As noted above, seven of the eight Projects have received CEC certification, and certification for the eighth Project is pending.

### D. Request for Confidential Treatment

In support of this Advice Letter, PG&E has provided the following confidential information, including the 2010-2012 Agreement and other information that more specifically describes the rights and obligations of the parties. This information is being submitted in the manner directed by 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. A separate Declaration Seeking Confidential Treatment is being filed concurrently with this Advice Letter.

Additionally, as the Projects are operating wind facilities, there is no viability uncertainty associated with these facilities. As a result, Confidential Appendix E – Project Viability has not been provided, as noted below in the list of Confidential Attachments.

**<u>Confidential Attachments:</u>**

**Appendix A – Overview of 2004 – 2008 Solicitation Bids**

**Appendix B – 2008 Bid Evaluations**

**Appendix C – Independent Evaluator Report (Confidential)**

**Appendix D – Contract Terms and Conditions Explained**

**Appendix E – Project Viability – Intentionally Omitted as Projects are fully operational**

**Appendix F – Projects' Contribution Toward RPS Goals**

**Appendix G – Confirmation Agreement**

**Appendix H – Standard Terms and Conditions Comparison – Modifiables**

**Public Attachments:**

**Appendix I – Independent Evaluator Report (Public)**

**Appendix J - EEI Master Agreement**

## VI. REQUEST FOR COMMISSION APPROVAL

The continued effectiveness of the 2010-2012 Agreement is conditioned on the occurrence of "CPUC Approval," as that term is defined in the 2010-2012 Agreement.

Therefore, PG&E requests that the Commission issue a resolution no later than **November 20, 2009** that:

1. Approves the 2010-2012 Agreement in its entirety, including payments to be made by PG&E pursuant to the 2010-2012 Agreement, subject to the Commission's review of PG&E's administration of the 2010-2012 Agreement.

2. Finds that any procurement pursuant to the 2010-2012 Agreement is procurement from an eligible renewable energy resource 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.), D.03-06-071 and D.06-10-050, or other applicable law.

3. Finds that all procurement and administrative costs, as provided by Public Utilities Code section 399.14(g), associated with the 2010-2012 Agreement shall be recovered in rates.

4. Adopts the following finding of fact and conclusion of law in support of CPUC Approval:

    a. The 2010-2012 Agreement is consistent with PG&E's 2008 RPS procurement plan.

b. The terms of the 2010-2012 Agreement, including the price of delivered energy, are reasonable.

5. Adopts the following finding of fact and conclusion of law in support of cost recovery for the 2010-2012 Agreement:

    a. The utility's costs under the 2010-2012 Agreement shall be recovered through PG&E's Energy Resource Recovery Account.

    b. Any stranded costs that may arise from the 2010-2012 Agreement are subject to the provisions of D.04-12-048 that 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.

6. Adopts the following finding with respect to resource compliance with the EPS adopted in R.06-04-009:

    a. The 2010-2012 Agreement is not a long-term financial commitment subject to the EPS under Public Utilities Code section 8340(j) because its term of contract is less than five years.

**Protests:**

Anyone wishing to protest this filing may do so by sending a letter by **October 8, 2009,** which is **20** days from the date of this filing. The protest must state the grounds upon which it is based, including such items as financial and service impact, and should be submitted expeditiously. Protests should be mailed to:

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

Facsimile: (415) 703-2200
E-mail: mas@cpuc.ca.gov and jnj@cpuc.ca.gov

Copies should also be mailed to the attention of the Director, Energy Division, Room 4005 and Honesto Gatchalian, Energy Division, at the address shown above.

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

Pacific Gas and Electric Company
Attention: Brian Cherry
Vice President, Regulatory Relations
77 Beale Street, Mail Code B10C
P.O. Box 770000
San Francisco, California 94177

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

**Effective Date:**

PG&E requests that the Commission issue a resolution approving this advice filing no later than **November 20, 2009**.

**Notice:**

In accordance with General Order 96-B, Section IV, a copy of this Advice Letter excluding the confidential appendices is being sent electronically and via U.S. mail to parties shown on the attached list and the service lists for R.08-08-009, R.06-02-012, and R.08-02-007. Non-market participants who are members of PG&E's Procurement Review Group and have signed appropriate Non-Disclosure Certificates will also receive the Advice Letter and accompanying confidential attachments by overnight mail. Address changes should be directed to San Heng (415) 973-2640. Advice letter filings can also be accessed electronically at: http://www.pge.com/tariffs.

Brian K. Cherry (sc)

Brian K. Cherry
Vice President - Regulatory Relations

cc: Service List for R.08-08-009
Service List for R.08-02-007
Service List for R.06-02-012
Paul Douglas – Energy Division
Sean Simon – Energy Division

Attachments

**Limited Access to Confidential Material:**

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

**Confidential Attachments:**

**Appendix A – Overview of 2004 – 2008 Solicitation Bids**

**Appendix B – 2008 Bid Evaluations**

**Appendix C – Independent Evaluator Report (Public Version)**

**Appendix D – Contract Terms and Conditions Explained**

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**Appendix F – Projects' Contribution Toward RPS Goals**

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**Public Attachments:**

**Appendix I – Independent Evaluator Report (Public)**

**Appendix J - EEI Master Agreement**

# CALIFORNIA PUBLIC UTILITIES COMMISSION

ADVICE LETTER FILING SUMMARY
ENERGY UTILITY

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

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

| | |
|---|---|
| Utility type:<br>☑ ELC ☑ GAS<br>☐ PLC ☐ HEAT ☐ WATER | Contact Person: David Poster and Sally Cuaresma<br>Phone #: (415) 973-1082; (415) 973-5012<br>E-mail: DXPU@pge.com; A2C7@pge.com |
| EXPLANATION OF UTILITY TYPE<br>ELC = Electric GAS = Gas ☐<br>PLC = Pipeline HEAT = Heat WATER = Water | (Date Filed/ Received Stamp by CPUC) |

Advice Letter (AL) #: **3527-E** **Tier:** [**3**]

Subject of AL: **Contract for Procurement of Renewable Energy Resources Resulting from PG&E's Wind Energy Purchase Agreement with PacifiCorp**

Keywords (choose from CPUC listing): Contracts; Agreements

AL filing type: ☐ Monthly ☐ Quarterly ☐ Annual ☑ One-Time ☐ Other ____________

If AL filed in compliance with a Commission order, indicate relevant Decision/Resolution #: Does AL replace a withdrawn or rejected AL? If so, identify the prior AL: No

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

Is AL requesting confidential treatment? If so, what information is the utility seeking confidential treatment for: Yes. See the attached matrix that identifies all of the confidential information.

Confidential information will be made available to those who have executed a nondisclosure agreement: All members of PG&E's Procurement Review Group who have signed nondisclosure agreement will receive the confidential information.

Name(s) and contact information of the person(s) who will provide the nondisclosure agreement and access to the confidential information: Richard Miram, (415) 973-1170

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Resolution Required? ☑ Yes ☐No

Requested effective date: **November 20, 2009** No. of tariff sheets: N/A

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

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

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

Tariff schedules affected:

Service affected and changes proposed:

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

**CPUC, Energy Division**
**Tariff Files, Room 4005**
**DMS Branch**
**505 Van Ness Ave., San Francisco, CA 94102**
**jnj@cpuc.ca.gov and mas@cpuc.ca.gov**

**Pacific Gas and Electric Company**
**Attn: Brian K. Cherry, Vice President, Regulatory Relations**
**77 Beale Street, Mail Code B10C**
**P.O. Box 770000**
**San Francisco, CA 94177**
**E-mail: PGETariffs@pge.com**

**DECLARATION OF RICH MIRAM**
**SEEKING CONFIDENTIAL TREATMENT**
**FOR CERTAIN DATA AND INFORMATION CONTAINED IN ADVICE LETTER 3527-E**
**(PACIFIC GAS AND ELECTRIC COMPANY - U 39 E)**

I, Rich Miram declare:

1. I am presently employed by Pacific Gas and Electric Company ("PG&E") and have been an employee at PG&E since 1973. My current title is Principal within PG&E's Energy Procurement organization. In this position, my responsibilities include negotiating power purchase agreements with counterparties in the business of producing electric energy. In carrying out these responsibilities, I have acquired knowledge of PG&E's contracts with numerous counterparties and have also gained knowledge of the operations of electricity sellers in general. Through this experience, I have become familiar with the type of information that would affect the negotiating positions of electricity sellers with respect to price and other terms, as well as with the type of information that such sellers consider confidential and proprietary.

2. Based on my knowledge and experience, and in accordance with Decision ("D.") 08-04-023 and the August 22, 2006 "Administrative Law Judge's Ruling Clarifying Interim Procedures for Complying with Decision 06-06-066," I make this declaration seeking confidential treatment of Appendices A, B, C, D, F, G, and H to Advice Letter 3527-E submitted on September 17, 2009. By this Advice Letter, PG&E is seeking this Commission's approval of a wind energy purchase agreement that PG&E has executed with PacifiCorp.

3. Attached to this declaration is a matrix identifying the data and information for which PG&E is seeking confidential treatment. The matrix specifies that the material PG&E is seeking to protect constitutes the particular type of data and information listed in Appendix 1 of D. 06-06-066 and Appendix C of D. 08-04-023 ("the IOU Matrix"), or constitutes information

that should be protected under General Order 66-C. The matrix also specifies the category or categories in the IOU Matrix to which the data and information corresponds (where applicable), and why confidential protection is justified. Finally, the matrix specifies: (1) that PG&E is complying with the limitations specified in the IOU Matrix for that type of data or information (where applicable); (2) that the information is not already public; and (3) that the data cannot be aggregated, redacted, summarized or otherwise protected in a way that allows partial disclosure. By this reference, I am incorporating into this declaration all of the text in the attached matrix that is pertinent to this filing.

I declare under penalty of perjury, under the laws of the State of California that, to the best of my knowledge, the foregoing is true and correct. Executed on September 17, 2009 at San Francisco, California.

Rich Miram

PACIFIC GAS AND ELECTRIC COMPANY
Advice Letter 3527-E
September 17, 2009

IDENTIFICATION OF CONFIDENTIAL INFORMATION PER DECISION 06-06-066 AND DECISION 08-04-023

| | Redaction Reference | 1) The material submitted constitutes a particular type of data listed in the Matrix, appended as Appendix 1 to D.06-06-066 and Appendix C to D.08-04-023 (Y/N) | 2) Which category or categories in the Matrix the data correspond to: | 3) That it is complying with the limitations on confidentiality specified in the Matrix for that type of data (Y/N) | 4) That the information is not already public (Y/N) | 5) The data cannot be aggregated, redacted, summarized, masked or otherwise protected in a way that allows partial disclosure (Y/N) | PG&E's Justification for Confidential Treatment | Length of Time |
|---|---|---|---|---|---|---|---|---|
| 1 | Document: Advice Letter 3527-E | | | | | | | |
| 2 | Appendix A | Y | Item VIII A) Bid information and B) Specific quantitative analysis involved in scoring and evaluation of participating bids. | Y | Y | Y | This Appendix contains bid information and bid evaluations from the 2004, 2005, 2006, 2007 and 2008 solicitations. This information would provide market sensitive information to competitors and is therefore considered confidential. Furthermore, offers from the 2005, 2006, 2007, and 2008 solicitations and offers received outside of those solicitations are still under negotiation, further substantiating why releasing this information would be damaging to the negotiation process. | For information covered under Item VIII A), remain confidential until after final contracts submitted to CPUC for approval<br><br>For information covered under Item VIII B), remain confidential for three years after winning bidders selected |
| 3 | Appendix B | Y | Item VIII A) Bid information and B) Specific quantitative analysis involved in scoring and evaluation of participating bids. | Y | Y | Y | This Appendix contains bid information and bid evaluations from the2008 solicitation. This information would provide market sensitive information to competitors and is therefore considered confidential. Furthermore, offers from the 2005, 2006, 2007, and 2008 solicitations and offers received outside of those solicitations are still under negotiation, further substantiating why releasing this information would be damaging to the negotiation process. | For information covered under Item VIII A), remain confidential until after final contracts submitted to CPUC for approval<br><br>For information covered under Item VIII B), remain confidential for three years after winning bidders selected |

| | Redaction Reference | 1) The material submitted constitutes a particular type of data listed in the Matrix, appended as Appendix 1 to D.06-06-066 and Appendix C to D.08-04-023 (Y/N) | 2) Which category or categories in the Matrix the data correspond to: | 3) That it is complying with the limitations on confidentiality specified in the Matrix for that type of data (Y/N) | 4) That the information is not already public (Y/N) | 5) The data cannot be aggregated, redacted, summarized, masked or otherwise protected in a way that allows partial disclosure (Y/N) | PG&E's Justification for Confidential Treatment | Length of Time |
|---|---|---|---|---|---|---|---|---|
| 4 | Appendix C | Y | Item VIII A) Bid information and B) Specific quantitative analysis involved in scoring and evaluation of participating bids. Item VII G ) Renewable Resource Contracts under RPS program - Contracts without SEPs. Item VII (un-numbered category following VII G) Score sheets, analyses, evaluations of proposed RPS projects. General Order 66-C. | Y | Y | Y | This Appendix contains bid information and bid evaluations from the 2008 solicitation, discusses, analyzes and evaluates the Projects and the terms of the confirmation to the Edison Electric Institute ("EEI") master power purchase and sale agreement between PacifiCorp and PG&E ("Confirmation"), and contains confidential information of the counterparty. Disclosure of this information would provide valuable market sensitive information to competitors. Since negotiations are still in progress with bidders from the 2005, 2006, 2007, and 2008 solicitations and with other counterparties, this information should remain confidential. Release of this information would be damaging to negotiations. Furthermore, the counterparty to the Confirmation has an expectation that the terms of the Confirmation will remain confidential pursuant to confidentiality provisions in the EEI master power purchase and sale agreement. I am informed and believe that General Order 66-C provides a basis for confidential treatment. General Order 66-C includes in its category of records not open to public inspection "Information obtained in confidence from other than a business regulated by this Commission where the against the public interest." (Paragraph 2.8). It is in the public interest to treat such information as confidential because if such information were made public, it would put the counterparty at a business disadvantage, could create a disincentive to do business with PG&E and other regulated utilities, and could have a damaging effect on current and future negotiations with other counterparties. | For information covered under Item VIII A), remain confidential until after final contracts submitted to CPUC for approval<br><br>For information covered under Item VIII B), remain confidential for three years after winning bidders selected<br><br>For information covered under Item VII G) and Item VII (un-numbered category following VII G), remain confidential for three years after the commercial operation date<br><br>For information covered by General Order 66-C, remain confidential |
| 4 | Appendix D | Y | Item VII G) Renewable Resource Contracts under RPS program - Contracts without SEPs. Item VII (un-numbered category following VII G) Score sheets, analyses, evaluations of proposed RPS projects. General Order 66-C. | Y | Y | Y | This Appendix discusses, analyzes and evaluates the Projects and the terms of the Confirmation. Disclosure of this information would provide valuable market sensitive information to competitors. Since negotiations are still in progress with bidders from the 2005, 2006, 2007, and 2008 solicitations and with other counterparties, this information should remain confidential. Release of this information would be damaging to negotiations. Furthermore, the counterparty to the Confirmation has an expectation that the terms of the Confirmation will remain confidential pursuant to confidentiality provisions in the EEI master power purchase and sale agreement. I am informed and believe that General Order 66-C provides a basis for confidential treatment. General Order 66-C includes in its category of records not open to public inspection "Information obtained in confidence from other than a business regulated by this Commission where the disclosure would be against the public interest." (Paragraph 2.8). It is in the public interest to treat such information as confidential because if such information were made public, it would put the counterparty at a business disadvantage, could create a disincentive to do business with PG&E and other regulated utilities, and cc current and future negotiations with other counterparties. | For information covered under Item VII G) and Item VII (un-numbered category following VII G), remain confidential for three years after the commercial operation date<br><br>For information covered by General Order 66-C, remain confidential |
| 5 | Appendix F | Y | Item VII (un-numbered category following VII G) Score sheets, analyses, evaluations of proposed RPS projects. Item VI B) Utility Bundled Net Open Position for Energy (MWh). | Y | Y | Y | This Appendix contains information that, if disclosed, would provide valuable market sensitive information to competitors and allow them to see PG&E's remaining RPS net open energy position. Since negotiations are still in progress with bidders from the 2005, 2006, 2007, and 2008 solicitations and with other counterparties, this information should remain confidential for three years. | Remain confidential for three years |

| | Redaction Reference | 1) The material submitted constitutes a particular type of data listed in the Matrix, appended as Appendix 1 to D.06-06-066 and Appendix C to D.08-04-023 (Y/N) | 2) Which category or categories in the Matrix the data correspond to: | 3) That it is complying with the limitations on confidentiality specified in the Matrix for that type of data (Y/N) | 4) That the information is not already public (Y/N) | 5) The data cannot be aggregated, redacted, summarized, masked or otherwise protected in a way that allows partial disclosure (Y/N) | PG&E's Justification for Confidential Treatment | Length of Time |
|---|---|---|---|---|---|---|---|---|
| 6 | Appendix G | Y | Item VII G) Renewable Resource Contracts under RPS program - Contracts without SEPs. | Y | Y | Y | This Appendix contains the Confirmation. Disclosure of the Confirmation would provide valuable market sensitive information to competitors. Since negotiations are still in progress with bidders from the 2005, 2006, 2007 and 2008 solicitations and with other counterparties, this information should remain confidential. Release of this information would be damaging to negotiations. Furthermore, the counterparty to the Confirmation has an expectation that the terms of the Confirmation will remain confidential pursuant to confidentiality provisions in the EEI master power purchase and sale agreement. | Remain confidential for three years after the commercial operation date |
| 7 | Appendix H | Y | Item VII G) Renewable Resource Contracts under RPS program - Contracts without SEPs. | Y | Y | Y | This Appendix contains certain terms of the Confirmation. Disclosure of certain terms of the Confirmation would provide valuable market sensitive information to competitors. Since negotiations are still in progress with bidders from the 2005, 2006, 2007 and 2008 solicitations and with other counterparties, this information should remain confidential. Release of this information would be damaging to negotiations. Furthermore, the counterparty to the Confirmation has an expectation that the terms of the Confirmation will remain confidential pursuant to confidentiality provisions in the EEI master power purchase and sale agreement. | Remain confidential for three years after the commercial operation date |

# Appendix I

# Public Independent Evaluator Report

ARROYO SECO CONSULTING

# PACIFIC GAS AND ELECTRIC COMPANY BILATERAL CONTRACT EVALUATION

## ADVICE LETTER REPORT OF THE INDEPENDENT EVALUATOR ON THE PROPOSED CONTRACT WITH PACIFICORP FOR A VERY SHORT-TERM TRANSACTION FOR 2010 - 2012

SEPTEMBER 17, 2009

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# 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 very short-term Power Purchase Agreement (PPA) with PacifiCorp to procure renewable energy from PacifiCorp's portfolio of wind generation facilities in Wyoming, Idaho, and Washington State, including eligible renewable resources. An independent evaluator (IE), Arroyo Seco Consulting (Arroyo), conducted activities to review and assess PG&E's processes as the utility negotiated this PPA.

The structure of this report follows the 2008 Independent Evaluator Report Template provided by the Energy Division of the California Public Utilities Commission (CPUC). Topics covered include:

- The role of the IE;
- 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;
- Adequacy of outreach and robustness of the prior competitive solicitation;
- Fairness of project-specific negotiations; and
- Merit of the PPA for CPUC approval.

An independent review raised no major concerns about the fairness of the methodology used in evaluating the 2010-2012 PacifiCorp contract or how it was administered. Also, Arroyo has identified no major issues with the fairness of the negotiations or the reasonableness of the terms of the PPA. Arroyo agrees with PG&E that the 2010-2012 contract with PacifiCorp merits approval, based on the high project viability of the facilities.

# 1. ROLE OF THE INDEPENDENT EVALUATOR

This chapter elaborates on the basis for the participation of an Independent Evaluator in the review of very short-term[1] bilateral contracts for renewable energy, describes the role of the IE, and details oversight activities performed by the IE on this transaction.

## 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 its Decision 04-12-048 on December 16, 2004 (Findings of Fact 94-95, Ordering Paragraph 28). In that Decision, which addressed the approval of three utilities' long-term procurement plans, the CPUC required the 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 use of an IE would serve as a safeguard in the process of evaluating IOU-built or IOU-affiliated projects competing against PPAs with independent developers, a safeguard to protect consumers from any anti-competitive conduct between utilities and their corporate affiliates or from anti-competitive conduct by utilities developing their own generation.

Later, in approving the IOUs' 2006 Renewables Portfolio Standard (RPS) procurement plans and solicitation protocols, the CPUC issued Decision 06-05-039 on May 25, 2006. In that Decision, the CPUC expanded its requirement, ordering that each IOU use an IE to evaluate and report on the entire solicitation, evaluation, and selection process, for the 2006 RPS Request for Offers (RFO) and all future competitive solicitations. 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 articulated principles to apply to the evaluation of short-term contracts for renewable power, and concluded that, "For moderately short-term contracts, the full IE report should be supplied…these IE requirements apply equally to all very short-term and moderately short-term contracts, whether through a solicitation or bilaterally negotiated."[2] For very-short-term bilateral contracts for which the utility seeks "fast-track approval", the decision authorizes the use of the short-form IE template, but the PacifiCorp 2010-2012 transaction does not fall into that category.

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1 "Very short-term contracts" are defined by the CPUC as contracts with a term of one to 48 months. The contract with PacifiCorp for the three years of calendar 2010 through 2012 (excluding the third quarter of each year) falls into this range.

2 CPUC Decision 09-06-050, June 19, 2009, "Decision Establishing Price Benchmarks and Contract Review Processes for Short-Term and Bilateral Procurement Contracts for Compliance with the California Renewables Portfolio Standard", page 25

## B. KEY INDEPENDENT EVALUATOR ROLES

To comply with the requirements ordered by the CPUC in Decision 09-06-050, PG&E retained Arroyo Seco Consulting to serve as IE for the very short-term bilateral contract that was being negotiated between PG&E and PacifiCorp.

