STATE OF CALIFORNIA EDMUND G. BROWN JR., *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

**Advice Letter: 4364-E**

February 5, 2015

Pacific Gas and Electric Company
Attention: Meredith Allen
Senior Director, Regulatory Relations
77 Beale Street, Mail Code B10C
San Francisco, CA 94177

**SUBJECT: PPA for Procurement of Eligible Renewable Energy Resources between Sand Hill Wind II, LLC and PG&E**

Dear Ms. Allen:

Advice Letter 4364-E is effective as of October 17, 2014, per Resolution E-4666 Ordering Paragraphs.

Sincerely,

Edward Randolph

Edward Randolph
Director, Energy Division

**Brian K. Cherry**
Vice President
Regulatory Relations

Pacific Gas and Electric Company
77 Beale St., Mail Code B10C
P.O. Box 770000
San Francisco, CA 94177

Fax: 415-973-7226

February 20, 2014

**Advice 4364-E**
(Pacific Gas and Electric Company ID U39 E)

Public Utilities Commission of the State of California

**Subject: Power Purchase Agreements for Procurement of Eligible Renewable Energy Resources between Sand Hill Wind II, LLC and Pacific Gas and Electric Company**

## I. Introduction

### A. Purpose of the advice letter

Pacific Gas and Electric Company ("PG&E") seeks California Public Utilities Commission ("Commission" or "CPUC") approval of two power purchase agreements ("PPAs"), each with an indirect subsidiary of Ogin, Inc. ("Ogin"), Sand Hill Wind II, LLC ("Sand Hill"). The counterparties are Sand Hill Wind II, LLC Altamont Project ("Altamont") and Sand Hill Wind II, LLC Dyer Road Project ("Dyer Road"). The PPAs are for Renewables Portfolio Standard ("RPS")-eligible energy from two adjacent planned repowered wind generation facilities located in Tracy, California. The PPAs have terms of 20 years and are expected to deliver a total of 53 gigawatt hours ("GWh") per year (22.8 GWh from Altamont and 30.2 GWh from Dyer Road).

PG&E requests that the Commission issue a resolution no later than September 11, 2014, approving the PPAs in their entirety and containing the findings as set forth in Section VI below.

### B. Identify the subject of the advice letter, including:

#### 1. Project name

The two projects are:

1. Altamont, an 8.6 megawatt ("MW") wind facility located in Tracy, California;
2. Dyer Road, an 11.4 MW wind facility located in Tracy, California.

The projects are adjacent to each other and share the same characteristics but have separate interconnection points.

PG&E refers to the two projects collectively as the “Projects” or individually as a “Project” in this Advice Letter.

**2. Technology (including level of maturity)**

The Projects will use Ogin’s patented Mixer Ejector Wind Turbine (“MEWT”) technology, which Ogin claims is a compact, robust, high-efficiency, low-cost shrouded design utilizing mature aerospace technology. This technology is developmental for wind turbine applications, with limited demonstration units operating in the field. Ogin has asserted that this technology is expected to result in less avian mortality. In Phase I of the Projects, this hypothesis will be tested through a research study funded by the California Energy Commission (“CEC”). These Projects are among the first commercial deployments of the technology.

**3. General Location and Interconnection Point**

Both Projects are located in the Altamont Pass Wind Resource Area in Alameda County, California. The Altamont and Dyer Road Projects are co-located and interconnect to two different substations, the Altamont Midway Substation and the Dyer Road Substation, respectively. The interconnection points are within the boundaries of the California Independent System Operator (“CAISO”), a California balancing authority.

**4. Owner(s) / Developer(s)**

**a. Name(s)**

The Projects are organized under one company, which is a Delaware limited liability company called Sand Hill Wind II, LLC. Sand Hill Wind II, LLC is a wholly-owned subsidiary of Sand Hill Wind, LLC, which in turn is a wholly-owned subsidiary of New Dimension Energy Company, LLC (“NDEC”), which is the developer of the Projects. NDEC is a subsidiary of Ogin, which is a development stage company that develops, manufactures and sells wind turbines to companies and organizations engaged in electrical power generation.

**b. Type of entity(ies) (e.g. LLC, partnership)**

The owner of the Projects is a LLC.

**c. Business Relationship (if applicable, between seller/owner/developer)**

See response to Section I.B.4.a above.

**5. Project background, e.g., expiring QF contract, phased project, previous power purchase agreement, contract amendment**

The Projects entail the repowering of operational wind qualifying facilities (“QF”). After expiration of the QF contracts in 2015, the existing wind turbines and related equipment will be removed and are planned to be replaced with new Ogin wind turbines.

**6. Source of agreement, i.e., RPS solicitation year or bilateral negotiation**

The PPAs resulted from PG&E's 2012 RPS Solicitation.

**7. If an amendment, describe contract terms being amended and reason for amendment**

Not applicable.

## C. General Project(s) Description

| | | |
|---|---|---|
| Project Name | Sand Hill Wind II – Altamont | Sand Hill Wind II – Dyer Road |
| Technology | Wind | Wind |
| Capacity (MW) | 8.6 MW | 11.4 MW |
| Capacity Factor | 30.1% | 30.1% |
| Expected Generation (GWh/Year) | 22.8 GWh | 30.2 GWh |
| Initial Commercial Operational Date | April 1, 2020 | April 1, 2020 |
| Date contract Delivery Term begins | The Project will begin delivering to PG&E on April 1, 2020. | The Project will begin delivering to PG&E on April 1, 2020. |
| Delivery Term (Years) | 20 | 20 |
| Vintage (New / Existing / Repower) | Repower | Repower |
| Location (city and state) | Tracy, California | Tracy, California |
| Control Area (e.g., CAISO, BPA) | CAISO | CAISO |
| Nearest Competitive Renewable Energy Zone (CREZ) as identified by the Renewable Energy Transmission Initiative (RETI)[1] | Solano | Solano |
| Type of cooling, if applicable | Not Applicable | Not Applicable |

[1] Information about RETI is available at: http://www.energy.ca.gov/reti/

**D. Project location**

**1. Provide a general map of the generation facility's location.**


The Projects are adjacent to each other as shown in the map above.

**2. For new projects describe facility's current land use type (private, agricultural, county, state lands (agency), federal lands (agency), etc.).**

The Projects will be sited on active, privately-owned grazing land that has an existing wind farm.

**E. General Deal Structure**

**Describe general characteristics of contract, for example:**

**1. Required or expected Portfolio Content Category of the proposed contract**

The Projects are two wind generation facilities, totaling 20 MW, which plan to use existing interconnection facilities to interconnect to the CAISO-controlled transmission system, a California balancing authority. Because the Projects are RPS-eligible generators that expect to have their first point of interconnection with the Western Electricity Coordinating Council ("WECC") transmission system within the boundaries of a California balancing authority, the RPS-eligible procurement from the Projects satisfy the criteria for the portfolio content category specified in Public Utilities Code Section 399.16(b) (1) (A) (hereinafter "Portfolio Content Category One").

**2. Partial/full generation output of facility**

PG&E will receive all of the generation output from the Projects starting April 1, 2020. The PPAs are for the purchase of an as-available product ("Product").

**3. Any additional products, e.g. capacity**

The Product includes the energy, capacity, and all ancillary products, services or attributes which are or can be produced by or associated with the Projects, including, without limitation, Renewable Energy Credits ("RECs"), Capacity Attributes and Green Attributes.

**4. Generation delivery point (e.g. busbar, hub, etc.)**

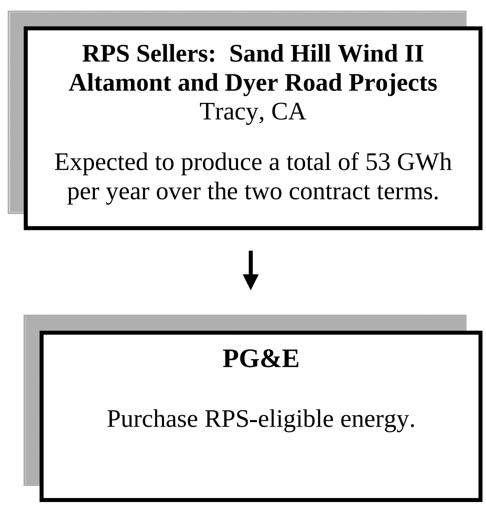
The PPAs require the Projects' energy to be delivered to the PNode designated by the CAISO. The delivery market is NP-15.

**5. Energy management (e.g. firm/shape, scheduling, selling, etc.)**

There is no firming or shaping associated with these PPAs. PG&E or its agent will be the Scheduling Coordinator for the Projects.

**6. Diagram and explanation of delivery structure**

**Figure 1: Delivery Structure of the PPAs**




## F. RPS Statutory Goals & Requirements

**1. Briefly describe the Project's consistency with and contribution towards the RPS program's statutory goals set forth in Public Utilities Code §399.11. These goals include displacing fossil fuel consumption within the state; adding new electrical generating facilities within WECC; reducing air**

**pollution in the state; meeting the state's climate change goals by reducing emissions of greenhouse gases associated with electrical generation; promoting stable retail rates for electric service; a diversified and balanced energy generation portfolio; meeting the state's resource adequacy requirements; safe and reliable operation of the electrical grid; and implementing the state's transmission and land use planning activities.**

Public Utilities Code Section 399.11 states that increasing California's reliance on eligible renewable energy resources is intended to displace fossil fuel consumption within the state, promote stable electricity prices, reduce greenhouse gas ("GHG") emissions, improve environmental quality and promote the goal of a diversified and balanced energy generation portfolio. The Projects are consistent with these goals because they will be repowered wind generation facilities located in the WECC that will generate clean energy and will produce little, if any, GHG emissions directly associated with energy production.

**2. Describe how procurement pursuant to the contract will meet IOU's specific RPS compliance period needs. Include Renewable Net Short calculation as part of response.**

Senate Bill ("SB") 1078 established the California RPS Program, requiring an electrical corporation to increase its use of eligible renewable energy resources to twenty 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 April 2011, Governor Brown signed into law SB 2 1X. As implemented by D.11-12-020, SB 2 1X requires retail sellers of electricity to meet the following RPS procurement quantity requirements beginning on January 1, 2011:

- An average of twenty percent of the combined bundled retail sales during the first compliance period (2011-2013).
- Sufficient procurement during the second compliance period (2014-2016) that is consistent with the following formula: (.217 * 2014 retail sales) + (.233 * 2015 retail sales) + (.25 * 2016 retail sales).
- Sufficient procurement during the third compliance period (2017-2020) that is consistent with the following formula: (.27 * 2017 retail sales) + (.29 * 2018 retail sales) + (.31 * 2019 retail sales) + (.33 * 2020 retail sales).
- 33 percent of bundled retail sales in 2021 and all years thereafter.

Consistent with the Energy Division Staff methodology for calculating the renewable net short ("RNS")[2], PG&E provides a RNS calculation in Table 1. PG&E also provides an alternative RNS calculation (the "Alternate RNS") in Table 2. The RNS calculates the volumes that PG&E projects it will need for RPS compliance based on direction provided in the August 2, 2012 Ruling using an "expected case" scenario. The Alternate RNS provides the same calculations as the RNS but substitutes PG&E's internal long-term

[2] *See* Administrative Law Judge's Ruling (1) Adopting Renewable Net Short Calculation Methodology (2) Incorporating the Attached Methodology into the Record, and (3) Extending the Date for Filing Updates to 2012 Procurement Plans issued on August 2, 2012.

bundled retail sales forecast for the assumptions provided in the August 2, 2012 ALJ Ruling.