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."[3] More specifically, the Energy Division (ED) of the CPUC has provided a template to guide how IEs should report on the 2008 RPS competitive procurement process, outlining five specific issues that should be addressed:

- Was the IOU's methodology for RPS bid evaluation and selection designed fairly?
- Was the IOU's RPS bid evaluation and selection process fairly administered?
- Did the IOU do adequate outreach to potential bidders, and did its outreach activities result in an adequately robust solicitation to promote competition? (This aspect of the IE role does not apply directly to the PacifiCorp transaction, which resulted from bilateral discussions rather than a public solicitation.)
- Were project-specific negotiations fair?
- Does the proposed contract merit CPUC approval?

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

## C. IE OVERSIGHT ACTIVITIES

To fulfill the role of evaluating and providing oversight to the process of developing the 2010-2012 PacifiCorp PPA, several tasks were undertaken. Arroyo Seco had performed several of these tasks within its work scope of serving as IE for PG&E's 2008 and 2009 RPS competitive solicitations; these prior activities were directly relevant to the evaluation of the 2010-2012 PacifiCorp PPA.

- Reviewing the 2008 RPS RFO Solicitation Protocol and its various attachments including the Forms of Power Purchase Agreement and PG&E's detailed LCBF evaluation criteria;

- Examining the confidential protocols detailing how PG&E evaluates PPAs against various criteria, including market valuation, portfolio fit, transmission adders, credit, project viability, and RPS goals. These nonpublic internal

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

protocols were evaluated to test whether they were consistent with the approved public Solicitation Protocol and whether the procedures, inputs, parameters, and standards were fair and reasonable'

- Examining PG&E's RFO master contact list; performing a detailed analysis of contacts added in 2008 with respect to industry and technology representation;

- Interviewing members of PG&E's evaluation committee and evaluation sub-committees regarding the process, data inputs and parameters, background industry and utility information, quantitative models, and other considerations taken into account in evaluating PPAs against non-quantitative criteria and in performing market valuation of PPAs;

- Interviewing PG&E middle-office staff regarding the internal review process that serves as a check on market valuation modeling and its inputs;

- Reviewing in detail various data inputs and parameters used in PG&E's market valuation methodology;

- Spot-checking offer-specific data inputs to PG&E's valuation model;

- Developing a simple but independent market valuation model for the purpose of checking results from PG&E's LCBF methodology;

- Providing independent advice and suggestions to the PG&E team as needed, such as input on contract size issues and possible inclusion of non-shortlisted parties;

- Participating in meetings of PG&E's Procurement Review Group in which short-listed offers from the 2008 RPS RFO or specific bilaterally negotiated contracts were discussed.

Because the final CPUC decision requiring utilities to engage an Independent Evaluator for oversight of and reporting about long-term bilateral contracts was not issued until June 19, 2009, a point in time at which PG&E was already in discussions with PacifiCorp, Arroyo Seco Consulting did not participate directly in or observe discussions between the two parties, as would ordinarily be the case for the IE role in a negotiation following a competitive solicitation. The findings of this report regarding the fairness of negotiations are based indirectly instead on (1) routinely scheduled debriefings with the key PG&E transactor negotiating the contract, (2) review of the paper trail of contract agreement mark-ups that reveal negotiating issues between the parties, (3) a review of detailed final contract terms and conditions of the 2010-2012 PacifiCorp transaction and comparison of these to those of other PPAs, executed or under negotiation, from the 2008 RPS RFO or from recent bilateral negotiations, and (4) a comparison of detailed final contract terms of the transaction to the terms of PG&E's 2009 Form Agreement (as adapted for short-term contracts) that would have served as the starting point for negotiations if the PacifiCorp transaction had originated in a competitive solicitation. Arroyo's opinions provided in this report are not based directly on actual observation over time of the bilateral negotiations and any possible concessions granted within them.

## D. TREATMENT OF CONFIDENTIAL INFORMATION

The CPUC's Decision 06-06-066, issued on June 29, 2006, detailed specific guidelines for the treatment of information as confidential vs. non-confidential in the context of IOU electricity procurement and related activities, including renewable power contracts that result from bilateral negotiations rather than competitive solicitations. For example, the Decision provides for confidential treatment of "Score sheets, analyses, evaluations of proposed RPS projects",[4] as opposed to public treatment (after submittal of final contracts for CPUC approval) of the total number of projects and megawatts bid by resource type.

[4]"Interim Opinion Implementing Senate Bill No. 1488, Relating to Confidentiality of Electric Procurement Data Submitted to the Commission", June 29, 2006, Appendix 1, page 17

# 2. FAIRNESS OF THE DESIGN OF PG&E'S LEAST-COST, BEST-FIT METHODOLOGY

The key finding of this chapter is that, based on IE oversight activities and findings, PG&E's evaluation methodology was designed fairly.

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

## A. PRINCIPLES FOR EVALUATING THE METHODOLOGY

The Energy Division of the CPUC has usefully provided a set of principles for evaluating the process used by IOUs for selecting Offers in competitive solicitations, within the template intended for use by IEs in reporting. This list was previously developed by Jonathan Jacobs of PA Consulting, serving as IE for San Diego Gas & Electric Company (SDG&E).

Mr. Jacobs' principles include:

- The procurement target should be large enough to ensure that the utility has a reasonable chance of meeting its 20% RPS target (taking into account potential contract failures).
- The IOU evaluation should only be based on those criteria requested in the response form. There should be no consideration of any information that might indicate whether the bidder is an affiliate.
- The methodology should identify how quantitative measures will be considered and be consistent with an overall metric.
- There should be no differences in the evaluation method for different technologies that cannot be explained in a technology-neutral manner.
- The methodology does not have to be the one that the IE would independently have selected but it needs to be 'reasonable'.

Some additional considerations appear relevant to the specific situation PG&E finds itself in. PG&E streamlined its evaluation process after the 2007 RPS RFO by dropping its prior approach of "partial ordering." Instead, the team ranks Offers by market value, after which, using "the information and scores from the other evaluation criteria, PG&E will then apply judgment and PRG feedback to decide which Offers to include or not include on the shortlist."[5] The application of judgment in bringing the non-valuation criteria to bear on decision-making, rather than a rigorously mathematical, 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 qualitative measures will be considered; non-valuation criteria used in evaluating contracts should be clear to counterparties.
- The logic of using non-valuation criteria to reject high-value contracts and select low-value contracts should be applied consistently and without bias.
- The valuation methodology should be reasonably consistent with industry practices.

## B. DESCRIPTION OF PG&E'S METHODOLOGY

PG&E's approach is to assess a proposed contract using a handful of criteria specified by CPUC decisions. PG&E has provided a public version of the description of its methodology in Attachment K to the Solicitation Protocol of its 2009 RPS RFO, most recently revised on August 17, 2009.[6]

Market Valuation. PG&E measures market value as benefits minus costs. Benefits include energy value and capacity value (resource adequacy value); ancillary services value is assumed zero. Costs are PG&E's payments to the counterparty. Costs are adjusted to reflect transmission adders as described below. The costs of integrating an intermittent resource into the electric system, such as load-following and regulation, are assumed to be zero. Both benefits and costs are discounted from the entire contract period to 2010 dollars per MWh in the methodology.

For as-available energy delivery, 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 proposed generation profile. This forward curve is constructed by PG&E staff using market data and extrapolation assumptions. For baseload and peaking resources the volume of energy deliveries are based on the performance requirements of the contract. If appropriate, the contract prices are adjusted by time-of-delivery factors. If the power plant emits greenhouse gases (e.g. a hybrid natural gas-solar thermal generator), a greenhouse gas adder is included in costs based on PG&E's assumptions.

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[5] "2008 Renewable Energy Procurement Plan and Draft Solicitation Protocol of Pacific Gas and Electric Company", August 1, 2007, CPUC Rulemaking 06-05-027, page 2

[6] "PG&E's Description of its RPS Bid Evaluation, Selection Process and Criteria", posted on website http://www.pge.com/includes/docs/word_xls/b2b/wholesaleelectricsuppliersolicitation/Attachment_K_LCBF_Eval_Criteria081809.doc

PG&E projects capacity value as a nominal dollar per kilowatt-year estimate. For as-available products, capacity quantity is calculated based on the projected generation profile and the approach set forth in CPUC Decision 09-06-028.[7] Capacity benefit is calculated as the product of capacity value and an estimate of net qualifying capacity, and discounted to 2010 nominal dollars. In the case of generation resources that are located so as to support PG&E's Local Capacity Requirement as specified by the California ISO, a premium is assigned to capacity value.

PG&E employs other analytic techniques using real options valuation to assign values to dispatchable resources and to those which provide the utility with a buyout option. These do not apply to the PacifCorp contract, which is a structured energy sale without dispatch rights or asset purchase options.

Portfolio Fit. PG&E assesses the fit of a new resource with its generation portfolio by reviewing the resource's delivery characteristics in terms of firmness and time of delivery. The latter includes a view of the resource's profile in time of day as well as seasonality. In the 2009 RPS solicitation, PG&E proposes to use a numerical score to rate the portfolio fit of offers; however, this scoring approach is not currently applied to bilaterally negotiated contracts.

Credit and Collateral. PG&E has a standing set of policies, articulated in its standard Form Agreement that set requirements for counterparties to post collateral at the various phases of project development of new generators in order to help secure protection for ratepayers, including

- Offer deposit, submitted with an offer in the case of developers participating in a competitive solicitation (note that this is not required for offers with a term less than five years from existing resources, as is the case with the PacifiCorp transaction);

- Project development security, posted after execution of an agreement; in the case of existing resources, pre-delivery term security is posted according to the standard 2009 Form Agreement;

- Post effective date project development security, posted after the agreement becomes effective, e.g. upon CPUC approval; and

- Delivery term security, posted upon commencement of commercial operation and continuing during the actual period when power is delivered.

PG&E evaluates the counterparty's agreement to provide collateral at the levels required. Also, PG&E may evaluate the counterparty's credit quality and consider the degree to which

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[7] California Public Utilities Commission, "Decision Adopting Local Procurement Obligations for 2010 and Further Refining the Resource Adequacy Program", June 22, 2009. Note that the PG&E team must make assumptions to convert a projected average generation profile into a 70% exceedance level as prescribed by the Decision; this is described in the most recent revision of Attachment K to PG&E's 2009 RPS RFO Solicitation Protocol.

counterparty risk may become excessively concentrated with a few suppliers. While offers in PG&E's competitive RPS solicitations receive a numerical score for Credit, the contracts that are bilaterally negotiated do not receive this level of formal review. However, considerations of credit and collateral enter into PG&E's internal decisions about such bilateral contracts.

Project Viability. PG&E will employ its own modified version of the CPUC's Project Viability Calculator (PVC) to evaluate offers received in the 2009 competitive RPS solicitation. For contracts arrived at through bilateral negotiations, PG&E has not yet required the use of the PVC. The modified calculator, described in Attachment K of the 2009 RPS RFO solicitation protocol, scores the project against twelve criteria within 3 major categories of Company/Development Team, Technology, and Development Milestones. PG&E's modification was to include a criterion of EPC Experience within the Company/Development Team category, rating the experience the developer has had with its engineering, procurement, and construction contractor and the experience that the contractor has had with the project's technology. PG&E reweighted the various criteria having added this new criterion. While the Calculator could be used to evaluate existing projects such as the wind facilities in PacifiCorp's portfolio, many of the criteria appropriate for evaluating proposed new generation facilities are irrelevant for use in scoring existing plants.

In the prior 2008 RPS solicitation, PG&E had used a numerical scoring system that preceded development of the Project Viability Calculator. This system assigned scores to individual attributes of offered projects such as technical viability and site control. As with the PVC, this system was more appropriate for evaluating proposed new facilities than existing, operating projects such as the PacifiCorp wind facilities.

RPS Goals. PG&E rates Offers in competitive solicitations based on specific observations about how the proposed project or transaction would contribute to California's RPS goals, including

- Non-quantitative factors identified in CPUC Decision 04-07-029;
- Legislative findings and benefits about the impact of increasing the use of renewable energy;
- Consistency with the CPUC's Water Action Plan;
- Support for the Governor's objectives outlined in Executive Order S-06-06 regarding the use of biomass-based energy; and
- Support for PG&E's goals for supplier diversity.

While the offers for competitive RPS solicitations receive a numerical score for the RPS Goals criterion, the formal process of scoring is not employed for bilaterally negotiated contracts, though these sorts of attributes are typically discussed internally when PG&E makes management decisions about bilateral contracts.

Transmission Adders. When evaluating offers from competitive RPS solicitations, PG&E takes into account the expected impact of new generation on the cost of transmission network upgrades by calculating a transmission cost adder applied to the cost of the resource. The adder is based on the lesser of an estimate of upgrade cost drawn from the appropriate utility's Transmission Ranking Cost Report, or an estimate of alternative commercial arrangements for managing the power through such transactions as remarketing and utility swaps. PG&E does not employ the transmission cost adder when evaluating bilaterally negotiated contracts, so this component of its LCBF methodology does not apply to the 2010-12 PacifiCorp transaction.

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

PG&E's evaluation methodology has been revised over the course of several years, and its evolution has benefitted from input from various IEs, the Energy Division, and the utility's Procurement Review Group ("PRG"). Consequently, it has achieved a certain degree of refinement that has strengthened the process from the perspective of fairness and reasonableness.

At a high level, PG&E's methodology has several strengths, particularly when compared to approaches employed by many utilities in other jurisdictions:

- Use of an IE and the PRG for oversight and review, and their particular focus on evaluation of utility-affiliate offers, utility-owned generation, Power Purchase and Sale Agreements, and buyout options, allow for more transparent consideration of the fairness of how affiliate or utility-owned generation is treated vs. independent developers. The lack of such safeguards against anti-competitive behavior in some jurisdictions is strikingly different.

- PG&E's approach allows it to emphasize key non-valuation criteria that have particular current importance, such as project viability, in contrast to a rigid weighting system for price and non-price criteria as employed by other utilities.

- The public issuance of PG&E's evaluation protocols, and the transparency and detail provided to potential counterparties about how, specifically, PPAs will be evaluated, gives renewable power developers clearer and more detailed guidance than typical utility industry practice.

- The methodology does not explicitly incorporate a bias for or against any individual technology per se, but compares the valuation of possible new resource in a manner that is blind to the technology. In other jurisdictions, for example, utilities apply a wind integration cost assumption that burdens new wind projects with a cost associated with ancillary services and operating reserves deemed as necessary to support the projects.

- The use of the Project Viability Calculator allows a more detailed and consistent evaluation of the attributes of a project or transaction that bear upon the likelihood that it will actually lead to delivery of renewable energy. If the PVC were to be used for bilateral contracts, and if the utility's scoring is compared to the IE's scoring, some insights may be gained about the project or transaction's merits.

However, PG&E's methodology has vulnerabilities that come along with these strengths.

- The two-step process for incorporating transmission adders for network upgrade costs into the ranking by market value is complex and time-consuming. It is not employed in evaluating bilaterally negotiated contracts currently but is used primarily for the process of constructing a short list for competitive solicitations. In essence, new resources that are approved through bilateral negotiation are not necessarily scrutinized with the same degree of rigor for their impacts on network upgrade costs as those participating in an RFO.

- The methodology takes into account the cost of potential transmission network upgrades identified by the three California IOUs as necessary when enough new generation is added at a local "cluster" to trigger such a need. However, the evaluation of these costs relies on data provided in Transmission Ranking Cost Reports of the IOUs and on the practices of those utilities in compiling the reports. If the TRCRs provide inconsistent guidance, it can skew or bias the outcome of the valuation with transmission adders.

- PG&E does not currently use the same formal numerical scoring approach for bilaterally negotiated contracts that it requires of offers from its competitive RPS solicitations for the criteria of Project Viability, RPS Goals, Credit and Collateral, and Portfolio Fit, even though observations about the bilateral contract's attributes with respect to these criteria clearly enter into internal decisions about the contract.

- The portfolio fit evaluation does not explicitly estimate the costs to ratepayers of remarketing power procured in off-peak periods when the delivery of energy does not fit with overall portfolio needs.

- In the absence of functioning, liquid, and transparent forward markets for Resource Adequacy and for greenhouse gas emission costs, PG&E must rely on economic projections of the value of these for future years, just as it must rely to some extent on extrapolation of forward curves beyond the time horizon within which broker quotes are available.

The remainder of this section focuses on issues identified in the Energy Division's IE template as specific topics of interest to describe the strengths and weaknesses of PG&E's evaluation methodology.

## 1. COMPARISON OF PG&E'S METHODOLOGY TO THOSE IN OTHER STATES

There is a very wide range of practice among electric utilities in how they conduct competitive procurement for new resources. As noted above, PG&E's methodology is generally more transparent regarding process and criteria, has more safeguards against utility or utility-affiliate self-dealing, and provides an extra degree of outreach to potential Participants. Here are some other general observations:

- As with the PG&E Solicitation Protocol, most utilities specify both a valuation or price criterion and non-valuation criteria for evaluating Offers.

- The range of non-valuation criteria other utilities apply is extremely wide, including attributes employed in PG&E's methodology (credit/collateral, project viability, and their sub-topics) as well as others that PG&E's Solicitation Protocol does not explicitly consider.

- "Portfolio Fit" is seldom used as an explicit non-valuation criterion in offer evaluation outside California.[8] To the extent that valuation methods such as production cost models assign greater value to dispatchable resources and to resources that produce more on peak than off peak, the fit of a resource is captured in that analysis.

- Some utilities have rather narrower criteria for minimum eligibility of offers than required by PG&E.

- Relatively few utilities employ a real-option pricing approach to value generation, as PG&E does for dispatchable resources.[9] More typically, utilities employ production cost or dispatch models, such as PROSYM or STRATEGIST, to evaluate the impact on system operation and cost of a new resource and to identify a least-cost plan. Another common approach is for the utility to value the hourly generation of the new resource using the system marginal cost estimated by such a production cost model. Many utilities, when evaluating renewable resources that are not dispatchable, perform their valuation against an internal, proprietary set of forward curves, as PG&E does.

- It is typical for utilities to use an avoided-cost economics approach to valuing the capacity provided by a new resource, as PG&E does.

- In other jurisdictions, utilities are often allowed to consider integration costs when evaluating intermittent resources such as new wind generation. These cost adders can range from $3 to $10/MWh and are considered appropriate by regulators in those jurisdictions to capture the increased system costs needed to accommodate resources with unpredictable generation profiles.

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[8] Arizona Public Service is employing "Portfolio Fit" as a non-quantitative evaluation criterion in its 2008 renewable solicitation: "APS 2008 Renewable RFP Bidder's Conference, June 25, 2008", page 7. Duke Energy, Nevada Power, and Sierra Pacific use "Portfolio Fit" as an evaluation criterion in their renewable solicitations, but for these companies the term refers specifically to the timing of the utility's RPS obligation and the offered project's ability to come into operation to meet the scheduled need

[9] Such tools are more often used by wholesale marketing and trading firms for valuing contracts

To summarize, when compared to typical practices employed by utilities in other U.S. jurisdictions, PG&E's evaluation methodology appears to be designed to stimulate a more robust response from participants by suppressing some of the constraints applied in other RFPs. One would expect a trade-off that PG&E's more accommodating eligibility requirements may imply more challenges in making projects viable, especially when they are outside the CAISO and need transmission to wheel the power, when the developer is permitting, designing, and constructing a project whose technology is outside his/her experience, and when utility and Participant must negotiate detailed contract terms and conditions that differ considerably from the standard form agreement.

## 2. BIAS AGAINST TECHNOLOGY OR OPERATING CHARACTERISTICS

PG&E's evaluation methodology, unlike those of some other utilities, does not explicitly incorporate a preference for one renewable technology over another (such as for landfill gas over wind power) or for one operating characteristic over another (such as for baseload resources over as-available resources). The market valuation analysis, by which the initial ranking is performed, is designed to be neutral to technology.

That being said, some technologies should tend to score higher than others in PG&E's non-valuation criteria as defined in this solicitation. Offers that use technologies that are well-commercialized and which have been built and placed into operation by the dozens should score higher on "technology viability" than technologies that have only undergone trial in the laboratory or in experimental pilot tests on the scale of kilowatts. Intermittent resources such as wind generation which have relatively poor forecast accuracy on a day-ahead basis should score lower on "portfolio fit" than baseload resources that are relatively firm, such as geothermal or landfill gas projects. PG&E's methodology assigns a higher score for portfolio fit for resources whose energy "PG&E is sure to receive."[10]

These attributes of PG&E's protocol do not appear to be biases intended to tilt towards one technology or one operating regime. Reasonable business judgment should favor resources with energy production that is highly predictable on a day-ahead basis over those with poor firmness and uncertain predictability. To increase the likelihood that PG&E customers will benefit from renewable projects that are built on schedule and deliver the promised levels of generation, the methodology should on average favor projects with well-commercialized technology. If the methodology is administered fairly these attributes of the market valuation and non-valuation scoring process should not result in short list decisions biased towards one technology or operating regime.

## 3. THE ROLE OF "PORTFOLIO FIT" IN PG&E'S OFFER EVALUATION

In the 2008 renewable solicitation, PG&E chose to represent portfolio fit with a numerical score based on a qualitative evaluation of firmness of energy delivery and of the time of delivery of energy delivery. In 2007 and previously PG&E used a quantitative measure to evaluate the hourly and seasonal timing of energy delivery.

[10] "Attachment K – Detailed Least Cost Best Fit Evaluation Criteria", attachment to PG&E's 2008 RPS Solicitation Protocol, page 7

One issue with the design of PG&E's methodology is the challenge of capturing the impact of adding new renewable resources on remarketing costs. To the extent new must-take resources are generating in periods when the utility might otherwise be net long power anyway, such as in the early hours of the morning in springtime, adding the resource may exacerbate the challenge of either dispatching down other resources or remarketing that extra power in a market that does not value it, creating opportunity costs or increasing total system costs to accommodate redispatch.[11] Utilities that employ a production cost or utility dispatch model have the ability to assess quantitatively how the thermal unit commitment may change, how units may need to be redispatched, and what the cost of that may be when a new must-take renewable resource is added.

On an unrelated note, new renewable resources that have poor day-ahead predictability may add to total system costs (relative to new resources that have a firm generation profile or good day-ahead predictability). All else being equal, a risk-averse system operator may choose to commit more dispatchable resources to take into account the volume uncertainty associated with unpredictable resources. More units committed, operating at lower load points, on average may increase total system cost.

PG&E's methodology for market valuation does not have the specific means to review such impacts on unit commitment and dispatch. PG&E's approach to valuing as-available renewable generation basically attributes a low value to the new project's production in those springtime off-peak periods because the forward curve assigns low prices to those hours. However, absent a tool that looks at unit commitment decisions, redispatch decisions, and remarketing costs, these impacts of building intermittent, poorly predictable, must-take generation aren't captured by the analysis (this is not meant to imply that production cost models do an excellent job of capturing the real costs of these impacts). Also, the methodology is required to treat integration costs as zero, even if intermittent wind generation were to increase as a major portion of the overall portfolio.

Consequently, there would seem to be a role for the use of portfolio fit as a criterion in addition to the market valuation step. To the extent that the portfolio fit criterion is designed to capture, even in a non-quantitative way, a sense of the costs or opportunity losses the customer bears when a new must-take resource affects remarketing costs and other system costs when it is added, this criterion may be helpful in the overall RFO evaluation, at the margin.

## 4. GENERATION PROJECT TIMING VS. TRANSMISSION PROJECT TIMING

There are clearly situations in the California power market where the commercial operation date (COD) of a new renewable generation project is dependent on the COD of a major transmission network upgrade, as when a project proposes to interconnect to a yet-to-be-built substation or transmission line of SCE's Tehachapi Renewable Transmission Project

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[11] Hypothetically, a system operator may choose to commit more small thermal units in those hours instead of a few big ones in order to decrease the system minimum load point, increasing system fixed costs that day. The utility that takes delivery of poorly predicted must-take power may need to sell it to other parties at short notice, driving down its price in an illiquid market.

or of SCE's proposed Devers-Palo Verde 2 transmission project. Alternatively, there are situations where a new project can come into commercial operation prior to the COD of a major transmission project, but the value of the project will be harder to realize and the operation and output of the project may be constrained until a major transmission upgrade is completed, as with generators proposing to interconnect in Imperial County and to inject power to IID or SDG&E substations prior to completion of the Sunrise Powerlink project.

In such situations, if the timing of the transmission project's COD is uncertain, it poses additional risks to the renewable power project to the extent that a delay in completing the network upgrade could prevent the utility from taking delivery of the renewable generation, or reduce the value and/or volume of that generation because of transmission congestion. Sadly, in the California market there are uncertainties about the timing of the completion of major transmission upgrades; even though transmission owners can make estimates for how long construction will take once all regulatory approvals are obtained, estimating when approvals are likely to be completed is challenging when the merits or impacts of proposed transmission projects are contentious, as with Devers-Palo Verde 2 and Sunrise Powerlink. The PG&E evaluation committee likely has no better insight into the timing of regulatory approvals than other industry observers.

The modified Project Viability Calculator that PG&E will employ in scoring Offers for the 2009 RPS RFO includes scoring of the subcriterion of Transmission Requirements against specific guidelines. This does not actually score the project based on the degree of the specific mismatch, if any, between generation COD and transmission COD. The criteria scoring guidelines for Transmission Requirements simply score based on how long it is expected for transmission access to become available. (In contrast, the prior protocol used by PG&E in the 2008 RPS RFO explicitly assessed the timing and viability of required transmission upgrades relative to generation COD.)

However, the information developed by the evaluation team regarding timing and viability of transmission upgrades can be used in subjective decision-making to select a short list. Therefore the methodology allows the PG&E team to make a judgment about whether or not to short-list a project for which the proposed COD is threatened by potentially adverse outcomes in the timing of a closely-related transmission upgrade, even if that threat is not reflected in the numerical score for Project Viability.

Is it fair to reject from the short list an Offer in such a situation, where concerns about the timing of a transmission project put into question the value of the project prior to transmission COD? One could argue that it is likely that locations that are currently constrained, in which new generation will suffer lower prices and/or reduced volume because of transmission congestion, will eventually be debottlenecked by network upgrades so that a proposed new renewable project in such a location will sooner or later be freed from the constraint. Allowing the PG&E team to use its judgment in making tradeoffs between market value and the risk of a mismatch between transmission upgrade timing and project COD is a reasonable approach.

## 5. TRANSMISSION COST ANALYSIS

The PG&E methodology provides for four major sources of transmission cost information to be used in valuing Offers when making a short list for a competitive solicitation[12]:

1. For some projects, transmission wheeling costs from an Offer's delivery point outside the CAISO grid to the boundary of the CAISO grid must be estimated. For the purposes of making a short list, the methodology calls for the use of the full cost of third-party transmission tariffs as a proxy for this cost (the Participant has the opportunity to propose a price premium to move its power to a CAISO delivery point in its Offer).

2. Transmission adders published in the IOUs' Transmission Ranking Cost Reports are used as proxies for those network upgrade costs potentially needed to accommodate incremental renewable generation in locations that may become congested. These are not used for evaluating bilateral contracts.

3. If a project has already progressed to an advanced state of development or construction, the specific cost of network upgrades needed to accommodate its incremental production have been estimated in a System Impact Study and/or Feasibility Study through the CAISO interconnection process. This information can enter into negotiations of bilateral contracts.

4. The methodology affords PG&E an opportunity to estimate the cost of "alternative commercial arrangements", such as remarketing the project's power, undertaking swaps, or purchasing non-firm transmission rights, to avoid network upgrades. These estimated cost adders are not employed in evaluating bilateral contracts.

PG&E had procedures in place to obtain publicly available third-party transmission tariffs to apply adders for Offers proposing to deliver at points outside the CAISO. PG&E also had the capability to estimate the feasibility and cost of alternative commercial arrangements. Under the protocol, a Participant should submit the estimated cost of network upgrades if a System Impact Study and/or Feasibility Study have been completed. The TRCR data for both PG&E and the other California IOUs are publicly available.

## 6. WEIGHTINGS APPLIED TO EVALUATION CRITERIA

The PG&E methodology does not use quantitative weights to apply to evaluation criteria. In its current form, the methodology does not provide for, say, an assignment of a 60% weight to market valuation and a 20% weight to project viability in ranking Offers. Instead, a valuation-based ranking is the starting point for decision-making, and PG&E uses subjective judgment to reject or include Offers from the short list using information and scoring of the non-valuation criteria.

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[12] The cost of transmission facilities needed to connect the project to the first point of interconnection in the grid, or "gen-tie" costs, are supposed to be incorporated into the price of the Offer

## 7. POTENTIAL IMPROVEMENTS TO PG&E'S METHODOLOGY

The methodology employed in PG&E's 2008 and 2009 renewable energy solicitations has benefitted from several iterations over the years with input from IEs, guidance from PG&E's PRG, and internal discussions on how to improve the approach. Consequently significant progress has been made to streamline the Offer evaluation process, to encourage participation, to enlarge the pool of possible Participants, and to make the process flexible enough to accommodate a wide range of Offers. Still, incremental improvements are still possible, and this section suggests areas where these may be made.

- Transparency of evaluation criteria: supplier concentration. Supplier concentration, or the degree to which PG&E's RPS procurement portfolio is concentrated in the hands of relatively few counterparties, is a legitimate business concern. In this stage of the development of the industry, several developers of renewable power are start-up enterprises, lack project experience, rely on technologies that have seldom or never been constructed on the massive scale now being undertaken, and face other project-specific risks related to equipment, permitting, site control, etc. It would be imprudent for PG&E to make a short list that placed a large fraction of counterparty risk in the hands of one or two competitors who, for example, had never developed a biomass generation project previously but proposed to construct a number of biomass facilities. The risk of failure to meet RPS goals would be increased if PG&E were to rely on a very few renewable developers to build and operate very large numbers of projects successfully in the next few years, as opposed to several developers with a diverse set of skills, experience, and technologies, each assigned a manageable volume of project awards.

  Supplier concentration is closely related to project viability. The risk of failure to bring a renewable generation project to fruition is one thing; to multiply that risk by including several projects of a single counterparty is another. A small development company that might easily be able to manage a PG&E contract for one or two projects of a dozen MW apiece might find itself overwhelmed if it were awarded a contract for dozens of such projects totaling hundreds of MW, jeopardizing its ability to complete more than a few projects on schedule and on budget.

  Thus, supplier concentration is a commercial consideration that should be seriously considered when making decisions about renewable power procurement. Several of the Offers that were ranked high for market valuation were put forward by firms which lacked project experience in siting, developing, permitting, constructing, and operating generation projects using the specific technologies they proposed. Several proposed projects much larger than any they had previously undertaken.

  However, the attribute of supplier concentration, applicable to a short list or a procurement portfolio as a whole, is not identical to project viability. The current protocol is designed for the evaluation committee to score individual Offers on their stand-alone viability. If, hypothetically, 50 projects offered by one developer each received a score of 4.0 out of 5.0 for project viability, it means that each project individually is quite viable, but it does not mean that accepting all 50 projects and negotiating contracts for all 50 is a viable, prudent, or reasonable strategy for PG&E.

PG&E's Solicitation Protocol does not mention supplier concentration as a criterion for evaluating Offers or as a consideration for selecting Offers for a short list. The procurement plan states that PG&E will use information and scores from evaluation criteria to decide which Offers to include in its short list. This appears to imply that if supplier concentration is not an evaluation criterion, it should not be taken into account in making the short list. In fact, considerations of supplier concentration were a key focus in making the short list, and appropriately so, given the heightened degree of counterparty and project risk present in the 2008 proposals.

PG&E's original procurement plan for the 2008 RPS RFO asserted that the revision in the portfolio fit criterion would allow it to "strike a balance on the shortlist regarding the offers' location, technology, online date, and counterparty concentration"[13] So there is an opening for a consideration of supplier concentration through the portfolio fit scoring. However, the portfolio fit score isn't well suited for this, since the evaluation committee creates a score for each individual Offer, and the decision to avoid excessive concentration must in some cases be based on having accepted several Offers onto the short list. Excess concentration is an attribute of the process of making a short list, not usually an attribute of an individual Offer. In any case, the actual 2008 Solicitation Protocol has no mention of counterparty concentration in the text describing the portfolio fit criterion.

Arroyo Seco Consulting recommends that in future Solicitation Protocols PG&E should explicitly identify supplier concentration as a consideration used in Offer selection. This would improve the transparency to the developer community of how PG&E makes the short list decision. It would make the Solicitation Protocol more consistent with how Offer selection is actually conducted. Supplier concentration need not be a separate evaluation criterion but could, perhaps, be incorporated in the protocol's discussion of the Project Viability criterion or of what factors will be taken into account as subjective judgment is applied to make a short list.

- Transparency of evaluation criteria: emerging technologies. The CPUC decision that conditionally approved PG&E's 2008 RPS Procurement Plan explicitly stated that "We [the Commission] also expect utilities to consider projects which employ emerging technologies." To the extent that such projects are evaluated in RPS solicitations, "utilities may need to develop slightly different evaluation criteria for emerging, pilot and demonstration projects."[14]

  For the 2008 RPS solicitation, PG&E had not as yet modified its Solicitation Protocol to accommodate this concept of setting up different evaluation criteria for emerging technologies within the RPS RFO than for mainstream renewable projects. Indeed, the criterion for project viability explicitly includes a consideration of technology viability: a project that uses an "established technology in wide

13 "2008 Renewable Energy Procurement Plan and Draft Solicitation Protocol of Pacific Gas and Electric Company", August 1, 2007 , CPUC Rulemaking 06-05-027, page 14

14 CPUC Decision 08-02-008, "Opinion Conditionally Accepting Procurement Plans for 2008 RPS Solicitations", February 14, 2008, pages 31-32

commercial use" will score higher than one that is based on a technology "still in R&D stage" or "in demonstration phase or early commercialization."[15]

The CPUC's guidance to consider projects using emerging technologies directly contradicts the overall imperative for utilities to select commercially viable Offers with the greatest likelihood of coming into operation and serving the policy objective of meeting RPS goals. Going forward, the regulator and utility could identify an alternative procurement process than the RPS RFO solicitation for selecting commercial-scale projects based on emerging technologies and awarding contracts.[16]

In the absence of such an alternate process, PG&E should revise its Solicitation Protocol in the next RPS RFO to carve out, set aside, or otherwise target a portion of the short list for Offers based on emerging technologies, a carve-out of candidate Offers for which the technology viability sub-criterion does not apply in the evaluation. Such a revision should include specific guidelines for how PG&E would decide which emerging technologies are deserving of short-listing despite weaker project viability and what portion of volumes in the solicitation should be targeted for these less viable technologies.

- <u>Eligibility criteria: hybrid renewable/fossil technology.</u> In future RPS solicitations, PG&E should give explicit guidance to potential participants about the conditions under which a hybrid renewable/fossil project can be evaluated vs. will be rejected as non-conforming. A few Participants offered multi-fuel projects in this RFO.

  For example, the 2008 RPS Solicitation Protocol is explicit in stating that the objective of this solicitation is to procure RPS-eligible generation from eligible renewable resources. But Section X.B, which describes eligible resources, is silent on the subject of multi-fuel generators which include nonrenewable fuels, whereas the CEC explicitly sets guidelines for how a portion of their production can be RPS-eligible. Section IX, which describes Offer Pricing, does not explicitly call for the Offer to provide proposed prices for the renewable portion of generation alone, and it should. PG&E should improve the transparency of its guidance to developers by explicitly describing the conditions, if any, under which Offers from multi-fuel projects that include nonrenewable fuels will be considered in an RPS RFO or not.

- <u>Inputs to market valuation: extrapolating forward curves.</u> The valuation analysis relies on PG&E making a forward energy curve and volatility curve that stretches far into the future, to the termination date of the longest proposed PPA. This requires extrapolation of gas and electric forwards beyond the furthest date of what is observable based on market transactions or broker quotes; the power market is illiquid beyond a reasonably short time horizon.

[15] "Attachment K – Detailed Least Cost Best Fit Evaluation Criteria", attachment to PG&E's 2008 RPS Solicitation Protocol, page 10

[16] For example, the Emerging Renewable Resource Program, which serves as a vehicle for confirming the commercial feasibility of technologies that have been tested only in a preliminary manner, could possibly form the basis for awarding utility procurement contracts for commercialized projects using these technologies

In extrapolating so far into the future, the PG&E team must assume escalation rates for both gas and power forwards. The gas forwards serve as input to the calculation of projected RA value. Escalating forward gas and power prices at different rates has an effect on the predicted RA price. For example, if the power forward price is extrapolated to escalate faster than gas price, the implied market heat rate increases. This would be consistent with a future in which the gas-fired unit needed at the margin to serve peak demand will be increasingly inefficient. It implies that no technological improvements in unit efficiency are anticipated. It would also imply that a new marginal generating unit's utilization increases over time. This result would affect the projected capacity value used in the market valuation protocol.

Arroyo Seco Consulting suggests that the gas and power forward prices be extrapolated to increase at about the same escalation rate beyond the point in time when the California power market is assumed to be in capacity equilibrium. That would tend to reduce effects on the capacity valuation caused by disparate assumptions about gas and power price escalation.

- Inputs to market valuation: adjustment assumptions. The current market valuation protocol includes adjustments to take into account the likely impact of transmission congestion. The data used to make these adjustments are obsolete and need to be updated.

  Because this step of the market valuation analysis can play a major role affecting the ranking of projects that interconnect in historically congested locales, Arroyo recommends that in future years the public market valuation protocol be expanded to discuss the methodology at a summary level. This would improve the transparency of the solicitation and evaluation process so that potential Participants would better understand the means by which the ranking of their projects in the selection process may be affected by their choice in siting.

# 3. FAIRNESS WITH WHICH PG&E ADMINISTERED THE CONTRACT EVALUATION PROCESS

This section describes the extent to which PG&E's administration of its protocols for Offer evaluation of the 2010-12 PacifiCorp transaction was fair. The overall conclusion is that the process in this case was conducted in a fair and consistent manner, with some issues in the process worthy of detailed review. .

## A. PRINCIPLES USED TO DETERMINE FAIRNESS OF PROCESS

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

- Were affiliate Offers treated the same as non-affiliate?
- Were Participants' questions answered fairly and consistently and the answers made available to all?
- Did the utility ask for "clarifications" that provided the Participant an advantage over others?
- Were Offers given equal credibility in the economic evaluation?
- Was there a reasonable justification for any fixed parameters that enter into the methodology (e.g., RMR values; debt equivalence parameters)?
- What qualitative and quantitative factors were used to evaluate bids?

Another few considerations apply to this specific situation where PG&E is evaluating a contract developed through bilateral negotiations. Questions about the fairness of the administration of the process include:

- Were the same exact procedures used to evaluate this bilaterally negotiated contract used that would have applied if it had been received in a competitive solicitation?
- If not, were the differences in how the bilateral contract was evaluated, compared to how Offers in a competitive solicitation are evaluated, sufficiently material to warrant concerns about the fairness with which Participants in an RFO are treated compared to counterparties to bilateral negotiations?

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

PG&E provided Arroyo Seco Consulting with many detailed inputs to its valuation model and with results of market valuation of the 2010-12 PacifiCorp transaction.

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

- Building an independent valuation model to construct an independent ranking of Offers by net market value, as the basis of comparison of the PacifiCorp transaction to other competing alternatives for procuring renewable energy

- Comparing PG&E's valuation ranking to the IE model's ranking in detail, identifying outliers (e.g. where PG&E ranked an Offer much higher than the IE), 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 IE

- Checking intermediate analysis and inputs to the valuation model, e.g. assignment of Offers to nodes and weighted-average TOD factors, for accuracy and consistency

## C. FAIRNESS OF REJECTION OF OFFERS FOR NONCONFORMITY

Only two Offers from the 2008 RPS RFO were rejected by PG&E for nonconformity to the Solicitation Protocol. Arroyo agreed that PG&E's decision to reject these Offers was fair and reasonable. The bilaterally negotiated 2010-12 PacifiCorp transaction is not subject to the terms of PG&E's solicitation protocols. However, Arroyo judges that it could have easily been submitted as a conforming offer to the 2009 RPS RFO (or the 2008 RFO, had the transaction been available) had the parties agreed that this would have been a preferable course.

## D. REASONABLENESS OF PARAMETERS AND INPUTS

The vast majority of the many parameters and inputs that PG&E used in its evaluation of the 2010-12 PacifiCorp transaction were reasonably chosen, in the opinion of Arroyo Seco Consulting. There is a minor issue regarding the choices PG&E made about inputs that merit discussion.

PG&E used a discount rate of 7.6% to bring future Offer costs and benefits to a 2009 present value. Members of the PG&E evaluation committee indicated that this value is based on PG&E's approved cost of capital proceeding. It represents the approved weighted average after-tax cost of capital (WACC) for PG&E.

A public filing by PG&E Corporation described the approval by the CPUC, on December 20, 2007, of the utility's capital structure and authorized rate of return for 2008, at the same levels as had been approved for 2007.[17] As reported in the filing, the "adopted cost of capital" on a weighted return basis was 8.79%; this is a pre-tax weighted average cost of capital. Applying an assumption for marginal tax rate of 40.75% to the debt component of this adopted pre-tax WACC yields an after-tax WACC of about 7.66%, close to the value used as discount rate.

An open issue is whether 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 considered higher than for regulated utilities. For example, the cost of debt assumed into the California Energy Commission's (CEC's) 2007 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 7.72%[18] compared to PG&E's authorized 6.05%, and the assumed cost of equity underlying the proxy plant developer was 13.28% compared to PG&E's authorized 11.35%.

One could argue that the flow of net benefits of power deliveries from IPPs 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) 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 8.93% pre-tax WACC for the proxy plant cited in the 2007 MPR spreadsheet than to 7.6%. Arroyo Seco Consulting suggests that PG&E use the pre-tax WACC of the proxy plant in the 2008 MPR as the discount rate for the next renewable solicitation.[19]

This issue is mitigated in the case of a contract with PacifiCorp, which is itself a regulated utility. Also, in such a short-term transaction the impact of discounting future cash flows is nil. To the extent, however, that the net valuation of this short-term contract is compared to that of very long-term contracts, the impact of discounting future cash flows on the latter has a strong effect.

### E. OUTSOURCING OF EVALUATION ANALYSIS

PG&E did not outsource any portion of the evaluation of the 2010-12 PacifiCorp transaction.

[17] PG&E Corporation, Form 8-K, filed December 21, 2007

[18] Resolution E-4118, Energy Division of the Public Utilities Commission of the State of California, October 4, 2007, page 24

[19] Note that Arroyo does not suggest the use of a pre-tax IPP WACC as an input parameter to the Black option pricing model utilized for valuing dispatchable generation, described in Attachment K. Arroyo suggests using traditional proxies for the "risk-free rate" input to Black's model, such as U.S. Treasury securities. This discussion of pre-tax IPP WACC applies only to use of a rate for discounting pre-tax benefits and costs of as-available, baseload, and peaking Offers.

## F. TRANSMISSION ANALYSIS AND TRANSMISSION INFORMATION

PG&E did not apply Transmission Ranking Cost Report adders or estimates of the cost of alternative commercial arrangements to the 2010-12 PacifiCorp transaction, even though the power from PacifiCorp will be delivered to a point in the California ISO within on of the transmission clusters identified in PG&E's TRCR. PG&E uses TRCR adders or the cost of alternative commercial arrangements when ranking Offers in competitive solicitations, but does not apply them to the evaluation of bilaterally negotiated contracts.

Arroyo does not consider this feature of PG&E's practices to be unfair in the case of the PacifiCorp transaction. Because the generating facilities from which the power is sourced already exist, continued operation should not have an impact on the need for network upgrades, in contrast to the situation in an RPS RFO which often results in proposed new facilities that may require significant network upgrades.

## G. PG&E'S USE OF OTHER NON-QUANTITATIVE CRITERIA OR ANALYSIS

PG&E's LCBF evaluation methodology involves four non-quantitative that are described in its 2009 RPS RFO solicitation protocol: Portfolio Fit, Credit, Project Viability, and RPS Goals.

PG&E considered how the 2010-12 PacifiCorp transaction performed against each of these criteria. However, the team did not use exactly the same methodology to evaluate the transaction as it prescribes in the 2008 or 2009 RPS RFO protocols. Specifically, the team did not rate the transaction on a numerical score on a scale of 0 to 100 for Portfolio Fit, Credit, and RPS Goals. It did not develop a Project Viability Calculator score for the transaction.