As illustrated by both scenarios, PG&E's existing RPS portfolio is expected to provide sufficient RPS-eligible deliveries to meet PG&E's RPS compliance requirements in the first compliance period (2011 – 2013). Additionally, PG&E expects to exceed the RPS procurement requirement in the second compliance period (2014 – 2016). While the RNS calculations show a slight surplus in the third compliance period, both scenarios show that if RPS-eligible projects in PG&E's portfolio perform as expected, PG&E has fairly significant incremental need beginning in 2020 (prior to applying any excess procurement from earlier compliance periods) and beyond in order to maintain a thirty-three percent RPS level. This significantly increased need in the early part of the next decade is driven, primarily, by a large volume of expiring contracts in that timeframe.

Deliveries to PG&E under the PPAs will commence on April 1, 2020. Total deliveries from the Projects are expected to average 53 GWh per year. The PPAs will therefore contribute toward PG&E's RPS procurement requirements at the end of the third compliance period and beyond when PG&E has a need for new incremental deliveries of RPS-eligible power.

# Table 1: Renewable Net Short Calculation as of December 2013

## Net Short Calculation Using PG&E Bundled Retail Sales Forecast In Near Term (2013 - 2017) and LTPP Methodology (2018 - 2030)**

### Current Expected Need Scenario (Annual)

| Line # | | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | RPS Target | 20.0% | 20.0% | 20.0% | 21.7% | 23.3% | 25.0% | 27% | 29% | 31% | 33% | 33% | 33% | 33% | 33% | 33% | 33% | 33% | 33% | 33% | 33% |
| 2 | Voluntary Margin of Over-Procurement (GWh)*** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 3 | Aggregate Volumes (GWh) | 14,833 | 14,511 | 17,167 | 22,054 | 23,723 | 24,048 | 25,375 | 24,354 | 23,881 | 23,265 | 22,820 | 20,485 | 20,151 | 19,887 | 19,763 | 19,158 | 18,823 | 18,713 | 18,104 | 18,037 |
| 4 | Annual RPS Position (%) | 19.8% | 19.0% | [redacted] | | | | 32.2% | 31.8% | 31.1% | 30.2% | 29.6% | 26.5% | 26.0% | 25.6% | 25.4% | 24.6% | 24.1% | 23.9% | 23.1% | 23.0% |
| 5 | Gross Surplus/(Deficit) compared to Annual Targets* (GWh) | (140) | (730) | | | | | 4,125 | 2,139 | 107 | (2,132) | (2,626) | (5,013) | (5,397) | (5,713) | (5,888) | (6,545) | (6,931) | (7,092) | (7,753) | (7,872) |
| 6 | Non-Bankable Volumes (GWh) | 0 | 15 | | | | | 89 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7 | Volumes (Banked) or Withdrawn from Bank (GWh) | 0 | 0 | | | | | (4,037) | (2,139) | (107) | 2,132 | 2,626 | 5,013 | 5,397 | 5,713 | 2,209 | 0 | 0 | 0 | 0 | 0 |
| 8 | Net Surplus/(Deficit) (GWh) | (140) | (730) | | | | | 89 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (3,678) | (6,545) | (6,931) | (7,092) | (7,753) | (7,872) |
| 9 | Net Annual RPS Positions (%) with Use of Bank | 19.8% | 19.0% | | | | | 27.1% | 29.0% | 31.0% | 33.0% | 33.0% | 33.0% | 33.0% | 33.0% | 28.3% | 24.6% | 24.1% | 23.9% | 23.1% | 23.0% |
| 10 | Cumulative Banked Volumes (GWh) | 0 | 0 | | | | 16,808 | 20,845 | 22,984 | 23,091 | 20,959 | 18,332 | 13,320 | 7,923 | 2,209 | 0 | 0 | 0 | 0 | 0 | 0 |
| 11 | Forecast Failure Rate (%) for New Projects not yet online | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 12 | Forecast Failure Rate (%) for Existing Generation | 0.0% | 0.0% | 0.1% | 0.7% | 0.5% | 0.4% | 0.4% | 0.3% | 0.2% | 0.1% | 0.0% | 0.1% | 0.1% | 0.1% | 0.1% | 0.1% | 0.1% | 0.1% | 0.1% | 0.1% |

### Current Expected Need Scenario (Compliance Period)

| Line # | | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 13 | Compliance Period Requirement | | 20.0% | | | 23.3% | | | 30.0% | | | 33% | 33% | 33% | 33% | 33% | 33% | 33% | 33% | 33% | 33% |
| 14 | Voluntary Margin of Over-Procurement (GWh)*** | | 0 | | | 0 | | | 0 | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 15 | Aggregate Volumes (GWh) | | 46,511 | | | 69,826 | | | 96,874 | | | 22,820 | 20,485 | 20,151 | 19,887 | 19,763 | 19,158 | 18,823 | 18,713 | 18,104 | 18,037 |
| 16 | RPS Position (%) | [redacted] | | | | | | | 31.4% | | | 29.6% | 26.5% | 26.0% | 25.6% | 25.4% | 24.6% | 24.1% | 23.9% | 23.1% | 23.0% |
| 17 | Gross Surplus/(Deficit) (GWh) | | | | | | | | 4,239 | | | (2,626) | (5,013) | (5,397) | (5,713) | (5,888) | (6,545) | (6,931) | (7,092) | (7,753) | (7,872) |
| 18 | Non-Bankable Volumes (GWh) | | | | | | | | 89 | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 19 | Volumes (Banked) or Withdrawn from Bank (GWh) | | | | | | | | (4,151) | | | 2,626 | 5,013 | 5,397 | 5,713 | 2,209 | 0 | 0 | 0 | 0 | 0 |
| 20 | Net Surplus/(Deficit) (GWh) | | | | | | | | 89 | | | 0 | 0 | 0 | 0 | (3,678) | (6,545) | (6,931) | (7,092) | (7,753) | (7,872) |
| 21 | Net RPS Positions (%) | | | | | | | | 30.0% | | | 33.0% | 33.0% | 33.0% | 33.0% | 28.3% | 24.6% | 24.1% | 23.9% | 23.1% | 23.0% |
| 22 | Cumulative Banked Volumes (GWh) | | | | | 16,808 | | | 20,959 | | | 18,332 | 13,320 | 7,923 | 2,209 | 0 | 0 | 0 | 0 | 0 | 0 |
| 23 | Forecast Failure Rate (%) for New Projects not yet online | | 0% | | | 0% | | | 0% | | | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 24 | Forecast Failure Rate (%) for Existing Generation | | 0.0% | | | 0.5% | | | 0.3% | | | 0.0% | 0.1% | 0.1% | 0.1% | 0.1% | 0.1% | 0.1% | 0.1% | 0.1% | 0.1% |