While one might perceive the less rigorous evaluation of a bilaterally negotiated contract against these non-quantitative criteria to be unfair to the participants who submit their offers through a competitive solicitation, Arroyo does not consider this to be a concern in the case of the 2010-12 PacifiCorp transaction. The utility clearly reviewed the portfolio fit of the transaction without developing a numerical score. The transaction was reviewed by PG&E's Credit Department and was held to the same standards that would have applied had it been a short-term transaction offered to the utility in a solicitation assuming that the parties had opted to use an EEI Master Agreement as the basis for the transaction, as allowed in the version of the 2009 Form Agreement adapted for short-term transactions. Many of the subcriteria that are used to score offers with the Project Viability Calculator are useful for evaluating proposed new projects, but not particularly relevant for reviewing existing facilities.

In Arroyo's opinion, the company's decision to not use exactly the same scoring systems to evaluate the 2010-12 PacifiCorp transaction against non-quantitative criteria as it uses in competitive solicitations creates a minor inconsistency, and does not represent unfair treatment of participants in competitive solicitations. In an ideal world the procedures would be identical. Furthermore, bilateral contracts that feature proposed, as-yet-unbuilt facilities should be evaluated using the Project Viability Calculator if the utility is to conform to the directive of Decision 09-06-050 that the Energy Division review bilateral contracts for renewable energy "by using the same methods and criteria as are used to review contracts that are negotiated as a result of a utility's annual solicitation".[20]

When conducting competitive solicitations, PG&E applies at least one criterion other than those identified in its solicitation protocol to make decisions about the short list. This is the consideration of excess supplier concentration in PG&E's overall energy supply portfolio.

In the 2008 RPS RFO, the team applied a general rule of thumb of avoiding a short list that would result in an excessive volume or share for any one Participant. This was a straightforward analytic approach that required subjective judgment to be exercised by the team. Arroyo Seco Consulting's opinion is that criterion of supplier concentration in making a short list is a legitimate business concern closely related to credit risk, and the decisions to exclude Offers based on PG&E's analysis of supplier concentration were fair and reasonable. Future solicitations would benefit if this criterion were made explicit within the solicitation protocol, to increase transparency regarding how PG&E considers this issue as it applies judgment to make a short list.

The PG&E team did not view the execution of the 2010-12 transaction with PacifiCorp as incurring excess concentration in the supply portfolio, so this criterion was not an issue for evaluation of the contract.

## H. ANALYSIS OF PG&E'S SHORT LIST RESULTS

While the PG&E evaluation committee and Arroyo Seco Consulting have previously disagreed on some specific decisions in the administration of PG&E's evaluation process, most of these minor issues were quickly resolved in the course of discussion during the development of a short list for the 2008 RPS RFO. One unresolved issue was the selection of discount rate for use in the valuation methodology.

Arroyo expressed a concern about using an approved utility WACC as the discount rate for net benefit of Offers[21] as opposed to a IPP WACC. This disagreement was not resolved and Arroyo recommends the future use of an IPP WACC, such as the one used in the CEC's MPR analysis for a proxy plant built by independent power developers. Also, Arroyo raised an objection to elevating one low-valued Offer to the short list, based on the inconsistent treatment of competing Offers that were not selected. This was resolved by PG&E replacing it with a different Offer, so that the logic for including that low-valued Offer was fairly and consistently applied to evaluate competitors' Offers as well.

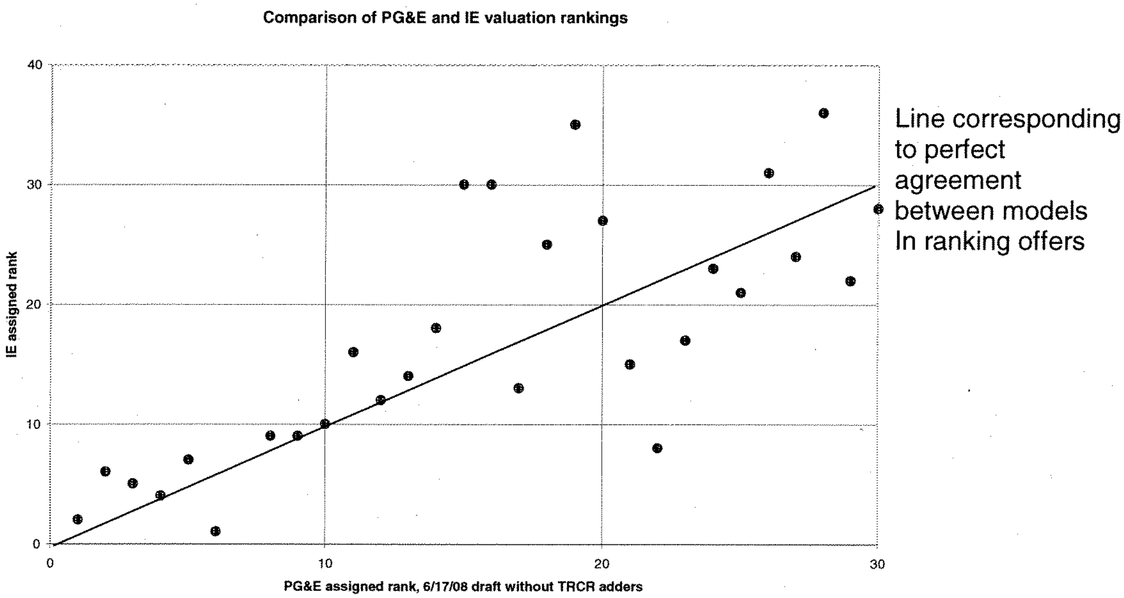
---

[20] California Public Utilities Commission, Decision 09-06-050, "Decision Establishing Price Benchmarks and Contract Review Processes for Short-term and Bilateral Procurement Contracts for Compliance with the California Renewables Portfolio Standard", June 19, 2009

[21] Specifically, as-available, baseload, or peaking Offers valued against a forward curve in nominal dollars and discounted to 2009 dollars

Arroyo employs a rather simple but independent valuation model as a means to check the results of PG&E's LCBF valuation model. Figure 1 shows a comparison of the ranking of the top Offers from the 2008 RPS RFO between the two models; the diagonal line shows where data points would fall if the two models agreed exactly on valuation rankings. The fit between model rankings is imperfect, but is fairly good considering how simplified the IE model is; the comparison is useful for identifying points of disagreement.

Figure 1




Arroyo used the simple model to compare the ranking of the 2010-12 PacifiCorp transaction to other offers available to PG&E for procuring renewable energy. No issues or concerns were identified in comparing results between the two models.

Arroyo concludes that the administration of PG&E's LCBF methodology to evaluate the 2010-12 PacifiCorp transaction was fair.

# 4. ADEQUACY OF OUTREACH TO PARTICIPANTS AND ROBUSTNESS OF THE 2008 SOLICITATION

In its 2008 renewable solicitation, PG&E undertook to meet a goal of procuring 1 to 2% of its retail load through Offers that lead to successfully negotiated contracts. This section, specified by the Energy Division's long-form template for IE reports, discusses an assessment of the degree to which PG&E adequately conducted outreach activities in that RFO to drum up sufficient participation in the solicitation, and the degree to which the solicitation may be judged robust enough to be competitive.

## A. PRINCIPLES TO ASSESS 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?

## B. PRINCIPLES TO ASSESS ROBUSTNESS OF THE SOLICITATION

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

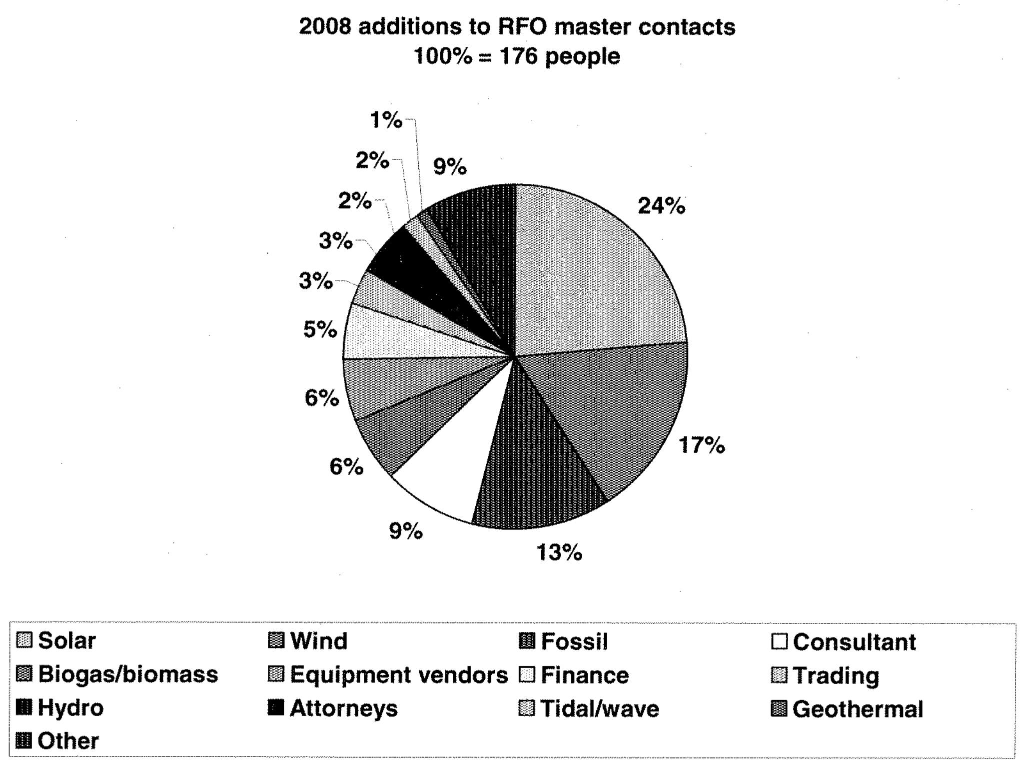
- Was the response to the solicitation large enough for PG&E to reasonably expect to achieve its goal of procuring 1 – 2% of retail load, given the likely attrition of Offers between short list and actual production, without having to accept a majority of Offers?
- Was the response to the solicitation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

- Was the distribution of responses tilted towards projects that were assessed as generally viable, or was there an excess of less viable Offers?

## C. ADEQUACY OF OUTREACH

By the beginning of May 2008, PG&E had compiled a contact list for use in publicizing its 2008 RPS RFO, totaling about 1,022 individuals with unique names and e-mail addresses. Of these, about 176 contacts were clearly identified as having been added in 2008, the period running up to the release of the RPS RFO and through its submittal deadline. When analyzed to attempt to assess which industry the individual contacts represented, the largest segment was made up of individuals in the solar power sector, followed by wind power and fossil-fueled generation. Figure 2 displays the estimated shares by industry sector of these 2008 additions. Note that this contact list is employed not just for renewable solicitations but for all-source RFOs as well.

Figure 2




Inspection of the overall contact list reveals that many of the major developers of renewable energy in North America are included, particularly among solar and wind developers. It cannot be determined from inspecting the contact list whether PG&E proactively sought to add these individuals to the list or whether PG&E reacted to contacts coming to the utility and requesting information about procurement opportunities.

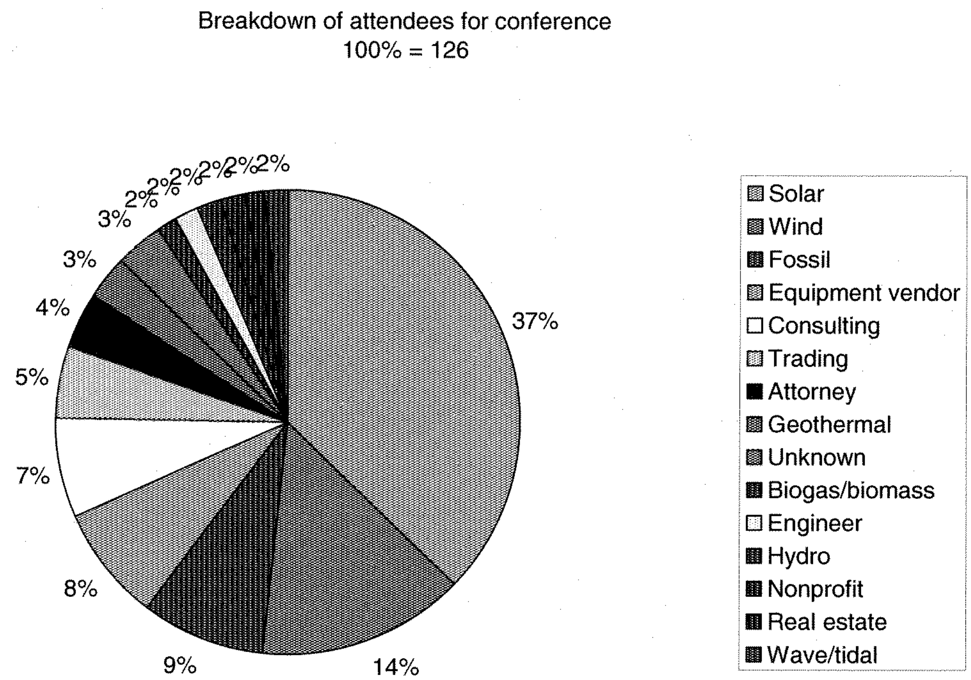
PG&E's press release announcing the issuance of the 2008 RPS RFO was picked up and reported broadly in the electric power trade press, including publications such as:

- Platts Power Markets Week
- Global Power Report
- Megawatt Daily
- Power Market Today
- Targeted News Service
- NewsTrak Daily
- Platts Commodity News
- Dow Jones News Service
- PR Newswire

In additional, the detailed solicitation protocol and its attachments, the schedule, and other RFO informational items were posted on PG&E's website for public access.

Another indicator of the adequacy of the outreach for the RFO was the response of attendees for the bidders' conference. Figure 3 shows the breakdown of individuals who registered for the conference (there is no means to check who actually attended) by the sector of the industry their employer represents. A turnout of 126 individuals is a healthy response. As with the contact list's 2008 additions, the largest share of attendees represented the solar and wind sectors of the renewable industries. While several of the attendees appeared to be individuals representing themselves only, or employees of small consulting firms or non-profit organizations, several other attendees represented leading manufacturers of solar and wind generation hardware and developers of wind and geothermal power projects.

Figure 3




Inspection of the written Offers submitted for the RFO suggests that, while many Participants (particularly those who attended the bidders' workshop or who had participated in prior RPS RFOs) had developed a strong overall comprehension of what information to submit in order to provide a proposal that conformed to the Solicitation Protocol's requirements, many had substantial weaknesses. Two common themes emerged in deficiencies: (1) Participants failed to fill in the fields on the Proposal Project Description for credit information such as their proposed amounts of Project Development Security and Delivery Term Security, and (2) Participants failed to fill in the field for energy pricing without Production Tax Credit (PTC) or 30% Investment Tax Credit (ITC), or they left pricing without PTC and ITC the same as pricing with PTC and ITC. These errors or omissions had to be corrected by sending Participants deficiency letters.

The bidders' workshop presentation dealt with how to fill in these fields in some detail, so it is hard to fault PG&E for insufficient outreach on these specific points. No Offer was disqualified for an initial failure to fill in these fields properly, and participants generally addressed the defects following issuance of the deficiency letters. A recommendation for future solicitations would be to revise the Instructions page in Attachment D to the Offer to clarify exactly what fields on credit information and energy pricing without PTC and ITC must be filled in, with what information, to achieve compliance.

Arroyo Seco Consulting's conclusion is that PG&E conducted substantial outreach to the community of renewable power developers in North America for the 2008 RPS solicitation. The number of individuals contacted, the breadth of distribution of the news of the solicitation in the electric power trade press, and the substantial participation in the bidders' conference suggest that overall outreach was strong. There may be room for future improvement in one specific area, discussed below.

## D. ROBUSTNESS OF SOLICITATION

The Offers PG&E received for the 2008 RPS solicitation total a large volume of projected generation and capacity. The offered volume totaled a substantial fraction of PG&E's expected retail load, and should provide plenty of opportunity for PG&E to negotiate, contract for, and procure 1 to 2% of retail load, taking into account that a number of the Participants chose exclusive negotiation with other utilities instead of PG&E, some projects are likely to fall out of negotiation, and some projects that are contracted may yet fail to be completed and enter commercial operation. The risks of failure may be high in this year's solicitation if only because many of the submitted proposals are for large solar facilities, larger than any actually constructed in the U.S. in the last decade, which may carry substantial execution risk. However, the ratio of offered volume to targeted procurement volume reflects a healthy, robust response, suggesting a strong likelihood that the target will be achieved at some point in time.

The Offers for solar generation were disproportionately represented in the total compared to solar power's portion of 2008 outreach contacts and bidders' conference attendees. This may be a comment on the attractiveness of the solar resource in the southern part of California and the increasing degree to which photovoltaic, solar trough, and solar tower technologies are expected to capture scale economies.

The representation of wind generation in the Offers is roughly the same as its share of the 2008 additions to the PG&E RFO contact list and attendance at the bidders' workshop. The same is true for biomass/biogas and geothermal generation. However, since the contact list and the workshop attendees include large numbers of attorneys, consultants, equipment manufacturers, wholesale power marketers and traders, and farmers or other real estate owners, who are less likely to directly propose actual generation projects, the representation of wind, biomass, and geothermal Offers is rather lower than their representation among actual developers in the contact list additions and workshop attendees.

This may reflect the increased attractiveness of wind power development in other jurisdictions and markets in the U.S. with the more recent implementation of RPS standards elsewhere than California. Or it may reflect the uncertain status of federal tax credit renewal, the scarcity of wind turbines, the relatively high penetration of wind development in California, the relative challenge of the permitting process in California vs. other states, and/or the burden and delay of obtaining transmission access for new California wind projects. This may also represent the technological challenges and risks of developing new geothermal resources and the burden of obtaining transmission access to the CAISO grid from regions where geothermal resources are most attractive.

Without directly obtaining feedback from developers who did not submit Offers (such as those developers who submitted Notices of Intent to participate but chose not to offer) it is hard to know what factors may be limiting the response to the RFO from these other technologies. Arroyo recommends that PG&E make follow-up contacts to the geothermal, biomass, and wind development companies that submitted Notices of Intent but did not make Offers, in order to obtain feedback on their decisions to pass on this solicitation, and possibly to identify how to alleviate impediments to their making Offers in the future.

Executive Order S-06-06 states a goal for California to obtain 20% of its renewable electric generation from biomass. In PG&E's case, the share of renewable power currently procured from biomass generation is already well above that. However, as PG&E continues to succeed in negotiating large procurement contracts for renewable power using other technologies, a need may eventually emerge to increase the share of new procurement represented by biomass. Individuals associated with biomass and biogas generation made up about 6% of the contacts added to PG&E's list in 2008, and biomass and biogas power made up roughly 4% of the production volume of the Offers (not counting hybrid projects utilizing both biomass and other technologies). PG&E may have an opportunity to increase the extent to which it focuses a portion of its outreach to biomass power developers in its future RPS solicitations, along with the company's other innovative programs to capture biogas for commercial use.

## E. SOLICITING FEEDBACK FROM PARTICIPANTS

After arriving at a final short list for the 2008 RPS RFO, PG&E sent e-mails to Participants whose Offers were not selected for the short list. Each communication included an offer to engage in a discussion of that outcome, if desired. About half of these Participants expressed an interest in such a follow-up discussion.

In a few cases, Participants who were notified that their Offers were included in the short list responded by withdrawing the Offers. In these cases PG&E proactively contacted the Participants to seek to find out the reasons for withdrawal from the solicitation. Arroyo concluded that PG&E's efforts to seek adequate feedback from all Participants about the 2008 RFO process were thorough.

# 5. FAIRNESS OF PROJECT-SPECIFIC NEGOTIATIONS

This chapter details an independent review of the extent to which PG&E's negotiations with PacifiCorp for the delivery of renewable power from wind facilities in the three-year period 2010 - 2012 can be considered to be fair. A more detailed narrative of points of the negotiation and how its fairness can be judged is provided in the confidential appendix to this report.

## A. FAIRNESS OF NEGOTIATIONS BETWEEN PACIFICORP AND PG&E

As described previously, because of the timing of the Commission's Decision regarding an IE role in evaluating long-term bilateral contracts, Arroyo did not have an opportunity to participate directly in negotiating sessions between PG&E transactors and PacifiCorp, as has been the case with short-listed parties from the 2008 RPS RFO. As a consequence, Arroyo is unable to opine directly about the treatment of PacifiCorp in those sessions, or how that treatment compares to the treatment of other counterparties with whom PG&E is negotiating, based on direct observation. The limited findings in this section are based more narrowly on reviews of correspondence, such as draft proposals, between the two parties, and a comparison of the resulting executed contract's terms and conditions to those of other draft or executed contracts between PG&E and short-listed participants in the 2008 RPS RFO or resulting from other recent bilateral negotiations.

Based on the paper trail of revisions in contract language in the confirmation agreement, the negotiations between the two parties focused on clarifying and agreeing upon specific commercial aspects of the transaction. There is no evidence that PG&E granted PacifiCorp any unique, unusual, unfair, or unreasonable concessions in the course of negotiating the confirmation agreement. More detail is provided in the confidential appendix to this report.

## B. STRUCTURAL ADVANTAGES TO SELLERS OF THE EEI MASTER AGREEMENT COMPARED TO PG&E'S FORM AGREEMENT

The contract for the 2010-12 transaction between PG&E and PacifiCorp does not resemble either the 2008 or 2009 RPS RFO Form Agreements used for long-term contracts resulting from competitive solicitations. Instead, it closely follows the Edison Electric Institute (EEI) Master Power Purchase and Sale Agreement that serves broadly as an industry standard contract for energy and capacity transactions, and is memorialized in a short-form confirmation agreement. The EEI master agreement is typically used by wholesale marketing and trading entities that might have numerous transactions with an individual counterparty. To the extent that those might include both long and short positions, use of the master agreement benefits the power industry as a whole by employing net margining as the basis for collateral (i.e. counterparty exposure is assessed based on the whole portfolio of contracts one party has with another, not on the sum of individual collateral requirements).