| | | |
|---|---|---|
| 25 | Total RPS Risk Adjusted Net Short (2011-2030) (GWh) | (39,870) |

* Assumed annual targets are: 2011-2013 (20% annually), 2014 (21.7%), 2015 (23.3%), 2016 (25%), 2017 (27%), 2018 (29%), 2019 (31%), and 2020 (33%). These targets are illustrative only and not enforceable.

** The 2010 LTPP sales forecast extends only from 2018 through 2020. For purposes of extending this forecast past 2020, PG&E applied a 0.2% annual growth rate to the LTPP's "Adjusted Energy Demand/Consumption" forecast in years after 2020. (This 0.2% growth rate is equal to the average growth rate seen in the LTPP forecast over the 2018-2020 period.) The "Energy Demand/Consumption" amount was then adjusted for line losses to determine bundled retail sales.

*** PG&E considers an adequate bank of surplus RPS procurement to be a voluntary margin of procurement. However, in accordance with Decision 13-11-024, PG&E will not seek in its 2013 RPS Solicitation to procure Portfolio Content Category 2 and 3 RPS products to build and maintain an adequate bank.

# Table 2: Alternate Renewable Net Short Calculation as of December 2013

**Net Short Calculation Using PG&E Bundled Retail Sales Forecast**

## Current Expected Need Scenario (Annual)

| Line # | | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | **RPS Target** | 20.0% | 20.0% | 20.0% | 21.7% | 23.3% | 25.0% | 27% | 29% | 31% | 33% | 33% | 33% | 33% | 33% | 33% | 33% | 33% | 33% | 33% | 33% |
| 2 | **Voluntary Margin of Over-Procurement (GWh)**** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 3 | **Aggregate Volumes (GWh)** | 14,833 | 14,511 | 17,167 | 22,054 | 23,723 | 24,048 | 25,375 | 24,354 | 23,881 | 23,265 | 22,820 | 20,485 | 20,151 | 19,887 | 19,763 | 19,158 | 18,823 | 18,713 | 18,104 | 18,037 |
| 4 | **Annual RPS Position (%)** | 19.8% | 19.0% | [redacted] | | | | 32.2% | 30.7% | 29.9% | 29.0% | 28.2% | 25.1% | 24.5% | 23.9% | 23.6% | 22.6% | 22.0% | 21.6% | 20.7% | 20.4% |
| 5 | **Gross Surplus/(Deficit) compared to Annual Targets* (GWh)** | (140) | (730) | | | | | 4,125 | 1,370 | (841) | (3,243) | (3,896) | (6,480) | (7,043) | (7,567) | (7,922) | (8,827) | (9,423) | (9,815) | (10,713) | (11,079) |
| 6 | **Non-Bankable Volumes (GWh)** | 0 | 15 | | | | | 89 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7 | **Volumes (Banked) or Withdrawn from Bank (GWh)** | 0 | 0 | | | | | (4,037) | (1,370) | 841 | 3,243 | 3,896 | 6,480 | 7,043 | 712 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | **Net Surplus/(Deficit) (GWh)** | (140) | (730) | | | | | 89 | 0 | 0 | 0 | 0 | 0 | 0 | (6,855) | (7,922) | (8,827) | (9,423) | (9,815) | (10,713) | (11,079) |
| 9 | **Net Annual RPS Positions (%) with Use of Bank** | 19.8% | 19.0% | | | | | 27.1% | 29.0% | 31.0% | 33.0% | 33.0% | 33.0% | 33.0% | 24.8% | 23.6% | 22.6% | 22.0% | 21.6% | 20.7% | 20.4% |
| 10 | **Cumulative Banked Volumes (GWh)** | 0 | 0 | | | | 16,808 | 20,845 | 22,215 | 21,374 | 18,131 | 14,235 | 7,755 | 712 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 11 | Forecast Failure Rate (%) for New Projects not yet online | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 12 | Forecast Failure Rate (%) for Existing Generation | 0.0% | 0.0% | 0.1% | 0.7% | 0.5% | 0.4% | 0.4% | 0.3% | 0.2% | 0.1% | 0.0% | 0.1% | 0.1% | 0.1% | 0.1% | 0.1% | 0.1% | 0.1% | 0.1% | 0.1% |