Arroyo has reviewed the executed EEI master agreement and the confirmation agreement for the 2010-12 transaction between PG&E and PacifiCorp. The short-term contract's terms and conditions are advantageous to PacifiCorp in comparison to those of PPAs resulting from the 2008 RPS RFO. PG&E's Form Agreements for renewable solicitations have evolved in recent years to provide stronger protections for ratepayers in areas such as credit and collateral, performance guarantees, and cures for performance failures than the EEI master agreement, which is an industry standard of long standing. The disparity between the terms and conditions of the 2010-12 PacifiCorp contract and those being negotiated with other counterparties could create the appearance that PG&E is treating other counterparties unfairly in using an industry standard contract which PacifiCorp benefits from less stringent terms and conditions. The specific variances are discussed in more detail in the confidential appendix to this report.

In Arroyo's opinion, while a comparison of the specific terms and conditions of the EEI master agreement with PacifiCorp to PG&E's Form Agreement may create the appearance of being less than fully fair to other renewable generators whose contracts are based on the Form Agreement, no other counterparty of PG&E's is demonstrably harmed by executing a short-term contract with PacifiCorp for three years. Similarly, while the EEI master agreement does not provide the level of ratepayer protections embedded in the 2009 Form Agreement as adapted for short-term contracts, and shifts performance risks towards ratepayers compared to such contracts, Arroyo opines that PG&E's ratepayers are likely no worse off with this executed contract than with the alternative of no PacifiCorp contract at all.

The variance between the ratepayer protections offered by the EEI master agreement and PG&E's Form Agreement have more to do with the different histories of how the terms and conditions in the two standard contracts were set, with the former in common use for short-term transactions and the latter applied specifically to long-term RPS contracts. The risk exposure of ratepayers to a three-year power purchase from existing facilities is much less than to a twenty-five-year purchase from a new facility that has not yet been permitted, designed, constructed, or interconnected to the grid. The difference in contractual terms reflects that disparity.

# 6. MERIT FOR CPUC APPROVAL

This chapter provides an independent review of the merits of the proposed 2010-12 PacifiCorp transaction against the high-level criteria identified in the Energy Division's 2008 IE template.

## A. CONTRACT SUMMARY

PG&E and PacifiCorp executed a confirmation agreement for a purchase of renewable power from a set of PacifiCorp's wind facilities on September 15, 2009. The confirmation agreement is pursuant to an EEI master agreement between the two parties executed on September 15, 2009. The contract provides for delivery to PG&E at the California-Oregon Border (a California ISO scheduling point) of shaped and firmed energy from the wind facilities.

PacifiCorp is selling renewable power from eight existing wind generation facilities:

- Seven Mile Hill I, in Carbon County, Wyoming, 99 MW existing capacity
- Seven Mile Hill II, in Carbon County, Wyoming, 19.5 MW
- Glenrock I, in Converse County, Wyoming, 99 MW
- Rolling Hills, in Converse County, Wyoming, 99 MW
- Glenrock III, in Converse County, Wyoming, 39 MW
- Goodnoe Hills, in Klickitat County, Washington, 94 MW
- Marengo II, in Columbia County, Washington, 70 MW
- Wolverine Creek, in Bonneville and Bingham Counties, Idaho, 64.5 MW

With the exception of the Goodnoe Hills and Marengo II facilities, PacifiCorp reports that these projects use General Electric 1.5-MW turbines. The Goodnoe Hill project uses REpower Systems 2-MW turbines; Marengo II uses Vestas 1.8 MW-turbines. Seven of these facilities are PacifiCorp-owned; the energy production of Wolverine Hills is secured by PacifiCorp under long-term contract.

The proposed contract would provide bundled energy including green attributes, scheduled for delivery into the California ISO at the California-Oregon Border (COB). The actual intermittent production of the facilities would be firmed and shaped to a schedule of flat power of 100 MW. The flat deliveries would take place in the first, second, and fourth quarter of each year, omitting the July 1 – September 30 period. The expected generation would thus be 655.2 GWh each in 2010 and 2011, and 657.6 GWh in 2012 (a leap year).

The 2008 template for independent evaluators, provided by the Energy Division, calls for a narrative of the merits of the proposed project on the major categories of contract price, portfolio fit, and project viability. More specific details are provided in the confidential appendix to this report.

CONTRACT PRICE AND MARKET VALUATION

Arroyo has compared the likely cost of the 2010-12 PacifiCorp transaction to peer groups of alternative sources of renewable energy for PG&E. Based on those comparisons, in Arroyo's opinion, the net market valuation for the 2010-12 transaction is likely to rank as moderate.

Arroyo is unable to determine whether or not the contract price will exceed the Market Price Referent (MPR) for ten-year PPAs, using the 2008 baseload MPR for ten-year resources commencing in 2010.[22]. The confidential appendix to this report provides a more detailed discussion of the pricing of the PPA and the basis for Arroyo's opinion that the net value of the contract is likely to be moderate.

PORTFOLIO FIT

Arroyo ranks the 2010-12 PacifiCorp transaction as low in portfolio fit. The energy delivered to PG&E's customers is expected to be shaped as baseload power. While PG&E's portfolio does not have an immediate need for baseload power, the costs of remarketing off-peak power when the delivery is not fully required are likely to be low. The seasonal pattern fails to provide power to PG&E during the third quarter of each year when PG&E's peak needs are greatest.

PROJECT VIABILITY

The project viability of the eight wind generation facilities from which power for the transaction is to be sourced is high. The facilities already exist. All permitting, interconnection, financing, equipment, and site control issues have been dealt with. PacifiCorp has developed or bought several wind facilities and has had years of experience operating and maintaining such facilities.

RPS GOALS

The 2010-12 transaction would advance PG&E towards its RPS goals in the near future. It would advance the utility towards meeting its RPS target for 2010. It would not contribute to the goals set by the Governor's executive order regarding use of biomass or to PG&E's supplier diversity goals.

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[22] California Public Utilities Commission, Resolution E-4214, December 18, 2008, page 1; the baseload MPR for ten-year resources commencing 2010 is $101.75/MWh in nominal dollars.

## C. DISCUSSION OF MERIT FOR APPROVAL

Arroyo concurs with PG&E management that the proposed 2010-12 PacifiCorp contract merits CPUC approval, despite Arroyo's opinion that the transaction's market valuation is likely to be moderate. The transaction offers high project viability and a strong likelihood of contributing to PG&E's RPS target for 2010. In considering the tradeoff between detailed considerations of contract value vs. high project viability, Arroyo acknowledges the importance of advancing the state towards RPS goals in the near term. Similarly, Arroyo does not consider the omission of 100 MW of deliveries during the July – September months, which reduces the contract's fit with PG&E's portfolio, to be a fatal flaw in the transaction.

# 7. CONCLUSIONS

Arroyo Seco Consulting concludes that the LCBF methodology that PG&E employed in evaluating the 2010-12 PacifiCorp contract was fair and reasonable. The administration of the methodology was fair and reasonable. Based on a review of the parties' draft documents and of the terms and conditions of the executed PPA (rather than on direct observation of the actual negotiation process), Arroyo infers indirectly that the negotiations were likely conducted fairly, though the EEI Master Agreement that serves as the basis for the transaction has slightly less favorable terms and conditions for ratepayer protection than PG&E's 2009 Form Agreement.

In Arroyo's opinion, the proposed 2010-12 transaction will likely rank as moderate in net market valuation, is low in portfolio fit, and is high in project viability, and merits CPUC approval.

# Appendix J

# EEI Master Agreement (Public Portion)

# Master Power Purchase & Sale Agreement

EDISON ELECTRIC INSTITUTE

Version 2.1 (modified 4/25/00)

**MASTER POWER PURCHASE AND SALES AGREEMENT**

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# MASTER POWER PURCHASE AND SALE AGREEMENT

## COVER SHEET

This *Master Power Purchase and Sale Agreement* ("*Master Agreement*" ) is made as of the following date: ________________ ("Effective Date"). The *Master Agreement*, together with the exhibits, schedules and any written supplements hereto, the Party A Tariff, if any, the Party B Tariff, if any, any designated collateral, credit support or margin agreement or similar arrangement between the Parties and all Transactions (including any confirmations accepted in accordance with Section 2.3 hereto) shall be referred to as the "Agreement." The Parties to this *Master Agreement* are the following:

Name ("________________" or "Party A")

All Notices:

Street: ______________________________

City: ____________________ Zip: __________

Attn: Contract Administration
Phone: ______________________________
Facsimile: ______________________________
Duns: ______________________________
Federal Tax ID Number: ______________________

**Invoices:**
Attn: ______________________________
Phone: ______________________________
Facsimile: ______________________________

**Scheduling:**
Attn: ______________________________
Phone: ______________________________
Facsimile: ______________________________

**Payments:**
Attn: ______________________________
Phone: ______________________________
Facsimile: ______________________________

**Wire Transfer:**
BNK: ______________________________
ABA: ______________________________
ACCT: ______________________________

**Credit and Collections:**
Attn: ______________________________
Phone: ______________________________
Facsimile: ______________________________

With additional Notices of an Event of Default or Potential Event of Default to:
Attn: ______________________________
Phone: ______________________________
Facsimile: ______________________________

Name ("Counterparty" or "Party B")

All Notices:

Street: ______________________________

City: ____________________ Zip: __________

Attn: Contract Administration
Phone: ______________________________
Facsimile: ______________________________
Duns: ______________________________
Federal Tax ID Number: ______________________

**Invoices:**
Attn: ______________________________
Phone: ______________________________
Facsimile: ______________________________

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Phone: ______________________________
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Phone: ______________________________
Facsimile: ______________________________

**Wire Transfer:**
BNK: ______________________________
ABA: ______________________________
ACCT: ______________________________

**Credit and Collections:**
Attn: ______________________________
Phone: ______________________________
Facsimile: ______________________________

With additional Notices of an Event of Default or Potential Event of Default to:
Attn: ______________________________
Phone: ______________________________
Facsimile: ______________________________

The Parties hereby agree that the General Terms and Conditions are incorporated herein, and to the following provisions as provided for in the General Terms and Conditions:

| | | | |
|---|---|---|---|
| Party A Tariff | Tariff ________________ | Dated ________________ | Docket Number ______________ |
| Party B Tariff | Tariff ________________ | Dated ________________ | Docket Number ______________ |

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**Article Two**

Transaction Terms and Conditions — [] Optional provision in Section 2.4. If not checked, inapplicable.

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**Article Four**

Remedies for Failure to Deliver or Receive — [] Accelerated Payment of Damages. If not checked, inapplicable.

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**Article Five**

Events of Default; Remedies

[] Cross Default for Party A:

[] Party A:________________ Cross Default Amount $_________

[] Other Entity:______________ Cross Default Amount $_________

[] Cross Default for Party B:

[] Party B:________________ Cross Default Amount $_________

[] Other Entity:______________ Cross Default Amount $_________

5.6 Closeout Setoff

[] Option A (Applicable if no other selection is made.)

[] Option B - Affiliates shall have the meaning set forth in the Agreement unless otherwise specified as follows:______________
______________________________________________

[] Option C (No Setoff)

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**Article 8**

Credit and Collateral Requirements

8.1 Party A Credit Protection:

(a) Financial Information:

[] Option A
[] Option B Specify: ________________
[] Option C Specify: ________________

(b) Credit Assurances:

[] Not Applicable
[] Applicable

(c) Collateral Threshold:

[] Not Applicable
[] Applicable

If applicable, complete the following:

Party B Collateral Threshold: $ __________; provided, however, that Party B's Collateral Threshold shall be zero if an Event of Default or Potential Event of Default with respect to Party B has occurred and is continuing.

Party B Independent Amount: $____________

Party B Rounding Amount: $______________

(d) Downgrade Event:

[] Not Applicable
[] Applicable

If applicable, complete the following:

[] It shall be a Downgrade Event for Party B if Party B's Credit Rating falls below __________ from S&P or __________ from Moody's or if Party B is not rated by either S&P or Moody's

[] Other:
Specify:____________________________________________

(e) Guarantor for Party B:____________________________________

Guarantee Amount:____________________________________

8.2 Party B Credit Protection:

(a) Financial Information:

[] Option A
[] Option B Specify: ________________
[] Option C Specify: ________________

(b) Credit Assurances:

[] Not Applicable
[] Applicable

(c) Collateral Threshold:

[] Not Applicable
[] Applicable

If applicable, complete the following:

Party A Collateral Threshold: $ __________; provided, however, that Party A's Collateral Threshold shall be zero if an Event of Default or Potential Event of Default with respect to Party A has occurred and is continuing.

Party A Independent Amount: $____________

Party A Rounding Amount: $______________

(d) Downgrade Event:

[] Not Applicable
[] Applicable

If applicable, complete the following:

[] It shall be a Downgrade Event for Party A if Party A's Credit Rating falls below __________ from S&P or __________ from Moody's or if Party A is not rated by either S&P or Moody's

[] Other:
Specify:______________________________________________

(e) Guarantor for Party A:______________________________________

Guarantee Amount:______________________________________

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**Article 10**

Confidentiality [] Confidentiality Applicable If not checked, inapplicable.

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**Schedule M**

[] Party A is a Governmental Entity or Public Power System
[] Party B is a Governmental Entity or Public Power System
[] Add Section 3.6. If not checked, inapplicable
[] Add Section 8.6. If not checked, inapplicable

**Other Changes** Specify, if any: ______________________________________________

IN WITNESS WHEREOF, the Parties have caused this Master Agreement to be duly executed as of the date first above written.

| Party A Name | Party B Name |
| --- | --- |
| By: ______________________ | By: ______________________ |
| Name: ____________________ | Name: ____________________ |
| Title: _____________________ | Title: _____________________ |

**DISCLAIMER: This Master Power Purchase and Sale Agreement was prepared by a committee of representatives of Edison Electric Institute ("EEI") and National Energy Marketers Association ("NEM") member companies to facilitate orderly trading in and development of wholesale power markets. Neither EEI nor NEM nor any member company nor any of their agents, representatives or attorneys shall be responsible for its use, or any damages resulting therefrom. By providing this Agreement EEI and NEM do not offer legal advice and all users are urged to consult their own legal counsel to ensure that their commercial objectives will be achieved and their legal interests are adequately protected.**

## GENERAL TERMS AND CONDITIONS

### ARTICLE ONE: GENERAL DEFINITIONS

1.1 "Affiliate" means, with respect to any person, any other person (other than an individual) that, directly or indirectly, through one or more intermediaries, controls, or is controlled by, or is under common control with, such person. 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" has the meaning set forth in the Cover Sheet.

1.3 "Bankrupt" means with respect to any entity, such entity (i) 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, (ii) makes an assignment or any general arrangement for the benefit of creditors, (iii) otherwise becomes bankrupt or insolvent (however evidenced), (iv) 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 (v) is generally unable to pay its debts as they fall due.

1.4 "Business Day" means any day except a Saturday, Sunday, or a Federal Reserve Bank holiday. A Business Day shall open at 8:00 a.m. and close at 5:00 p.m. local time for the relevant Party's principal place of business. The relevant Party, in each instance unless otherwise specified, shall be the Party from whom the notice, payment or delivery is being sent and by whom the notice or payment or delivery is to be received.

1.5 "Buyer" means the Party to a Transaction that is obligated to purchase and receive, or cause to be received, the Product, as specified in the Transaction.

1.6 "Call Option" means an Option entitling, but not obligating, the Option Buyer to purchase and receive the Product from the Option Seller at a price equal to the Strike Price for the Delivery Period for which the Option may be exercised, all as specified in the Transaction. Upon proper exercise of the Option by the Option Buyer, the Option Seller will be obligated to sell and deliver the Product for the Delivery Period for which the Option has been exercised.

1.7 "Claiming Party" has the meaning set forth in Section 3.3.

1.8 "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 of this Agreement.

1.9 "Confirmation" has the meaning set forth in Section 2.3.

1.10 "Contract Price" means the price in $U.S. (unless otherwise provided for) to be paid by Buyer to Seller for the purchase of the Product, as specified in the Transaction.

1.11 "Costs" means, with respect to the Non-Defaulting Party, 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 entering into new arrangements which replace a Terminated Transaction; and all reasonable attorneys' fees and expenses incurred by the Non-Defaulting Party in connection with the termination of a Transaction.

1.12 "Credit Rating" means, with respect to any entity, the rating then assigned to such entity's unsecured, senior long-term debt obligations (not supported by third party credit enhancements) or if such entity does not have a rating for its senior unsecured long-term debt, then the rating then assigned to such entity as an issues rating by S&P, Moody's or any other rating agency agreed by the Parties as set forth in the Cover Sheet.

1.13 "Cross Default Amount" means the cross default amount, if any, set forth in the Cover Sheet for a Party.

1.14 "Defaulting Party" has the meaning set forth in Section 5.1.

1.15 "Delivery Period" means the period of delivery for a Transaction, as specified in the Transaction.

1.16 "Delivery Point" means the point at which the Product will be delivered and received, as specified in the Transaction.

1.17 "Downgrade Event" has the meaning set forth on the Cover Sheet.

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

1.19 "Effective Date" has the meaning set forth on the Cover Sheet.

1.20 "Equitable Defenses" means any bankruptcy, insolvency, reorganization and other laws affecting creditors' rights generally, and with regard to equitable remedies, the discretion of the court before which proceedings to obtain same may be pending.

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

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

1.23 "Force Majeure" means an event or circumstance which prevents one Party from performing its obligations under one or more Transactions, which event or circumstance was not anticipated as of the date the Transaction was agreed to, which is not within the reasonable control of, or the result of the negligence of, the Claiming Party, and which, by the exercise of due diligence, the Claiming Party is unable to overcome or avoid or cause to be avoided. Force Majeure shall not be based on (i) the loss of Buyer's markets; (ii) Buyer's inability economically to use or resell the Product purchased hereunder; (iii) the loss or failure of Seller's supply; or (iv) Seller's ability to sell the Product at a price greater than the Contract Price. Neither Party may raise a claim of Force Majeure based in whole or in part on curtailment by a Transmission Provider unless (i) such Party has contracted for firm transmission with a Transmission Provider for the Product to be delivered to or received at the Delivery Point and (ii) such curtailment is due to "force majeure" or "uncontrollable force" or a similar term as defined under the Transmission Provider's tariff; provided, however, that existence of the foregoing factors shall not be sufficient to conclusively or presumptively prove the existence of a Force Majeure absent a showing of other facts and circumstances which in the aggregate with such factors establish that a Force Majeure as defined in the first sentence hereof has occurred. The applicability of Force Majeure to the Transaction is governed by the terms of the Products and Related Definitions contained in Schedule P.

1.24 "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 a Terminated Transaction, determined in a commercially reasonable manner.

1.25 "Guarantor" means, with respect to a Party, the guarantor, if any, specified for such Party on the Cover Sheet.

1.26 "Interest Rate" means, for any date, the lesser of (a) the per annum rate of interest equal to the prime lending rate as may from time to time be published in *The Wall Street Journal* under "Money Rates" on such day (or if not published on such day on the most recent preceding day on which published), plus two percent (2%) and (b) the maximum rate permitted by applicable law.

1.27 "Letter(s) of Credit" means one or more irrevocable, transferable standby letters of credit issued by a U.S. commercial bank or a foreign bank with a U.S. branch with such bank having a credit rating of at least A- from S&P or A3 from Moody's, in a form acceptable to the Party in whose favor the letter of credit is issued. Costs of a Letter of Credit shall be borne by the applicant for such Letter of Credit.

1.28 "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 termination of a Terminated Transaction, determined in a commercially reasonable manner.

1.29 "Master Agreement" has the meaning set forth on the Cover Sheet.

1.30 "Moody's" means Moody's Investor Services, Inc. or its successor.

1.31 "NERC Business Day" means any day except a Saturday, Sunday or a holiday as defined by the North American Electric Reliability Council or any successor organization thereto. A NERC Business Day shall open at 8:00 a.m. and close at 5:00 p.m. local time for the relevant Party's principal place of business. The relevant Party, in each instance unless otherwise specified, shall be the Party from whom the notice, payment or delivery is being sent and by whom the notice or payment or delivery is to be received.

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

1.33 "Offsetting Transactions" mean any two or more outstanding Transactions, having the same or overlapping Delivery Period(s), Delivery Point and payment date, where under one or more of such Transactions, one Party is the Seller, and under the other such Transaction(s), the same Party is the Buyer.

1.34 "Option" means the right but not the obligation to purchase or sell a Product as specified in a Transaction.

1.35 "Option Buyer" means the Party specified in a Transaction as the purchaser of an option, as defined in Schedule P.

1.36 "Option Seller" means the Party specified in a Transaction as the seller of an option , as defined in Schedule P.

1.37 "Party A Collateral Threshold" means the collateral threshold, if any, set forth in the Cover Sheet for Party A.

1.38 "Party B Collateral Threshold" means the collateral threshold, if any, set forth in the Cover Sheet for Party B.

1.39 "Party A Independent Amount" means the amount , if any, set forth in the Cover Sheet for Party A.

1.40 "Party B Independent Amount" means the amount , if any, set forth in the Cover Sheet for Party B.

1.41 "Party A Rounding Amount" means the amount, if any, set forth in the Cover Sheet for Party A.

1.42 "Party B Rounding Amount" means the amount, if any, set forth in the Cover Sheet for Party B.

1.43 "Party A Tariff" means the tariff, if any, specified in the Cover Sheet for Party A.

1.44 "Party B Tariff" means the tariff, if any, specified in the Cover Sheet for Party B.

1.45 "Performance Assurance" means collateral in the form of either cash, Letter(s) of Credit, or other security acceptable to the Requesting Party.

1.46 "Potential Event of Default" means an event which, with notice or passage of time or both, would constitute an Event of Default.

1.47 "Product" means electric capacity, energy or other product(s) related thereto as specified in a Transaction by reference to a Product listed in Schedule P hereto or as otherwise specified by the Parties in the Transaction.

1.48 "Put Option" means an Option entitling, but not obligating, the Option Buyer to sell and deliver the Product to the Option Seller at a price equal to the Strike Price for the Delivery Period for which the option may be exercised, all as specified in a Transaction. Upon proper exercise of the Option by the Option Buyer, the Option Seller will be obligated to purchase and receive the Product.

1.49 "Quantity" means that quantity of the Product that Seller agrees to make available or sell and deliver, or cause to be delivered, to Buyer, and that Buyer agrees to purchase and receive, or cause to be received, from Seller as specified in the Transaction.

1.50 "Recording" has the meaning set forth in Section 2.4.

1.51 "Replacement Price" means the price at which Buyer, acting in a commercially reasonable manner, purchases at the Delivery Point a replacement for any Product specified in a Transaction but not delivered by Seller, plus (i) costs reasonably incurred by Buyer in purchasing such substitute Product and (ii) additional transmission charges, if any, reasonably incurred by Buyer to the Delivery Point, or at Buyer's option, the market price at the Delivery Point for such Product not delivered as determined by Buyer in a commercially reasonable manner; provided, however, in no event shall such price include any penalties, ratcheted demand or similar charges, nor shall Buyer be required to utilize or change its utilization of its owned or controlled assets or market positions to minimize Seller's liability. For the purposes of this definition, Buyer shall be considered to have purchased replacement Product to the extent Buyer shall have entered into one or more arrangements in a commercially reasonable manner whereby Buyer repurchases its obligation to sell and deliver the Product to another party at the Delivery Point.

1.52 "S&P" means the Standard & Poor's Rating Group (a division of McGraw-Hill, Inc.) or its successor.

1.53 "Sales Price" means the price at which Seller, acting in a commercially reasonable manner, resells at the Delivery Point any Product not received by Buyer, deducting from such proceeds any (i) costs reasonably incurred by Seller in reselling such Product and (ii) additional transmission charges, if any, reasonably incurred by Seller in delivering such Product to the third party purchasers, or at Seller's option, the market price at the Delivery Point for such Product not received as determined by Seller in a commercially reasonable manner; provided, however, in no event shall such price include any penalties, ratcheted demand or similar charges, nor shall Seller be required to utilize or change its utilization of its owned or controlled assets, including contractual assets, or market positions to minimize Buyer's liability. For purposes of this definition, Seller shall be considered to have resold such Product to the extent Seller shall have entered into one or more arrangements in a commercially reasonable manner whereby Seller repurchases its obligation to purchase and receive the Product from another party at the Delivery Point.

1.54 "Schedule" or "Scheduling" means the actions of Seller, Buyer and/or their designated representatives, including each Party's Transmission Providers, if applicable, of notifying, requesting and confirming to each other the quantity and type of Product to be delivered on any given day or days during the Delivery Period at a specified Delivery Point.

1.55 "Seller" means the Party to a Transaction that is obligated to sell and deliver, or cause to be delivered, the Product, as specified in the Transaction.

1.56 "Settlement Amount" means, with respect to a Transaction and the Non-Defaulting Party, the Losses or Gains, and Costs, expressed in U.S. Dollars, which such party incurs as a result of the liquidation of a Terminated Transaction pursuant to Section 5.2.

1.57 "Strike Price" means the price to be paid for the purchase of the Product pursuant to an Option.

1.58 "Terminated Transaction" has the meaning set forth in Section 5.2.

1.59 "Termination Payment" has the meaning set forth in Section 5.3.

1.60 "Transaction" means a particular transaction agreed to by the Parties relating to the sale and purchase of a Product pursuant to this Master Agreement.

1.61 "Transmission Provider" means any entity or entities transmitting or transporting the Product on behalf of Seller or Buyer to or from the Delivery Point in a particular Transaction.

## ARTICLE TWO: TRANSACTION TERMS AND CONDITIONS

2.1 Transactions. A Transaction shall be entered into upon agreement of the Parties orally or, if expressly required by either Party with respect to a particular Transaction, in writing, including an electronic means of communication. Each Party agrees not to contest, or assert any defense to, the validity or enforceability of the Transaction entered into in accordance with this Master Agreement (i) based on any law requiring agreements to be in writing or to be signed by the parties, or (ii) based on any lack of authority of the Party or any lack of authority of any employee of the Party to enter into a Transaction.

2.2 Governing Terms. Unless otherwise specifically agreed, each Transaction between the Parties shall be governed by this Master Agreement. This Master Agreement (including all exhibits, schedules and any written supplements hereto), , the Party A Tariff, if any, and the Party B Tariff, if any, any designated collateral, credit support or margin agreement or similar arrangement between the Parties and all Transactions (including any Confirmations accepted in accordance with Section 2.3) shall form a single integrated agreement between the Parties. Any inconsistency between any terms of this Master Agreement and any terms of the Transaction shall be resolved in favor of the terms of such Transaction.

2.3 Confirmation. Seller may confirm a Transaction by forwarding to Buyer by facsimile within three (3) Business Days after the Transaction is entered into a confirmation ("Confirmation") substantially in the form of Exhibit A. If Buyer objects to any term(s) of such Confirmation, Buyer shall notify Seller in writing of such objections within two (2) Business Days of Buyer's receipt thereof, failing which Buyer shall be deemed to have accepted the terms as sent. If Seller fails to send a Confirmation within three (3) Business Days after the Transaction is entered into, a Confirmation substantially in the form of Exhibit A, may be forwarded by Buyer to Seller. If Seller objects to any term(s) of such Confirmation, Seller shall notify Buyer of such objections within two (2) Business Days of Seller's receipt thereof, failing which Seller shall be deemed to have accepted the terms as sent. If Seller and Buyer each send a Confirmation and neither Party objects to the other Party's Confirmation within two (2) Business Days of receipt, Seller's Confirmation shall be deemed to be accepted and shall be the controlling Confirmation, unless (i) Seller's Confirmation was sent more than three (3) Business Days after the Transaction was entered into and (ii) Buyer's Confirmation was sent prior to Seller's Confirmation, in which case Buyer's Confirmation shall be deemed to be accepted and shall be the controlling Confirmation. Failure by either Party to send or either Party to return an executed Confirmation or any objection by either Party shall not invalidate the Transaction agreed to by the Parties.

2.4 Additional Confirmation Terms. If the Parties have elected on the Cover Sheet to make this Section 2.4 applicable to this Master Agreement, when a Confirmation contains provisions, other than those provisions relating to the commercial terms of the Transaction (e.g., price or special transmission conditions), which modify or supplement the general terms and conditions of this Master Agreement (e.g., arbitration provisions or additional representations and warranties), such provisions shall not be deemed to be accepted pursuant to Section 2.3 unless agreed to either orally or in writing by the Parties; provided that the foregoing shall not invalidate any Transaction agreed to by the Parties.

2.5 Recording. Unless a Party expressly objects to a Recording (defined below) at the beginning of a telephone conversation, each Party consents to the creation of a tape or electronic recording ("Recording") of all telephone conversations between the Parties to this Master Agreement, and 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. The Recording, and the terms and conditions described therein, if admissible, shall be the controlling evidence for the Parties' agreement with respect to a particular Transaction in the event a Confirmation is not fully executed (or deemed accepted) by both Parties. Upon full execution (or deemed acceptance) of a Confirmation, such Confirmation shall control in the event of any conflict with the terms of a Recording, or in the event of any conflict with the terms of this Master Agreement.

## ARTICLE THREE: OBLIGATIONS AND DELIVERIES

3.1 Seller's and Buyer's Obligations. With respect to each Transaction, Seller shall sell and deliver, or cause to be delivered, and Buyer shall purchase and receive, or cause to be received, the Quantity of the Product at the Delivery Point, and Buyer shall pay Seller the Contract Price; provided, however, with respect to Options, the obligations set forth in the preceding sentence shall only arise if the Option Buyer exercises its Option in accordance with its terms. Seller shall be responsible for any costs or charges imposed on or associated with the Product or its delivery of the Product up to the Delivery Point. Buyer shall be responsible for any costs or charges imposed on or associated with the Product or its receipt at and from the Delivery Point.

3.2 Transmission and Scheduling. Seller shall arrange and be responsible for transmission service to the Delivery Point and shall Schedule or arrange for Scheduling services with its Transmission Providers, as specified by the Parties in the Transaction, or in the absence thereof, in accordance with the practice of the Transmission Providers, to deliver the Product to the Delivery Point. Buyer shall arrange and be responsible for transmission service at and from the Delivery Point and shall Schedule or arrange for Scheduling services with its Transmission Providers to receive the Product at the Delivery Point.

3.3 Force Majeure. To the extent either Party is prevented by Force Majeure from carrying out, in whole or part, its obligations under the Transaction and such Party (the "Claiming Party") gives notice and details of the Force Majeure to the other Party as soon as practicable, then, unless the terms of the Product specify otherwise, the Claiming Party shall be excused from the performance of its obligations with respect to such Transaction (other than the obligation to make payments then due or becoming due with respect to performance prior to the Force Majeure). The Claiming Party shall remedy the Force Majeure with all reasonable dispatch. The non-Claiming Party shall not be required to perform or resume performance of its obligations to the Claiming Party corresponding to the obligations of the Claiming Party excused by Force Majeure.

## ARTICLE FOUR: REMEDIES FOR FAILURE TO DELIVER/RECEIVE

4.1 Seller Failure. If Seller fails to schedule and/or deliver all or part of the Product pursuant to a Transaction, and such failure is not excused under the terms of the Product or by Buyer's failure to perform, then Seller shall pay Buyer, on the date payment would otherwise be due in respect of the month in which the failure occurred or, if "Accelerated Payment of Damages" is specified on the Cover Sheet, within five (5) Business Days of invoice receipt, an amount for such deficiency equal to the positive difference, if any, obtained by subtracting the Contract Price from the Replacement Price. The invoice for such amount shall include a written statement explaining in reasonable detail the calculation of such amount.

4.2 Buyer Failure. If Buyer fails to schedule and/or receive all or part of the Product pursuant to a Transaction and such failure is not excused under the terms of the Product or by Seller's failure to perform, then Buyer shall pay Seller, on the date payment would otherwise be due in respect of the month in which the failure occurred or, if "Accelerated Payment of Damages" is specified on the Cover Sheet, within five (5) Business Days of invoice receipt, an amount for such deficiency equal to the positive difference, if any, obtained by subtracting the Sales Price from the Contract Price. The invoice for such amount shall include a written statement explaining in reasonable detail the calculation of such amount.

## ARTICLE FIVE: EVENTS OF DEFAULT; REMEDIES

5.1 Events of Default. An "Event of Default" shall mean, with respect to a Party (a "Defaulting Party"), the occurrence of any of the following:

(a) the failure to make, when due, any payment required pursuant to this Agreement if such failure is not remedied within three (3) Business Days after written notice;

(b) any representation or warranty made by such Party herein is false or misleading in any material respect when made or when deemed made or repeated;

(c) the failure to perform any material covenant or obligation set forth in this Agreement (except to the extent constituting a separate Event of Default, and except for such Party's obligations to deliver or receive the Product, the exclusive remedy for which is provided in Article Four) if such failure is not remedied within three (3) Business Days after written notice;

(d) such Party becomes Bankrupt;

(e) the failure of such Party to satisfy the creditworthiness/collateral requirements agreed to pursuant to Article Eight hereof;

(f) 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;

(g) if the applicable cross default section in the Cover Sheet is indicated for such Party, the occurrence and continuation of (i) a default, event of default or other similar condition or event in respect of such Party or any other party specified in the Cover Sheet for such Party under one or more agreements or instruments, individually or collectively, relating to indebtedness for borrowed money in an aggregate amount of not less than the applicable Cross Default Amount (as specified in the Cover Sheet), which results in such indebtedness becoming, or becoming capable at such time of being declared, immediately due and payable or (ii) a default by such Party or any other party specified in the Cover Sheet for such Party in making on the due date therefor one or more payments, individually or collectively, in an aggregate amount of not less than the applicable Cross Default Amount (as specified in the Cover Sheet);

(h) with respect to such Party's Guarantor, if any:

  (i) if any representation or warranty made by a Guarantor in connection with this Agreement is false or misleading in any material respect when made or when deemed made or repeated;

  (ii) the failure of a Guarantor to make any payment required or to perform any other material covenant or obligation in any guaranty made in connection with this Agreement and such failure shall not be remedied within three (3) Business Days after written notice;

(iii) a Guarantor becomes Bankrupt;

(iv) the failure of a Guarantor's guaranty to be in full force and effect for purposes of this Agreement (other than in accordance with its terms) prior to the satisfaction of all obligations of such Party under each Transaction to which such guaranty shall relate without the written consent of the other Party; or

(v) a Guarantor shall repudiate, disaffirm, disclaim, or reject, in whole or in part, or challenge the validity of any guaranty.

5.2 Declaration of an Early Termination Date and Calculation of Settlement Amounts. If an Event of Default with respect to a Defaulting Party shall have occurred and be continuing, the other Party (the "Non-Defaulting Party") shall have the right (i) to designate a day, no earlier than the day such notice is effective and no later than 20 days after such notice is effective, as an early termination date ("Early Termination Date") to accelerate all amounts owing between the Parties and to liquidate and terminate all, but not less than all, Transactions (each referred to as a "Terminated Transaction") between the Parties, (ii) withhold any payments due to the Defaulting Party under this Agreement and (iii) suspend performance. The Non-Defaulting Party shall calculate, in a commercially reasonable manner, a Settlement Amount for each such Terminated Transaction as of the Early Termination Date (or, to the extent that in the reasonable opinion of the Non-Defaulting Party certain of such Terminated Transactions are commercially impracticable to liquidate and terminate or may not be liquidated and terminated under applicable law on the Early Termination Date, as soon thereafter as is reasonably practicable).

5.3 Net Out of Settlement Amounts. The Non-Defaulting Party shall aggregate all Settlement Amounts into a single amount by: netting out (a) all Settlement Amounts that are due to the Defaulting Party, plus, at the option of the Non-Defaulting Party, any cash or other form of security then available to the Non-Defaulting Party pursuant to Article Eight, plus any or all other amounts due to the Defaulting Party under this Agreement against (b) all Settlement Amounts that are due to the Non-Defaulting Party, plus any or all other amounts due to the Non-Defaulting Party under this Agreement, so that all such amounts shall be netted out to a single liquidated amount (the "Termination Payment") payable by one Party to the other. The Termination Payment shall be due to or due from the Non-Defaulting Party as appropriate.

5.4 Notice of Payment of Termination Payment. As soon as practicable after a liquidation, notice shall be given by the Non-Defaulting Party to the Defaulting Party of the amount of the Termination Payment and whether the Termination Payment is due to or due from the Non-Defaulting Party. The notice shall include a written statement explaining in reasonable detail the calculation of such amount. The Termination Payment shall be made by the Party that owes it within two (2) 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 two (2) Business Days of receipt of 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; provided, however, that if the Termination Payment is due from the Defaulting Party, the Defaulting Party shall first transfer Performance Assurance to the Non-Defaulting Party in an amount equal to the Termination Payment.

5.6 Closeout Setoffs.

Option A: After calculation of a Termination Payment in accordance with Section 5.3, if the Defaulting Party would be owed the Termination Payment, the Non-Defaulting Party shall be entitled, at its option and in its discretion, to (i) set off against such Termination Payment any amounts due and owing by the Defaulting Party to the Non-Defaulting Party under any other agreements, instruments or undertakings between the Defaulting Party and the Non-Defaulting Party and/or (ii) to the extent the Transactions are not yet liquidated in accordance with Section 5.2, withhold payment of the Termination Payment to the Defaulting Party. The remedy provided for in this Section shall be without prejudice and in addition to any right of setoff, combination of accounts, lien or other right to which any Party is at any time otherwise entitled (whether by operation of law, contract or otherwise).

Option B: After calculation of a Termination Payment in accordance with Section 5.3, if the Defaulting Party would be owed the Termination Payment, the Non-Defaulting Party shall be entitled, at its option and in its discretion, to (i) set off against such Termination Payment any amounts due and owing by the Defaulting Party or any of its Affiliates to the Non-Defaulting Party or any of its Affiliates under any other agreements, instruments or undertakings between the Defaulting Party or any of its Affiliates and the Non-Defaulting Party or any of its Affiliates and/or (ii) to the extent the Transactions are not yet liquidated in accordance with Section 5.2, withhold payment of the Termination Payment to the Defaulting Party. The remedy provided for in this Section shall be without prejudice and in addition to any right of setoff, combination of accounts, lien or other right to which any Party is at any time otherwise entitled (whether by operation of law, contract or otherwise).

Option C: Neither Option A nor B shall apply.

5.7 Suspension of Performance. Notwithstanding any other provision of this Master Agreement, if (a) an Event of Default or (b) a Potential Event of Default shall have occurred and be continuing, the Non-Defaulting Party, upon written notice to the Defaulting Party, shall have the right (i) to suspend performance under any or all Transactions; provided, however, in no event shall any such suspension continue for longer than ten (10) NERC Business Days with respect to any single Transaction unless an early Termination Date shall have been declared and notice thereof pursuant to Section 5.2 given, and (ii) to the extent an Event of Default shall have occurred and be continuing to exercise any remedy available at law or in equity.

## ARTICLE SIX: PAYMENT AND NETTING

6.1 Billing Period. Unless otherwise specifically agreed upon by the Parties in a Transaction, the calendar month shall be the standard period for all payments under this Agreement (other than Termination Payments and, if "Accelerated Payment of Damages" is specified by the Parties in the Cover Sheet, payments pursuant to Section 4.1 or 4.2 and Option premium payments pursuant to Section 6.7). As soon as practicable after the end of each month, each Party will render to the other Party an invoice for the payment obligations, if any, incurred hereunder during the preceding month.

6.2 Timeliness of Payment. Unless otherwise agreed by the Parties in a Transaction, all invoices under this Master Agreement shall be due and payable in accordance with each Party's invoice instructions on or before the later of the twentieth (20th) day of each month, or tenth (10th) day after receipt of the invoice or, if such day is not a Business Day, then on the next 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 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.

6.3 Disputes and Adjustments of Invoices. A Party may, in good faith, dispute the correctness of any invoice or any adjustment to an invoice, rendered under this Agreement or adjust any invoice for any arithmetic or computational error within twelve (12) months of the date the invoice, or adjustment to an invoice, was rendered. 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. Upon resolution of the dispute, any required payment shall be made within two (2) Business Days of such resolution along with interest accrued at the Interest Rate from and including the due date to 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 to 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 6.3 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 of a Transaction occurred, the right to payment for such performance is waived.

6.4 Netting of Payments. The Parties hereby agree that they shall discharge mutual debts and payment obligations due and owing to each other on the same date pursuant to all Transactions through netting, in which case all amounts owed by each Party to the other Party for the purchase and sale of Products during the monthly billing period under this Master Agreement, including any related damages calculated pursuant to Article Four (unless one of the Parties elects to accelerate payment of such amounts as permitted by Article Four), interest, and payments or credits, shall be netted so that only the excess amount remaining due shall be paid by the Party who owes it.

6.5 Payment Obligation Absent Netting. If no mutual debts or payment obligations exist and only one Party owes a debt or obligation to the other during the monthly billing period, including, but not limited to, any related damage amounts calculated pursuant to Article Four, interest, and payments or credits, that Party shall pay such sum in full when due.

6.6 Security. Unless the Party benefiting from Performance Assurance or a guaranty notifies the other Party in writing, and except in connection with a liquidation and termination in accordance with Article Five, all amounts netted pursuant to this Article Six shall not take into account or include any Performance Assurance or guaranty which may be in effect to secure a Party's performance under this Agreement.

6.7 Payment for Options. The premium amount for the purchase of an Option shall be paid within two (2) Business Days of receipt of an invoice from the Option Seller. Upon exercise of an Option, payment for the Product underlying such Option shall be due in accordance with Section 6.1.

6.8 Transaction Netting. If the Parties enter into one or more Transactions, which in conjunction with one or more other outstanding Transactions, constitute Offsetting Transactions, then all such Offsetting Transactions may by agreement of the Parties, be netted into a single Transaction under which:

(a) the Party obligated to deliver the greater amount of Energy will deliver the difference between the total amount it is obligated to deliver and the total amount to be delivered to it under the Offsetting Transactions, and

(b) the Party owing the greater aggregate payment will pay the net difference owed between the Parties.

Each single Transaction resulting under this Section shall be deemed part of the single, indivisible contractual arrangement between the parties, and once such resulting Transaction occurs, outstanding obligations under the Offsetting Transactions which are satisfied by such offset shall terminate.

## ARTICLE SEVEN: LIMITATIONS

7.1 Limitation of Remedies, Liability and Damages. EXCEPT AS SET FORTH HEREIN, THERE IS NO WARRANTY OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE, AND ANY AND ALL IMPLIED WARRANTIES ARE DISCLAIMED. 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. IF NO REMEDY OR MEASURE OF DAMAGES IS EXPRESSLY PROVIDED HEREIN OR IN A TRANSACTION, 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. 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: CREDIT AND COLLATERAL REQUIREMENTS

8.1 Party A Credit Protection. The applicable credit and collateral requirements shall be as specified on the Cover Sheet. If no option in Section 8.1(a) is specified on the Cover Sheet, Section 8.l(a) Option C shall apply exclusively. If none of Sections 8.1(b), 8.1(c) or 8.1(d) are specified on the Cover Sheet, Section 8.1(b) shall apply exclusively.

(a) Financial Information. Option A: If requested by Party A, Party B shall deliver (i) within 120 days following the end of each fiscal year, a copy of Party B's annual report containing audited consolidated financial statements for such fiscal year and (ii) within 60 days after the end of each of its first three fiscal quarters of each fiscal year, a copy of Party B'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 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 Party B diligently pursues the preparation, certification and delivery of the statements.

Option B: If requested by Party A, Party B shall deliver (i) within 120 days following the end of each fiscal year, a copy of the annual report containing audited consolidated financial statements for such fiscal year for the party(s) specified on the Cover Sheet and (ii) within 60 days after the end of each of its first three fiscal quarters of each fiscal year, a copy of quarterly report containing unaudited consolidated financial statements for such fiscal quarter for the party(s) specified on the Cover Sheet. 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 the relevant entity diligently pursues the preparation, certification and delivery of the statements.

Option C: Party A may request from Party B the information specified in the Cover Sheet.