## Current Expected Need Scenario (Compliance Period)

| Line # | | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 13 | **Compliance Period Requirement** | | 20.0% | | | 23.3% | | | 30.0% | | | 33% | 33% | 33% | 33% | 33% | 33% | 33% | 33% | 33% | 33% |
| 14 | **Voluntary Margin of Over-Procurement (GWh)**** | | 0 | | | 0 | | | 0 | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 15 | **Aggregate Volumes (GWh)** | | 46,511 | | | 69,826 | | | 96,874 | | | 22,820 | 20,485 | 20,151 | 19,887 | 19,763 | 19,158 | 18,823 | 18,713 | 18,104 | 18,037 |
| 16 | **RPS Position (%)** | [redacted] | | | | | | | 30.5% | | | 28.2% | 25.1% | 24.5% | 23.9% | 23.6% | 22.6% | 22.0% | 21.6% | 20.7% | 20.4% |
| 17 | **Gross Surplus/(Deficit) (GWh)** | | | | | | | | 1,411 | | | (3,896) | (6,480) | (7,043) | (7,567) | (7,922) | (8,827) | (9,423) | (9,815) | (10,713) | (11,079) |
| 18 | **Non-Bankable Volumes (GWh)** | | | | | | | | 89 | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 19 | **Volumes (Banked) or Withdrawn from Bank (GWh)** | | | | | | | | (1,323) | | | 3,896 | 6,480 | 7,043 | 712 | 0 | 0 | 0 | 0 | 0 | 0 |
| 20 | **Net Surplus/(Deficit) (GWh)** | | | | | | | | 89 | | | 0 | 0 | 0 | (6,855) | (7,922) | (8,827) | (9,423) | (9,815) | (10,713) | (11,079) |
| 21 | **Net RPS Positions (%)** | | | | | | | | 30.0% | | | 33.0% | 33.0% | 33.0% | 24.8% | 23.6% | 22.6% | 22.0% | 21.6% | 20.7% | 20.4% |
| 22 | **Cumulative Banked Volumes (GWh)** | | | | | 16,808 | | | 18,131 | | | 14,235 | 7,755 | 712 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 23 | Forecast Failure Rate (%) for New Projects not yet online | | 0% | | | 0% | | | 0% | | | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 24 | Forecast Failure Rate (%) for Existing Generation | | 0.0% | | | 0.5% | | | 0.3% | | | 0.0% | 0.1% | 0.1% | 0.1% | 0.1% | 0.1% | 0.1% | 0.1% | 0.1% | 0.1% |

| Line # | | |
|---|---|---|
| 25 | Total RPS Risk Adjusted Net Short (2011-2030) (GWh) | (64,635) |

* Assumed annual targets are: 2011-2013 (20% annually), 2014 (21.7%), 2015 (23.3%), 2016 (25%), 2017 (27%), 2018 (29%), 2019 (31%), and 2020 (33%). These targets are illustrative only and not enforceable.

** PG&E considers an adequate bank of surplus RPS procurement to be a voluntary margin of procurement. However, in accordance with Decision 13-11-024, PG&E will not seek in its 2013 RPS Solicitation to procure Portfolio Content Category 2 and 3 RPS products to build and maintain an adequate bank.

### G. Confidentiality

**Explain if confidential treatment of specific material is requested. Describe the information and reason(s) for confidential treatment consistent with the showing required by D.06-06-066, as modified by D.08-04-023.**

In support of this Advice Letter, PG&E has provided the confidential information listed below. This information includes the PPAs 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.

**Confidential Attachments:**

**Appendix A – Consistency with Commission Decisions and Rules and Project Development Status**

**Appendix B – 2012 Solicitation Overview**

**Appendix C1 – Independent Evaluator Report (Confidential)**

**Appendix D – Contract Summary**

**Appendix E1 – Comparison of the Altamont PPA to PG&E's 2012 Pro Forma Power Purchase Agreement**

**Appendix E2 – Comparison of the Dyer Road PPA to PG&E's 2012 Pro Forma Power Purchase Agreement**

**Appendix F1 – Altamont Power Purchase Agreement**

**Appendix F2 – Dyer Road Power Purchase Agreement**

**Appendix G – Projects' Contributions Toward RPS Goals**

**Public Attachment**

**Appendix C2 – Independent Evaluator Report (Public)**

## II. Consistency with Commission Decisions

### A. RPS Procurement Plan

**1. Identify the Commission decision that approved the utility's RPS Procurement Plan. Did the utility adhere to Commission guidelines for filing and revisions?**

On November 14, 2012, the CPUC issued D.12-11-016, which conditionally approved PG&E's 2012 Renewable Procurement Plan ("2012 RPS Plan"). Consistent with the decision, PG&E submitted a final version of its 2012 RPS Plan on November 29, 2012. In this plan, PG&E stated that it seeks to procure about 1,000 GWh in its 2012 RPS Solicitation, with a preference for long-term contracts that qualify as a Portfolio Content Category One product with initial deliveries starting in 2019-2020.

**2. Describe the Procurement Plan's assessment of portfolio needs.**

The goal of PG&E's 2012 RPS Plan is to procure approximately 1,000 GWh per year of RPS-eligible deliveries offering high portfolio value through new long-term contracts. In addition, based on deliveries from current projects, PG&E does not expect the need for deliveries from new projects until 2020 and beyond.

**3. Discuss how the Project is consistent with the utility's Procurement Plan and meets utility procurement and portfolio needs (e.g. capacity, electrical energy, resource adequacy, or any other product resulting from the project).**

The proposed PPAs are consistent with PG&E's goal to procure 1,000 GWh per year in the 2012 RPS Solicitation. In addition, the Projects' 2020 Initial Energy Delivery Dates will satisfy PG&E's renewable energy portfolio needs, which are projected in 2020 and beyond. Furthermore, because the PPAs are long-term, and deliveries from the Projects are expected to satisfy the criteria of Portfolio Content Category One, any deliveries in excess of PG&E's portfolio need will be bankable and available for use to satisfy future compliance period needs.