(b) Credit Assurances. If Party A has reasonable grounds to believe that Party B's creditworthiness or performance under this Agreement has become unsatisfactory, Party A will provide Party B with written notice requesting Performance Assurance in an amount determined by Party A in a commercially reasonable manner. Upon receipt of such notice Party B shall have three (3) Business Days to remedy the situation by providing such Performance Assurance to Party A. In the event that Party B fails to provide such Performance Assurance, or a guaranty or other credit assurance acceptable to Party A within three (3) Business Days of receipt of notice, then an Event of Default under Article Five will be deemed to have occurred and Party A will be entitled to the remedies set forth in Article Five of this Master Agreement.

(c) Collateral Threshold. If at any time and from time to time during the term of this Agreement (and notwithstanding whether an Event of Default has occurred), the Termination Payment that would be owed to Party A plus Party B's Independent Amount, if any, exceeds the Party B Collateral Threshold, then Party A, on any Business Day, may request that Party B provide Performance Assurance in an amount equal to the amount by which the Termination Payment plus Party B's Independent Amount, if any, exceeds the Party B Collateral Threshold (rounding upwards for any fractional amount to the next Party B Rounding Amount) ("Party B Performance Assurance"), less any Party B Performance Assurance already posted with Party A. Such Party B Performance Assurance shall be delivered to Party A within three (3) Business Days of the date of such request. On any Business Day (but no more frequently than weekly with respect to Letters of Credit and daily with respect to cash), Party B, at its sole cost, may request that such Party B Performance Assurance be reduced correspondingly to the amount of such excess Termination Payment plus Party B's Independent Amount, if any, (rounding upwards for any fractional amount to the next Party B Rounding Amount). In the event that Party B fails to provide Party B Performance Assurance pursuant to the terms of this Article Eight within three (3) Business Days, then an Event of Default under Article Five shall be deemed to have occurred and Party A will be entitled to the remedies set forth in Article Five of this Master Agreement.

For purposes of this Section 8.1(c), the calculation of the Termination Payment shall be calculated pursuant to Section 5.3 by Party A as if all outstanding Transactions had been liquidated, and in addition thereto, shall include all amounts owed but not yet paid by Party B to Party A, whether or not such amounts are due, for performance already provided pursuant to any and all Transactions.

(d) Downgrade Event. If at any time there shall occur a Downgrade Event in respect of Party B, then Party A may require Party B to provide Performance Assurance in an amount determined by Party A in a commercially reasonable manner. In the event Party B shall fail to provide such Performance Assurance or a guaranty or other credit assurance acceptable to Party A within three (3) Business Days of receipt of notice, then an Event of Default shall be deemed to have occurred and Party A will be entitled to the remedies set forth in Article Five of this Master Agreement.

(e) If specified on the Cover Sheet, Party B shall deliver to Party A, prior to or concurrently with the execution and delivery of this Master Agreement a guarantee in an amount not less than the Guarantee Amount specified on the Cover Sheet and in a form reasonably acceptable to Party A.

8.2 Party B Credit Protection. The applicable credit and collateral requirements shall be as specified on the Cover Sheet. If no option in Section 8.2(a) is specified on the Cover Sheet, Section 8.2(a) Option C shall apply exclusively. If none of Sections 8.2(b), 8.2(c) or 8.2(d) are specified on the Cover Sheet, Section 8.2(b) shall apply exclusively.

(a) Financial Information. Option A: If requested by Party B, Party A shall deliver (i) within 120 days following the end of each fiscal year, a copy of Party A's annual report containing audited consolidated financial statements for such fiscal year and (ii) within 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 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.

Option B: If requested by Party B, Party A shall deliver (i) within 120 days following the end of each fiscal year, a copy of the annual report containing audited consolidated financial statements for such fiscal year for the party(s) specified on the Cover Sheet and (ii) within 60 days after the end of each of its first three fiscal quarters of each fiscal year, a copy of quarterly report containing unaudited consolidated financial statements for such fiscal quarter for the party(s) specified on the Cover Sheet. 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 the relevant entity diligently pursues the preparation, certification and delivery of the statements.

Option C: Party B may request from Party A the information specified in the Cover Sheet.

(b) Credit Assurances. If Party B has reasonable grounds to believe that Party A's creditworthiness or performance under this Agreement has become unsatisfactory, Party B will provide Party A with written notice requesting Performance Assurance in an amount determined by Party B in a commercially reasonable manner. Upon receipt of such notice Party A shall have three (3) Business Days to remedy the situation by providing such Performance Assurance to Party B. In the event that Party A fails to provide such Performance Assurance, or a guaranty or other credit assurance acceptable to Party B within three (3) Business Days of receipt of notice, then an Event of Default under Article Five will be deemed to have occurred and Party B will be entitled to the remedies set forth in Article Five of this Master Agreement.

(c) Collateral Threshold. If at any time and from time to time during the term of this Agreement (and notwithstanding whether an Event of Default has occurred), the Termination Payment that would be owed to Party B plus Party A's Independent Amount, if any, exceeds the Party A Collateral Threshold, then Party B, on any Business Day, may request that Party A provide Performance Assurance in an amount equal to the amount by which the Termination Payment plus Party A's Independent Amount, if any, exceeds the Party A Collateral

Threshold (rounding upwards for any fractional amount to the next Party A Rounding Amount) ("Party A Performance Assurance"), less any Party A Performance Assurance already posted with Party B. Such Party A Performance Assurance shall be delivered to Party B within three (3) Business Days of the date of such request. On any Business Day (but no more frequently than weekly with respect to Letters of Credit and daily with respect to cash), Party A, at its sole cost, may request that such Party A Performance Assurance be reduced correspondingly to the amount of such excess Termination Payment plus Party A's Independent Amount, if any, (rounding upwards for any fractional amount to the next Party A Rounding Amount). In the event that Party A fails to provide Party A Performance Assurance pursuant to the terms of this Article Eight within three (3) Business Days, then an Event of Default under Article Five shall be deemed to have occurred and Party B will be entitled to the remedies set forth in Article Five of this Master Agreement.

For purposes of this Section 8.2(c), the calculation of the Termination Payment shall be calculated pursuant to Section 5.3 by Party B as if all outstanding Transactions had been liquidated, and in addition thereto, shall include all amounts owed but not yet paid by Party A to Party B, whether or not such amounts are due, for performance already provided pursuant to any and all Transactions.

(d) Downgrade Event. If at any time there shall occur a Downgrade Event in respect of Party A, then Party B may require Party A to provide Performance Assurance in an amount determined by Party B in a commercially reasonable manner. In the event Party A shall fail to provide such Performance Assurance or a guaranty or other credit assurance acceptable to Party B within three (3) Business Days of receipt of notice, then an Event of Default shall be deemed to have occurred and Party B will be entitled to the remedies set forth in Article Five of this Master Agreement.

(e) If specified on the Cover Sheet, Party A shall deliver to Party B, prior to or concurrently with the execution and delivery of this Master Agreement a guarantee in an amount not less than the Guarantee Amount specified on the Cover Sheet and in a form reasonably acceptable to Party B.

8.3 Grant of Security Interest/Remedies. To secure its obligations under this Agreement and to the extent either or both Parties deliver Performance Assurance hereunder, each Party (a "Pledgor") hereby grants to the other Party (the "Secured Party") a present and continuing security interest in, and lien on (and right of setoff against), and assignment of, all cash collateral and cash equivalent collateral and any and all proceeds resulting therefrom or the liquidation thereof, whether now or hereafter held by, on behalf of, or for the benefit of, such Secured Party, and each Party agrees to take such action as the other Party reasonably requires in order to perfect the Secured Party's first-priority security interest in, and lien on (and right of setoff against), such collateral and any and all proceeds resulting therefrom or from the liquidation thereof. Upon or any time after the occurrence or deemed occurrence and during the continuation of an Event of Default or an Early Termination Date, the Non-Defaulting Party may do any one or more of the following: (i) exercise any of the rights and remedies of a Secured Party with respect to all Performance Assurance, including any such rights and remedies under law then in effect; (ii) exercise its rights of setoff against any and all property of the Defaulting Party in the possession of the Non-Defaulting Party or its agent; (iii) draw on any outstanding

Letter of Credit issued for its benefit; and (iv) liquidate all Performance Assurance then held by or for the benefit of the Secured Party free from any claim or right of any nature whatsoever of the Defaulting Party, including any equity or right of purchase or redemption by the Defaulting Party. The Secured Party shall apply the proceeds of the collateral realized upon the exercise of any such rights or remedies to reduce the Pledgor's obligations under the Agreement (the Pledgor remaining liable for any amounts owing to the Secured Party after such application), subject to the Secured Party's obligation to return any surplus proceeds remaining after such obligations are satisfied in full.

## ARTICLE NINE: GOVERNMENTAL CHARGES

9.1 Cooperation. Each Party shall use reasonable efforts to implement the provisions of and to administer this Master 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 government authority("Governmental Charges") on or with respect to the Product or a Transaction arising prior to the Delivery Point. Buyer shall pay or cause to be paid all Governmental Charges on or with respect to the Product or a Transaction at and from the Delivery Point (other than ad valorem, franchise or income taxes which are related to the sale of the Product and are, therefore, the responsibility of the Seller). 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 the amount of any such Governmental Charges from the sums due to Seller under Article 6 of this Agreement. 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.

## ARTICLE TEN: MISCELLANEOUS

10.1 Term of Master Agreement. The term of this Master Agreement shall commence on the Effective Date and shall remain in effect until terminated by either Party upon (thirty) 30 days' prior written notice; provided, however, that such termination shall not affect or excuse the performance of either Party under any provision of this Master Agreement that by its terms survives any such termination and, provided further, that this Master Agreement and any other documents executed and delivered hereunder shall remain in effect with respect to the Transaction(s) entered into prior to the effective date of such termination until both Parties have fulfilled all of their obligations with respect to such Transaction(s), or such Transaction(s) that have been terminated under Section 5.2 of this Agreement.

10.2 Representations and Warranties. On the Effective Date and the date of entering into each Transaction, 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 legally perform its obligations under this Master Agreement and each Transaction (including any Confirmation accepted in accordance with Section 2.3);

(iii) the execution, delivery and performance of this Master Agreement and each Transaction (including any Confirmation accepted in accordance with Section 2.3) are 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 law, rule, regulation, order or the like applicable to it;

(iv) this Master Agreement, each Transaction (including any Confirmation accepted in accordance with Section 2.3), and each other document executed and delivered in accordance with this Master Agreement constitutes its 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 Master Agreement and each Transaction (including any Confirmation accepted in accordance with Section 2.3);

(vii) no Event of Default or Potential 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 Master Agreement and each Transaction (including any Confirmation accepted in accordance with Section 2.3);

(viii) it is acting for its own account, has made its own independent decision to enter into this Master Agreement and each Transaction (including any Confirmation accepted in accordance with Section 2.3) and as to whether this Master Agreement and each such Transaction (including any Confirmation accepted in accordance with Section 2.3) 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 Master Agreement and each Transaction (including any Confirmation accepted in accordance with Section 2.3);

(ix) it is a "forward contract merchant" within the meaning of the United States Bankruptcy Code;

(x) it has entered into this Master Agreement and each Transaction (including any Confirmation accepted in accordance with Section 2.3) in connection with the conduct of its business and it has the capacity or ability to make or take delivery of all Products referred to in the Transaction to which it is a Party;

(xi) with respect to each Transaction (including any Confirmation accepted in accordance with Section 2.3) involving the purchase or sale of a Product or an Option, it is a producer, processor, commercial user or merchant handling the Product, and it is entering into such Transaction for purposes related to its business as such; and

(xii) the material economic terms of each Transaction are subject to individual negotiation by the Parties.

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

10.4 Indemnity. Each Party shall indemnify, defend and hold harmless the other Party from and against any Claims arising from or out of any event, circumstance, act or incident first occurring or existing during the period when control and title to Product is vested in such Party as provided in Section 10.3. Each Party shall indemnify, defend and hold harmless the other Party against any Governmental Charges for which such Party is responsible under Article Nine.

10.5 Assignment. Neither Party shall assign this Agreement or its rights hereunder without the prior written consent of the other Party, which consent may be withheld in the exercise of its sole discretion; provided, however, either Party may, without the consent of the other Party (and without relieving itself from liability hereunder), (i) transfer, sell, pledge, encumber or assign this Agreement or the accounts, revenues or proceeds hereof in connection with any financing or other financial arrangements, (ii) transfer or assign this Agreement to an affiliate of such Party which affiliate's creditworthiness is equal to or higher than that of such Party, or (iii) transfer or assign this Agreement to any person or entity succeeding to all or substantially all of the assets whose creditworthiness is equal to or higher than that of such Party; provided, however, that in each such case, any such assignee shall agree in writing to be bound by the terms and conditions hereof and so long as the transferring Party delivers such tax and enforceability assurance as the non-transferring Party may reasonably request.

10.6 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 NEW YORK, WITHOUT REGARD TO PRINCIPLES OF CONFLICTS OF LAW. EACH PARTY WAIVES ITS RESPECTIVE RIGHT TO ANY JURY TRIAL WITH RESPECT TO ANY LITIGATION ARISING UNDER OR IN CONNECTION WITH THIS AGREEMENT.

10.7 Notices. All notices, requests, statements or payments shall be made as specified in the Cover Sheet. Notices (other than scheduling requests) shall, unless otherwise specified herein, be in writing and may be delivered by hand delivery, United States mail, overnight courier service or facsimile. Notice by facsimile or hand delivery shall be effective at the close of business on the day actually received, if received during business hours on a Business Day, and otherwise shall be effective at the close of business on the next Business Day. Notice by overnight United States mail or courier shall be effective on the next Business Day after it was sent. A Party may change its addresses by providing notice of same in accordance herewith.

10.8 General. This Master Agreement (including the exhibits, schedules and any written supplements hereto), the Party A Tariff, if any, the Party B Tariff, if any, any designated collateral, credit support or margin agreement or similar arrangement between the Parties and all Transactions (including any Confirmation accepted in accordance with Section 2.3) constitute the entire agreement between the Parties relating to the subject matter. Notwithstanding the foregoing, any collateral, credit support or margin agreement or similar arrangement between the Parties shall, upon designation by the Parties, be deemed part of this Agreement and shall be incorporated herein by reference. 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 herein provided for, no amendment or modification to this Master Agreement shall be enforceable unless reduced to writing and executed by both Parties. Each Party agrees if it seeks to amend any applicable wholesale power sales tariff during the term of this Agreement, such amendment will not in any way affect outstanding Transactions under this Agreement without the prior written consent of the other Party. Each Party further agrees that it will not assert, or defend itself, on the basis that any applicable tariff is inconsistent with this Agreement. 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. Any provision declared or rendered unlawful by any applicable court of law or regulatory agency or deemed unlawful because of a statutory change (individually or collectively, such events referred to as "Regulatory Event") will not otherwise affect the remaining lawful obligations that arise under this Agreement; and provided, further, that if a Regulatory Event occurs, the Parties shall use their best efforts to reform this Agreement in order to give effect to the original intention of the Parties. 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. The headings used herein are for convenience and reference purposes only. All indemnity and audit rights shall survive the termination of this Agreement for twelve (12) months. This Agreement shall be binding on each Party's successors and permitted assigns.

10.9 Audit. Each Party has the right, at its sole expense and during normal working hours, 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 Master Agreement. If requested, a Party shall provide to the other Party statements evidencing the Quantity delivered at the Delivery Point. 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 Forward Contract. The Parties acknowledge and agree that all Transactions constitute "forward contracts" within the meaning of the United States Bankruptcy Code.

10.11 Confidentiality. If the Parties have elected on the Cover Sheet to make this Section 10.11 applicable to this Master Agreement, neither Party shall disclose the terms or conditions of a Transaction under this Master Agreement to a third party (other than the Party's employees, lenders, counsel, accountants or advisors who have a need to know such information and have agreed to keep such terms confidential) except in order to comply with any applicable law, regulation, or any exchange, control area or independent system operator rule or in connection with any court or regulatory proceeding; provided, however, each Party shall, to the extent practicable, use reasonable efforts to prevent or limit the disclosure. 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.

## SCHEDULE M

**(THIS SCHEDULE IS INCLUDED IF THE APPROPRIATE BOX ON THE COVER SHEET IS MARKED INDICATING A PARTY IS A GOVERNMENTAL ENTITY OR PUBLIC POWER SYSTEM)**

A. The Parties agree to add the following definitions in Article One.

"Act" means ______________________________.[1]

"Governmental Entity or Public Power System" means a municipality, county, governmental board, public power authority, public utility district, joint action agency, or other similar political subdivision or public entity of the United States, one or more States or territories or any combination thereof.

"Special Fund" means a fund or account of the Governmental Entity or Public Power System set aside and or pledged to satisfy the Public Power System's obligations hereunder out of which amounts shall be paid to satisfy all of the Public Power System's obligations under this Master Agreement for the entire Delivery Period.

B. The following sentence shall be added to the end of the definition of "Force Majeure" in Article One.

If the Claiming Party is a Governmental Entity or Public Power System, Force Majeure does not include any action taken by the Governmental Entity or Public Power System in its governmental capacity.

C. The Parties agree to add the following representations and warranties to Section 10.2:

Further and with respect to a Party that is a Governmental Entity or Public Power System, such Governmental Entity or Public Power System represents and warrants to the other Party continuing throughout the term of this Master Agreement, with respect to this Master Agreement and each Transaction, as follows: (i) all acts necessary to the valid execution, delivery and performance of this Master Agreement, including without limitation, competitive bidding, public notice, election, referendum, prior appropriation or other required procedures has or will be taken and performed as required under the Act and the Public Power System's ordinances, bylaws or other regulations, (ii) all persons making up the governing body of Governmental Entity or Public Power System are the duly elected or appointed incumbents in their positions and hold such

[1] Cite the state enabling and other relevant statutes applicable to Governmental Entity or Public Power System.

positions in good standing in accordance with the Act and other applicable law, (iii) entry into and performance of this Master Agreement by Governmental Entity or Public Power System are for a proper public purpose within the meaning of the Act and all other relevant constitutional, organic or other governing documents and applicable law, (iv) the term of this Master Agreement does not extend beyond any applicable limitation imposed by the Act or other relevant constitutional, organic or other governing documents and applicable law, (v) the Public Power System's obligations to make payments hereunder are unsubordinated obligations and such payments are (a) operating and maintenance costs (or similar designation) which enjoy first priority of payment at all times under any and all bond ordinances or indentures to which it is a party, the Act and all other relevant constitutional, organic or other governing documents and applicable law or (b) otherwise not subject to any prior claim under any and all bond ordinances or indentures to which it is a party, the Act and all other relevant constitutional, organic or other governing documents and applicable law and are available without limitation or deduction to satisfy all Governmental Entity or Public Power System' obligations hereunder and under each Transaction or (c) are to be made solely from a Special Fund, (vi) entry into and performance of this Master Agreement and each Transaction by the Governmental Entity or Public Power System will not adversely affect the exclusion from gross income for federal income tax purposes of interest on any obligation of Governmental Entity or Public Power System otherwise entitled to such exclusion, and (vii) obligations to make payments hereunder do not constitute any kind of indebtedness of Governmental Entity or Public Power System or create any kind of lien on, or security interest in, any property or revenues of Governmental Entity or Public Power System which, in either case, is proscribed by any provision of the Act or any other relevant constitutional, organic or other governing documents and applicable law, any order or judgment of any court or other agency of government applicable to it or its assets, or any contractual restriction binding on or affecting it or any of its assets.

D. The Parties agree to add the following sections to Article Three:

Section 3.4 Public Power System's Deliveries. On the Effective Date and as a condition to the obligations of the other Party under this Agreement, Governmental Entity or Public Power System shall provide the other Party hereto (i) certified copies of all ordinances, resolutions, public notices and other documents evidencing the necessary authorizations with respect to the execution, delivery and performance by Governmental Entity or Public Power System of this Master Agreement and (ii) an opinion of counsel for Governmental Entity or Public Power System, in form and substance reasonably satisfactory to the Other Party, regarding the validity, binding effect and enforceability of this Master Agreement against Governmental Entity or Public Power System in respect of the Act and all other relevant constitutional organic or other governing documents and applicable law.

Section 3.5 No Immunity Claim. Governmental Entity or Public Power System warrants and covenants that with respect to its contractual obligations hereunder and performance thereof, it will not claim immunity on the grounds of sovereignty or similar grounds with respect to itself or its revenues or assets from (a) suit, (b) jurisdiction of court (including a court located outside the jurisdiction of its organization), (c) relief by way of injunction, order for specific performance or recovery of property, (d) attachment of assets, or (e) execution or enforcement of any judgment.

E. If the appropriate box is checked on the Cover Sheet, as an alternative to selecting one of the options under Section 8.3, the Parties agree to add the following section to Article Three:

Section 3.6 Governmental Entity or Public Power System Security. With respect to each Transaction, Governmental Entity or Public Power System shall either (i) have created and set aside a Special Fund or (ii) upon execution of this Master Agreement and prior to the commencement of each subsequent fiscal year of Governmental Entity or Public Power System during any Delivery Period, have obtained all necessary budgetary approvals and certifications for payment of all of its obligations under this Master Agreement for such fiscal year; any breach of this provision shall be deemed to have arisen during a fiscal period of Governmental Entity or Public Power System for which budgetary approval or certification of its obligations under this Master Agreement is in effect and, notwithstanding anything to the contrary in Article Four, an Early Termination Date shall automatically and without further notice occur hereunder as of such date wherein Governmental Entity or Public Power System shall be treated as the Defaulting Party. Governmental Entity or Public Power System shall have allocated to the Special Fund or its general funds a revenue base that is adequate to cover Public Power System's payment obligations hereunder throughout the entire Delivery Period.

F. If the appropriate box is checked on the Cover Sheet, the Parties agree to add the following section to Article Eight:

Section 8.4 Governmental Security. As security for payment and performance of Public Power System's obligations hereunder, Public Power System hereby pledges, sets over, assigns and grants to the other Party a security interest in all of Public Power System's right, title and interest in and to [specify collateral].

G. The Parties agree to add the following sentence at the end of Section 10.6 - Governing Law:

> NOTWITHSTANDING THE FOREGOING, IN RESPECT OF THE APPLICABILITY OF THE ACT AS HEREIN PROVIDED, THE LAWS OF THE STATE OF ____________[2] SHALL APPLY.

---

[2] Insert relevant state for Governmental Entity or Public Power System.