**4. Describe the preferred project characteristics set forth in the solicitation, including the required deliverability characteristics, online dates, locational preferences, etc. and how the Project meets those requirements.**

The Projects are also consistent with PG&E's preferred project characteristics set forth in the 2012 RPS Solicitation. PG&E's 2012 RPS Solicitation Protocol expressed a preference for bundled in-state resources delivering energy and capacity at a delivery point assigned by the CAISO inside PG&E's service territory. The Projects are consistent with these preferences. The Projects will interconnect to the CAISO and PG&E is entitled to all of the Projects' Contract Capacity, including Capacity Attributes, from the Projects to enable PG&E to meet its Resource Adequacy or successor program requirements, as the CPUC, CAISO or other regional entity may prescribe.

The PPAs conform to PG&E's Commission-approved 2012 RPS Plan by delivering an average of 53 GWh per year to fill a portion of PG&E's RPS net short position. The transactions comply with RPS program requirements, meet the portfolio needs outlined by the 2012 RPS Plan, and meet the project characteristics set forth in the solicitation. Finally, the PPAs are competitive when compared to the other bids submitted in PG&E's 2012 RPS Solicitation and final shortlisted offers.

**5. Sales**

a) **For Sales contracts, provide a quantitative analysis that evaluates selling the proposed contracted amount vs. banking the RECs towards future RPS compliance requirements (or any reasonable other options).**

b) **Explain the process used to determine price reasonableness, with maximum benefit to ratepayers.**

This section is not applicable because the agreements are for the purchase, not sale, of energy.

**6. Portfolio Optimization Strategy**

a) **Describe how the proposed procurement (or sale) optimizes IOU's RPS portfolio (or entire energy portfolio). Specifically, a response should include:**

i. **Identification of IOU's portfolio optimization strategy objectives that the proposed procurement (or sale) are consistent with.**

ii. **Identification of metrics within portfolio optimization methodology or model (e.g. PPA costs, energy value, capacity value, interest costs, carrying costs, transaction costs, etc.) that are increased/decreased as a result of the proposed transaction.**

iii. **Identification of risks (e.g. non-compliance with RPS requirements, regulatory risk, over-procurement of non-bankable RPS-eligible products, safety, etc.) and constraints included in optimization strategy that may be decreased or increased due to proposed procurement (or sale).**

The PPAs are consistent with PG&E's objectives of achieving and maintaining RPS compliance and minimizing customer costs over time. The PPAs help to meet the objective of filling the net short RPS compliance position through the steady and moderate procurement of cost effective RPS-eligible products through long-term contracts with start dates towards the latter part of the current decade. In order to minimize the total cost impact of the RPS program to customers, Net Market Value ("NMV") and Portfolio Adjusted Value ("PAV") calculations were used to evaluate the transactions' cost for PG&E's customers relative to the forecast market benefits provided by each offer. These transactions reduce the risk of non-compliance with RPS requirements by reducing the net short RPS compliance position beginning in 2020, consistent with PG&E's portfolio needs.

Although the Projects are not scheduled to deliver to PG&E until 2020, they are expected to reach commercial operation before the end of 2016 in order to leverage the small wind

Investment Tax Credit ("ITC"), which reduces the risk of project non-viability and further helps to minimize customer costs.

**b) Description of how proposed procurement (or sale) is consistent with IOUs overall planned activities and range of transactions planned to optimize portfolio.**

As stated in the 2012 RPS Plan, PG&E plans to fill the net short RPS compliance position through the steady and moderate procurement of cost effective RPS-eligible products through long-term contracts with start dates towards the latter part of the current decade. These PPAs, with Initial Energy Delivery Dates in 2020, are consistent with this approach.

**B. Bilateral contracting – if applicable**

**1. Discuss compliance with D.06-10-019 and D.09-06-050.**

**2. Specify the procurement and/or portfolio needs necessitating the utility to procure bilaterally as opposed to a solicitation.**

**3. Describe why the Project did not participate in the solicitation and why the benefits of the Project cannot be procured through a subsequent solicitation.**

This section is not applicable because the PPAs resulted from PG&E's 2012 RPS Solicitation and not from bilateral negotiations.

**C. Least-Cost, Best-Fit (LCBF) Methodology and Evaluation**

**1. Briefly describe IOU's LCBF Methodology and how the Project compared relative to other offers available to the IOU at the time of evaluation.**

PG&E filed its 2012 RPS Shortlist Report on June 7, 2013 in Advice Letter 4238-E, a Supplement to the 2012 RPS Shortlist Report on July 10, 2013 in Advice Letter 4238-E-A, and a second Supplement to the 2012 RPS Shortlist Report on July 15, 2013 in Advice Letter 4238-E-B. On December 19, 2013, the CPUC approved Resolution E-4631, approving PG&E's Advice Letter 4238-E, as supplemented by Advice 4238-E-A and Advice 4238-E-B.

The RPS statute requires PG&E to procure the "least-cost best-fit" ("LCBF") eligible renewable resources.[3] The LCBF decision directs the utilities to use certain criteria in their bid ranking[4] and 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. PG&E's approved process for identifying the LCBF renewable resources focuses on four primary areas:

a. Market Valuation;
b. Portfolio Fit;
c. Project Viability; and

3 Pub. Util. Code § 399.14(a)(2)(B).

4 D.04-07-029.

d. RPS Goals.

PG&E examined the reasonableness of the PPAs using the LCBF evaluation criteria from the 2012 RPS Solicitation. The general finding is that the PPAs ranked favorably compared to the other projects received in PG&E's 2012 RPS Solicitation. A more detailed discussion of PG&E's evaluation of the PPAs is provided in Confidential Appendix A.

**a. 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 is based on an evaluation of the contract price in the PPA.

The transmission adder adjusts offer prices to include the cost, if any, of bringing the power from the generating facility to PG&E's network. Each bid is associated with a transmission cluster based upon the location of the facility. The costs in the CAISO interconnection study are used for bid evaluation.

PG&E's analysis of the market value and transmission adder is confidential and addressed in Confidential Appendix A.