## SCHEDULE P: PRODUCTS AND RELATED DEFINITIONS

"Ancillary Services" means any of the services identified by a Transmission Provider in its transmission tariff as "ancillary services" including, but not limited to, regulation and frequency response, energy imbalance, operating reserve-spinning and operating reserve-supplemental, as may be specified in the Transaction.

"Capacity" has the meaning specified in the Transaction.

"Energy" means three-phase, 60-cycle alternating current electric energy, expressed in megawatt hours.

"Firm (LD)" means, with respect to a Transaction, that either Party shall be relieved of its obligations to sell and deliver or purchase and receive without liability only to the extent that, and for the period during which, such performance is prevented by Force Majeure. In the absence of Force Majeure, the Party to which performance is owed shall be entitled to receive from the Party which failed to deliver/receive an amount determined pursuant to Article Four.

"Firm Transmission Contingent - Contract Path" means, with respect to a Transaction, that the performance of either Seller or Buyer (as specified in the Transaction) shall be excused, and no damages shall be payable including any amounts determined pursuant to Article Four, if the transmission for such Transaction is interrupted or curtailed and (i) such Party has provided for firm transmission with the transmission provider(s) for the Product in the case of the Seller from the generation source to the Delivery Point or in the case of the Buyer from the Delivery Point to the ultimate sink, and (ii) such interruption or curtailment is due to "force majeure" or "uncontrollable force" or a similar term as defined under the applicable transmission provider's tariff. This contingency shall excuse performance for the duration of the interruption or curtailment notwithstanding the provisions of the definition of "Force Majeure" in Section 1.23 to the contrary.

"Firm Transmission Contingent - Delivery Point" means, with respect to a Transaction, that the performance of either Seller or Buyer (as specified in the Transaction) shall be excused, and no damages shall be payable including any amounts determined pursuant to Article Four, if the transmission to the Delivery Point (in the case of Seller) or from the Delivery Point (in the case of Buyer) for such Transaction is interrupted or curtailed and (i) such Party has provided for firm transmission with the transmission provider(s) for the Product, in the case of the Seller, to be delivered to the Delivery Point or, in the case of Buyer, to be received at the Delivery Point and (ii) such interruption or curtailment is due to "force majeure" or "uncontrollable force" or a similar term as defined under the applicable transmission provider's tariff. This transmission contingency excuses performance for the duration of the interruption or curtailment, notwithstanding the provisions of the definition of "Force Majeure" in Section 1.23 to the contrary. Interruptions or curtailments of transmission other than the transmission either immediately to or from the Delivery Point shall not excuse performance

"Firm (No Force Majeure)" means, with respect to a Transaction, that if either Party fails to perform its obligation to sell and deliver or purchase and receive the Product, the Party to which performance is owed shall be entitled to receive from the Party which failed to perform an amount determined pursuant to Article Four. Force Majeure shall not excuse performance of a Firm (No Force Majeure) Transaction.

"Into ______________ (the "Receiving Transmission Provider"), Seller's Daily Choice" means that, in accordance with the provisions set forth below, (1) the Product shall be scheduled and delivered to an interconnection or interface ("Interface") either (a) on the Receiving Transmission Provider's transmission system border or (b) within the control area of the Receiving Transmission Provider if the Product is from a source of generation in that control area, which Interface, in either case, the Receiving Transmission Provider identifies as available for delivery of the Product in or into its control area; and (2) Seller has the right on a daily prescheduled basis to designate the Interface where the Product shall be delivered. An "Into" Product shall be subject to the following provisions:

1. Prescheduling and Notification. Subject to the provisions of Section 6, not later than the prescheduling deadline of 11:00 a.m. CPT on the Business Day before the next delivery day or as otherwise agreed to by Buyer and Seller, Seller shall notify Buyer ("Seller's Notification") of Seller's immediate upstream counterparty and the Interface (the "Designated Interface") where Seller shall deliver the Product for the next delivery day, and Buyer shall notify Seller of Buyer's immediate downstream counterparty.

2. Availability of "Firm Transmission" to Buyer at Designated Interface; "Timely Request for Transmission," "ADI" and "Available Transmission." In determining availability to Buyer of next-day firm transmission ("Firm Transmission") from the Designated Interface, a "Timely Request for Transmission" shall mean a properly completed request for Firm Transmission made by Buyer in accordance with the controlling tariff procedures, which request shall be submitted to the Receiving Transmission Provider no later than 30 minutes after delivery of Seller's Notification, provided, however, if the Receiving Transmission Provider is not accepting requests for Firm Transmission at the time of Seller's Notification, then such request by Buyer shall be made within 30 minutes of the time when the Receiving Transmission Provider first opens thereafter for purposes of accepting requests for Firm Transmission.

Pursuant to the terms hereof, delivery of the Product may under certain circumstances be redesignated to occur at an Interface other than the Designated Interface (any such alternate designated interface, an "ADI") either (a) on the Receiving Transmission Provider's transmission system border or (b) within the control area of the Receiving Transmission Provider if the Product is from a source of generation in that control area, which ADI, in either case, the Receiving Transmission Provider identifies as available for delivery of the Product in or into its control area using either firm or non-firm transmission, as available on a day-ahead or hourly basis (individually or collectively referred to as "Available Transmission") within the Receiving Transmission Provider's transmission system.

3. Rights of Buyer and Seller Depending Upon Availability of/Timely Request for Firm Transmission.

A. Timely Request for Firm Transmission made by Buyer, Accepted by the Receiving Transmission Provider and Purchased by Buyer. If a Timely Request for Firm Transmission is made by Buyer and is accepted by the Receiving Transmission Provider and Buyer purchases such Firm Transmission, then Seller shall deliver and Buyer shall receive the Product at the Designated Interface.

i. If the Firm Transmission purchased by Buyer within the Receiving Transmission Provider's transmission system from the Designated Interface ceases to be available to Buyer for any reason, or if Seller is unable to deliver the Product at the Designated Interface for any reason except Buyer's non-performance, then at Seller's choice from among the following, Seller shall: (a) to the extent Firm Transmission is available to Buyer from an ADI on a day-ahead basis, require Buyer to purchase such Firm Transmission from such ADI, and schedule and deliver the affected portion of the Product to such ADI on the basis of Buyer's purchase of Firm Transmission, or (b) require Buyer to purchase non-firm transmission, and schedule and deliver the affected portion of the Product on the basis of Buyer's purchase of non-firm transmission from the Designated Interface or an ADI designated by Seller, or (c) to the extent firm transmission is available on an hourly basis, require Buyer to purchase firm transmission, and schedule and deliver the affected portion of the Product on the basis of Buyer's purchase of such hourly firm transmission from the Designated Interface or an ADI designated by Seller.

ii. If the Available Transmission utilized by Buyer as required by Seller pursuant to Section 3A(i) ceases to be available to Buyer for any reason, then Seller shall again have those alternatives stated in Section 3A(i) in order to satisfy its obligations.

iii. Seller's obligation to schedule and deliver the Product at an ADI is subject to Buyer's obligation referenced in Section 4B to cooperate reasonably therewith. If Buyer and Seller cannot complete the scheduling and/or delivery at an ADI, then Buyer shall be deemed to have satisfied its receipt obligations to Seller and Seller shall be deemed to have failed its delivery obligations to Buyer, and Seller shall be liable to Buyer for amounts determined pursuant to Article Four.

iv. In each instance in which Buyer and Seller must make alternative scheduling arrangements for delivery at the Designated Interface or an ADI pursuant to Sections 3A(i) or (ii), and Firm Transmission had been purchased by both Seller and Buyer into and within the Receiving Transmission Provider's transmission system as to the scheduled delivery which could not be completed as a result of the interruption or curtailment of such Firm Transmission, Buyer and Seller shall bear their respective transmission expenses and/or associated congestion charges incurred in connection with efforts to complete delivery by such alternative scheduling and delivery arrangements. In any instance except as set forth in the immediately preceding sentence, Buyer and Seller must make alternative scheduling arrangements for delivery at the Designated Interface or an ADI under Sections 3A(i) or (ii), Seller shall be responsible for any additional transmission purchases and/or associated congestion charges incurred by Buyer in connection with such alternative scheduling arrangements.

B. Timely Request for Firm Transmission Made by Buyer but Rejected by the Receiving Transmission Provider. If Buyer's Timely Request for Firm Transmission is rejected by the Receiving Transmission Provider because of unavailability of Firm Transmission from the Designated Interface, then Buyer shall notify Seller within 15 minutes after receipt of the Receiving Transmission Provider's notice of rejection ("Buyer's Rejection Notice"). If Buyer timely notifies Seller of such unavailability of Firm Transmission from the Designated Interface, then Seller shall be obligated either (1) to the extent Firm Transmission is available to Buyer from an ADI on a day-ahead basis, to require Buyer to purchase (at Buyer's own expense) such Firm Transmission from such ADI and schedule and deliver the Product to such ADI on the basis of Buyer's purchase of Firm Transmission, and thereafter the provisions in Section 3A shall apply, or (2) to require Buyer to purchase (at Buyer's own expense) non-firm transmission, and schedule and deliver the Product on the basis of Buyer's purchase of non-firm transmission from the Designated Interface or an ADI designated by the Seller, in which case Seller shall bear the risk of interruption or curtailment of the non-firm transmission; provided, however, that if the non-firm transmission is interrupted or curtailed or if Seller is unable to deliver the Product for any reason, Seller shall have the right to schedule and deliver the Product to another ADI in order to satisfy its delivery obligations, in which case Seller shall be responsible for any additional transmission purchases and/or associated congestion charges incurred by Buyer in connection with Seller's inability to deliver the Product as originally prescheduled. If Buyer fails to timely notify Seller of the unavailability of Firm Transmission, then Buyer shall bear the risk of interruption or curtailment of transmission from the Designated Interface, and the provisions of Section 3D shall apply.

C. Timely Request for Firm Transmission Made by Buyer, Accepted by the Receiving Transmission Provider and not Purchased by Buyer. If Buyer's Timely Request for Firm Transmission is accepted by the Receiving Transmission Provider but Buyer elects to purchase non-firm transmission rather than Firm Transmission to take delivery of the Product, then Buyer shall bear the risk of interruption or curtailment of transmission from the Designated Interface. In such circumstances, if Seller's delivery is interrupted as a result of transmission relied upon by Buyer from the Designated Interface, then Seller shall be deemed to have satisfied its delivery obligations to Buyer, Buyer shall be deemed to have failed to receive the Product and Buyer shall be liable to Seller for amounts determined pursuant to Article Four.

D. No Timely Request for Firm Transmission Made by Buyer, or Buyer Fails to Timely Send Buyer's Rejection Notice. If Buyer fails to make a Timely Request for Firm Transmission or Buyer fails to timely deliver Buyer's Rejection Notice, then Buyer shall bear the risk of interruption or curtailment of transmission from the Designated Interface. In such circumstances, if Seller's delivery is interrupted as a result of transmission relied upon by Buyer from the Designated Interface, then Seller shall be deemed to have satisfied its delivery obligations to Buyer, Buyer shall be deemed to have failed to receive the Product and Buyer shall be liable to Seller for amounts determined pursuant to Article Four.

4. Transmission.

A. Seller's Responsibilities. Seller shall be responsible for transmission required to deliver the Product to the Designated Interface or ADI, as the case may be. It is expressly agreed that Seller is not required to utilize Firm Transmission for its delivery obligations hereunder, and Seller shall bear the risk of utilizing non-firm transmission. If Seller's scheduled delivery to Buyer is interrupted as a result of Buyer's attempted transmission of the Product beyond the Receiving Transmission Provider's system border, then Seller will be deemed to have satisfied its delivery obligations to Buyer, Buyer shall be deemed to have failed to receive the Product and Buyer shall be liable to Seller for damages pursuant to Article Four.

B. Buyer's Responsibilities. Buyer shall be responsible for transmission required to receive and transmit the Product at and from the Designated Interface or ADI, as the case may be, and except as specifically provided in Section 3A and 3B, shall be responsible for any costs associated with transmission therefrom. If Seller is attempting to complete the designation of an ADI as a result of Seller's rights and obligations hereunder, Buyer shall co-operate reasonably with Seller in order to effect such alternate designation.

5. Force Majeure. An "Into" Product shall be subject to the "Force Majeure" provisions in Section 1.23.

6. Multiple Parties in Delivery Chain Involving a Designated Interface. Seller and Buyer recognize that there may be multiple parties involved in the delivery and receipt of the Product at the Designated Interface or ADI to the extent that (1) Seller may be purchasing the Product from a succession of other sellers ("Other Sellers"), the first of which Other Sellers shall be causing the Product to be generated from a source ("Source Seller") and/or (2) Buyer may be selling the Product to a succession of other buyers ("Other Buyers"), the last of which Other Buyers shall be using the Product to serve its energy needs ("Sink Buyer"). Seller and Buyer further recognize that in certain Transactions neither Seller nor Buyer may originate the decision as to either (a) the original identification of the Designated Interface or ADI (which designation may be made by the Source Seller) or (b) the Timely Request for Firm Transmission or the purchase of other Available Transmission (which request may be made by the Sink Buyer). Accordingly, Seller and Buyer agree as follows:

A. If Seller is not the Source Seller, then Seller shall notify Buyer of the Designated Interface promptly after Seller is notified thereof by the Other Seller with whom Seller has a contractual relationship, but in no event may such designation of the Designated Interface be later than the prescheduling deadline pertaining to the Transaction between Buyer and Seller pursuant to Section 1.

B. If Buyer is not the Sink Buyer, then Buyer shall notify the Other Buyer with whom Buyer has a contractual relationship of the Designated Interface promptly after Seller notifies Buyer thereof, with the intent being that the party bearing actual responsibility to secure transmission shall have up to 30 minutes after receipt of the Designated Interface to submit its Timely Request for Firm Transmission.

C. Seller and Buyer each agree that any other communications or actions required to be given or made in connection with this "Into Product" (including without limitation, information relating to an ADI) shall be made or taken promptly after receipt of the relevant information from the Other Sellers and Other Buyers, as the case may be.

D. Seller and Buyer each agree that in certain Transactions time is of the essence and it may be desirable to provide necessary information to Other Sellers and Other Buyers in order to complete the scheduling and delivery of the Product. Accordingly, Seller and Buyer agree that each has the right, but not the obligation, to provide information at its own risk to Other Sellers and Other Buyers, as the case may be, in order to effect the prescheduling, scheduling and delivery of the Product

"Native Load" means the demand imposed on an electric utility or an entity by the requirements of retail customers located within a franchised service territory that the electric utility or entity has statutory obligation to serve.

"Non-Firm" means, with respect to a Transaction, that delivery or receipt of the Product may be interrupted for any reason or for no reason, without liability on the part of either Party.

"System Firm" means that the Product will be supplied from the owned or controlled generation or pre-existing purchased power assets of the system specified in the Transaction (the "System") with non-firm transmission to and from the Delivery Point, unless a different Transmission Contingency is specified in a Transaction. Seller's failure to deliver shall be excused: (i) by an event or circumstance which prevents Seller from performing its obligations, which event or circumstance was not anticipated as of the date the Transaction was agreed to, which is not within the reasonable control of, or the result of the negligence of, the Seller; (ii) by Buyer's failure to perform; (iii) to the extent necessary to preserve the integrity of, or prevent or limit any instability on, the System; (iv) to the extent the System or the control area or reliability council within which the System operates declares an emergency condition, as determined in the system's, or the control area's, or reliability council's reasonable judgment; or (v) by the interruption or curtailment of transmission to the Delivery Point or by the occurrence of any Transmission Contingency specified in a Transaction as excusing Seller's performance. Buyer's failure to receive shall be excused (i) by Force Majeure; (ii) by Seller's failure to perform, or (iii) by the interruption or curtailment of transmission from the Delivery Point or by the occurrence of any Transmission Contingency specified in a Transaction as excusing Buyer's performance. In any of such events, neither party shall be liable to the other for any damages, including any amounts determined pursuant to Article Four.

"Transmission Contingent" means, with respect to a Transaction, that the performance of either Seller or Buyer (as specified in the Transaction) shall be excused, and no damages shall be payable including any amounts determined pursuant to Article Four, if the transmission for such Transaction is unavailable or interrupted or curtailed for any reason, at any time, anywhere from the Seller's proposed generating source to the Buyer's proposed ultimate sink, regardless of whether transmission, if any, that such Party is attempting to secure and/or has purchased for the Product is firm or non-firm. If the transmission (whether firm or non-firm) that Seller or Buyer is attempting to secure is from source to sink is unavailable, this contingency excuses performance for the entire Transaction. If the transmission (whether firm or non-firm) that Seller or Buyer has secured from source to sink is interrupted or curtailed for any reason, this contingency excuses performance for the duration of the interruption or curtailment notwithstanding the provisions of the definition of "Force Majeure" in Article 1.23 to the contrary.

"Unit Firm" means, with respect to a Transaction, that the Product subject to the Transaction is intended to be supplied from a generation asset or assets specified in the Transaction. Seller's failure to deliver under a "Unit Firm" Transaction shall be excused: (i) if the specified generation asset(s) are unavailable as a result of a Forced Outage (as defined in the NERC Generating Unit Availability Data System (GADS) Forced Outage reporting guidelines) or (ii) by an event or circumstance that affects the specified generation asset(s) so as to prevent Seller from performing its obligations, which event or circumstance was not anticipated as of the date the Transaction was agreed to, and which is not within the reasonable control of, or the result of the negligence of, the Seller or (iii) by Buyer's failure to perform. In any of such events, Seller shall not be liable to Buyer for any damages, including any amounts determined pursuant to Article Four.

**EXHIBIT A**

**MASTER POWER PURCHASE AND SALE AGREEMENT**
**CONFIRMATION LETTER**

This confirmation letter shall confirm the Transaction agreed to on ___________, ___ between __________________________ ("Party A") and _____________________ ("Party B") regarding the sale/purchase of the Product under the terms and conditions as follows:

Seller: ______________________________________________________________________

Buyer: ______________________________________________________________________

Product:

[] Into _________________, Seller's Daily Choice

[] Firm (LD)

[] Firm (No Force Majeure)

[] System Firm

(Specify System: _________________________________________________________)

[] Unit Firm

(Specify Unit(s): _________________________________________________________)

[] Other ______________________________________________________________

[] Transmission Contingency (If not marked, no transmission contingency)

| | | | | | |
|---|---|---|---|---|---|
| [] | FT-Contract Path Contingency | [] | Seller | [] | Buyer |
| [] | FT-Delivery Point Contingency | [] | Seller | [] | Buyer |
| [] | Transmission Contingent | [] | Seller | [] | Buyer |
| [] | Other transmission contingency | | | | |

(Specify: _______________________________________________________________)

Contract Quantity: ______________________________________________________________

Delivery Point: ________________________________________________________________

Contract Price:

Energy Price: _________________________________________________________________

Other Charges: ________________________________________________________________

Delivery Period: ______________________________

Special Conditions: ______________________________

Scheduling: ______________________________

Option Buyer: ______________________________

Option Seller: ______________________________

Type of Option: ______________________________

Strike Price: ______________________________

Premium: ______________________________

Exercise Period: ______________________________

This confirmation letter is being provided pursuant to and in accordance with the Master Power Purchase and Sale Agreement dated _____________ (the "Master Agreement") between Party A and Party B, and constitutes part of and is subject to the terms and provisions of such Master Agreement. Terms used but not defined herein shall have the meanings ascribed to them in the Master Agreement.

| [Party A] | [Party B] |
|---|---|
| Name: ____________________ | Name: ____________________ |
| Title: ____________________ | Title: ____________________ |
| Phone No: ____________________ | Phone No: ____________________ |
| Fax: ____________________ | Fax: ____________________ |

**PG&E Gas and Electric**
**Advice Filing List**
**General Order 96-B, Section IV**

Alcantar & Kahl
Ameresco
Anderson & Poole
Arizona Public Service Company
BART
BP Energy Company
Barkovich & Yap, Inc.
Bartle Wells Associates
C & H Sugar Co.
CA Bldg Industry Association
CAISO
CLECA Law Office
CSC Energy Services
California Cotton Ginners & Growers Assn
California Energy Commission
California League of Food Processors
California Public Utilities Commission
Calpine
Cameron McKenna
Cardinal Cogen
Casner, Steve
Chamberlain, Eric
Chevron Company
Chris, King
City of Glendale
City of Palo Alto
Clean Energy Fuels
Coast Economic Consulting
Commerce Energy
Commercial Energy
Consumer Federation of California
Crossborder Energy
Davis Wright Tremaine LLP
Day Carter Murphy
Defense Energy Support Center
Department of Water Resources
Department of the Army
Dept of General Services
Division of Business Advisory Services
Douglas & Liddell
Douglass & Liddell
Downey & Brand
Duke Energy
Dutcher, John
Ellison Schneider & Harris LLP
FPL Energy Project Management, Inc.
Foster Farms
G. A. Krause & Assoc.
GLJ Publications
Goodin, MacBride, Squeri, Schlotz & Ritchie
Green Power Institute
Hanna & Morton
Hitachi
International Power Technology
Intestate Gas Services, Inc.
Los Angeles Dept of Water & Power
Luce, Forward, Hamilton & Scripps LLP
MBMC, Inc.
MRW & Associates
Manatt Phelps Phillips
Matthew V. Brady & Associates
McKenzie & Associates
Merced Irrigation District
Mirant
Modesto Irrigation District
Morgan Stanley
Morrison & Foerster
New United Motor Mfg., Inc.
Norris & Wong Associates
North Coast SolarResources
Northern California Power Association
Occidental Energy Marketing, Inc.
OnGrid Solar
Praxair
R. W. Beck & Associates
RCS, Inc.
Recon Research
SCD Energy Solutions
SCE
SMUD
SPURR
Santa Fe Jets
Seattle City Light
Sempra Utilities
Sierra Pacific Power Company
Silicon Valley Power
Southern California Edison Company
Sunshine Design
Sutherland, Asbill & Brennan
Tabors Caramanis & Associates
Tecogen, Inc.
Tiger Natural Gas, Inc.
Tioga Energy
TransCanada
Turlock Irrigation District
U S Borax, Inc.
United Cogen
Utility Cost Management
Utility Specialists
Verizon
Wellhead Electric Company
Western Manufactured Housing Communities Association (WMA)
eMeter Corporation