**b. Portfolio Fit**

Portfolio fit considers how well an offer's features match PG&E's portfolio needs. PG&E evaluated the offer's consistency with portfolio fit as described in the 2012 RPS Plan and Protocol and filed its initial 2012 RPS Shortlist Report on June 7, 2013.

The PAV intends to more accurately reflect the value of renewable resources to PG&E customers. Specifically, the PAV methodology starts with Net Market Value results, which reflect the value of a transaction relative to market forward curves, as an initial quantitative valuation. Additional quantitative adjustments are then made for aspects of market valuation, transmission adder, and portfolio fit described herein and for other factors that impact the value of a transaction with respect to PG&E's portfolio. Using PG&E's PAV methodology for the 2012 RPS Solicitation, the Projects compared favorably to the other 2012 RPS shortlisted offers. Additional information about the PAV methodology is provided in Confidential Appendix A and Advice Letter 4238-E-B.

**c. Project Viability**

Project viability is based on three categories: 1) Company / Development Team, 2) Technology, and 3) Development Milestones. It is assessed by the CPUC developed Project Viability Calculator ("PVC"). The PVC is a tool for IOUs to evaluate the viability of a renewable energy project, relative to all other projects that bid into the California utilities' RPS solicitations. The PVC uses standardized categories and criteria to quantify a project's strengths and weaknesses in key areas of renewable project development.

PG&E's analysis of Project Viability and PVC score are confidential and can be found in Confidential Appendix A.

### d. RPS Goals

PG&E assesses the offer's consistency with and contribution to California's goals for the RPS program and the offer's support of PG&E's supplier diversity goals (collectively "RPS Goals"). The RPS Goals assessment considers non-quantitative factors, legislative findings, and declarations that increase California's reliance on renewable energy, consistency with the CPUC's Water Action Plan, Executive Order S-06-06 which established a goal the state would meet twenty percent of its renewable energy needs with electricity produced from biomass, and supplier diversity.

### 2. Indicate when the IOU's Shortlist Report was approved by Energy Division.

The 2012 Shortlist Report was approved by Resolution E-4631 on December 19, 2013.

## D. Compliance with Standard Terms and Conditions (STCs)

### 1. Does the proposed contract comply with D.08-04-009, D.08-08-028, and D.10-03-021, as modified by D.11-01-025?

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 and D.07-02-011, as modified by D.07-05-057 and D.07-11-025. These terms and conditions were compiled and published in D.08-04-009. Additionally, the non-modifiable term related to Green Attributes was finalized in D.08-08-028 and the non-modifiable terms related to RECs were finalized in D.10-03-021, as modified by D.11-01-025. The non-modifiable standard terms and conditions in the PPAs conform exactly to the "non-modifiable" terms set forth in Attachment A of D.08-04-009, as modified by D.08-08-028 and by Appendix C of D.10-03-021, as modified by D.11-01-025.

### 2. Using the tabular format, provide the specific page and section number where the RPS non-modifiable STCs are located in the contract.

The locations of non-modifiable terms in both of the PPAs are indicated in the table below; the locations are identical in both PPAs, so only one table is provided:

| Non-Modifiable Term in the two PPAs for the Altamont and Dyer Road Projects | Contract Section Number | Contract Page Number |
|---|---|---|
| STC 1: CPUC Approval | 1.44 | 4 – 5 |
| STC 2: Green Attributes and RECs | | |
| • Definition of Green Attributes | 1.119 | 12 |
| • Conveyance of Green Attributes | 3.2 | 32 |
| STC 6: Eligibility | 10.2(b) | 58 |
| STC 17: Applicable Law | 10.12 | 65 |

| **Non-Modifiable Term in the two PPAs for the Altamont and Dyer Road Projects** | **Contract Section Number** | **Contract Page Number** |
|---|---|---|
| STC REC 1: Transfer of RECs | 10.2(b) | 58 |
| STC REC 2: WREGIS Tracking of RECs | 3.1(k)(viii) | 29 |

**3. Provide a redline of the contract against the utility's Commission-approved pro forma RPS contract as Confidential Appendix E to the filed advice letter. Highlight modifiable terms in one color and non-modifiable terms in another.**

A redline comparison of each PPA with PG&E's 2012 Pro Forma PPA is provided in Confidential Appendices E1 and E2.

### E. Portfolio Content Category Claim and Upfront Showing (D.11-12-052, Ordering Paragraph 9)

**1. Describe the contract's claimed portfolio content category.**

As described in Section I.E and in further detail below, the PPAs satisfy the upfront showing required for Portfolio Content Category One.

**2. Explain how the procurement pursuant to the contract is consistent with the criteria of the claimed portfolio content category as adopted in D.11-12-052.**

SB 2 1X, which is codified at Public Utilities Code Section 399.11, and following, established three portfolio content categories that apply to RPS-eligible generation associated with RPS procurement contracts signed after June 1, 2010. D.11-12-052 requires that IOUs make an upfront showing related to the categorization of each proposed RPS procurement transaction. Specifically, for approval of contracts meeting the criteria of Portfolio Content Category One, an IOU may show the RPS-eligible generator has its first point of interconnection with the WECC transmission system within the boundaries of a California balancing authority area.

The Projects meet the upfront showing required for Portfolio Content Category One because they are in-state RPS-eligible renewable resources that expect to have their first point of interconnection with the WECC transmission system within the CAISO, a California balancing authority. Therefore, the RPS-eligible procurement from the Projects satisfies the criteria for Portfolio Content Category One adopted in D.11-12-052.

**3. Describe the risks that the procurement will not be classified in the claimed portfolio content category.**

There is no known risk that the electric power would not be categorized as Portfolio Content Category One.

**4. Describe the value of the contract to ratepayers if:**

**1. Contract is classified as claimed**

**2. Contract is not classified as claimed**

The value of the PPAs, as described and assessed in this Advice Letter, is based on the assumption that the procurement meets the criteria of Portfolio Content Category One. If the PPAs are not classified as Portfolio Content Category One, their value to PG&E and its customers could, under certain limited scenarios, be lower. For example, if PG&E (i) exceeds the applicable portfolio balance requirements set forth in Public Utilities Code Sections 399.16(c) (2); and (ii) has excess procurement in that compliance period, D.12-06-038 would require any RECs from the Projects exceeding the portfolio balance requirements to be deducted from the surplus. If the RECs from the Projects were to be classified as Portfolio Content Category Three, they would be more expensive than available REC-only purchase opportunities.

**5. Use the table below to report how the procurement pursuant to the contract, if classified as claimed, will affect the IOU's portfolio balance requirements, established in D.11-12-052.**

Per PG&E's 2012 Preliminary Annual 33 percent RPS Compliance Report, amended and filed on November 15, 2013, PG&E's current Portfolio Balance Requirements are listed in the table below.

| **Forecast of Portfolio Balance Requirements** | **Compliance Period 2 (2014-2016)** | **Compliance Period 3 (2017-2020)** |
|---|---|---|
| PCC 1 Balance Requirement<br>*CP 2 = 65% of RECs applied to procurement quantity requirement*<br>*CP 3 = 75% of RECs applied to procurement quantity requirement* | | |
| Quantity of PCC 1 RECs<br>(under contract, not including proposed contract) | 13,598 GWh | 26,374 GWh |
| Quantity of PCC 1 RECs from proposed contract | 0 | 46 GWh |
| Quantity of PCC 2 RECs | 0 | 0 |
| Quantity of PCC 2 RECs<br>(under contract, not including proposed contract) | 0 | 0 |
| Quantity of PCC 2 RECs from proposed contract | 0 | 0 |

| PCC 3 Balance Limitation<br>*CP 2 = 15% of RECs applied to procurement quantity requirement*<br>*CP 3 = 10% of RECs applied to procurement quantity requirement* | | |
|---|---|---|
| Quantity of PCC 3 RECs<br>(under contract, not including proposed contract) | 0[5] | 0[6] |
| Quantity of PCC 3 RECs from proposed contract | 0 | 0 |

**F. Long-Term Contracting Requirement**

**D.12-06-038 established a long-term contracting requirement that must be met in order for an IOU to count RPS procurement from contracts less than 10 years in length ("short-term contracts") toward RPS compliance.**

1. **Explain whether or not the proposed contract triggers the long-term contracting requirement.**
2. **If the long-term contracting requirement applies, provide a detailed calculation that shows the extent to which the utility has satisfied the long-term contracting requirement. If the requirement has not yet been satisfied for the current compliance period, explain how the utility expects to satisfy the quantity by the end of the compliance period to count the proposed contract for compliance.**

In D.12-06-038, the Commission adopted a threshold standard pursuant to SB 2 1X that requires load serving entities to sign long-term contracts in each compliance period equal to at least 0.25 percent of their expected retail sales over that same compliance period. The proposed PPAs are long-term 20-year contracts that do not trigger the minimum quantity requirement set forth in D.12-06-038.

**G. Tier 2 Short-term Contract "Fast Track" Process – if applicable**

1. **Is the facility in commercial operation? If not in commercial operation, explain the IOU's basis for its determination that commercial operation will be achieved within the required six months.**

[5] PG&E has 34.5 GWh under contract pursuant to three PCC3 REC purchase agreements that are not yet effective because they are pending CPUC approval.
[6] PG&E has 46 GWh under contract pursuant to the same three PCC3 REC purchase agreements that are not yet effective because they are pending CPUC approval.

**2. Describe and explain any contract modifications to the Commission-approved short-term pro forma contract.**

PG&E is not submitting the PPAs under the "Fast Track" process.

## H. Interim Emissions Performance Standard

**In D.07-01-039, the Commission adopted a greenhouse gas Emissions Performance Standard (EPS) which is applicable to electricity contract for baseload generation, as defined, having a delivery term of five years or more.**

**1. Explain whether or not the contract is subject to the EPS.**

A greenhouse gas Emissions Performance Standard ("EPS") was established by Senate Bill 1368 ("SB 1368"), which requires that the Commission consider emissions costs associated with new long-term (five years or greater) power contracts procured on behalf of California ratepayers.

To implement SB 1368, in D.07-01-039, the Commission adopted an 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 PPAs are not covered procurement subject to the EPS because the generating facility has a forecast annualized capacity factor of less than 60 percent and therefore is not baseload generation under paragraphs 1(a)(ii) and 3(2)(a) of the Adopted Interim EPS Rules.

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.11-05-005

**2. If the contract is subject to the EPS, discuss how the contract is in compliance with D.07-01-039.**

See Section H.1 above.

**3. If the contract is not subject to EPS, but delivery will be firmed/shaped with specified baseload generation for a term of five or more years, explain how the energy used to firm/shape meets EPS requirements.**

Not applicable.

**4. If the contract term is five or more years and will be firmed/shaped with unspecified power, provide a showing that the utility will ensure that the amount of substitute energy purchases from unspecified resources is limited such that total purchases under the contract (renewable and non-renewable) will not exceed the total expected output from the renewable energy source over the term of the contract.**

Not applicable.

**5. If substitute system energy from unspecified sources will be used, provide a showing that:**

a. **the unspecified energy is only to be used on a short-term basis; and**

b. **the unspecified energy is only used for operational or efficiency reasons; and**

c. **the unspecified energy is only used when the renewable energy source is unavailable due to a forced outage, scheduled maintenance, or other temporary unavailability for operational or efficiency reasons; or**

d. **the unspecified energy is only used to meet operating conditions required under the contract, such as provisions for number of start-ups, ramp rates, minimum number of operating hours.**

Not applicable.

## I. Procurement Review Group (PRG) Participation

### 1. List PRG participants (by organization/company).

The Procurement Review Group ("PRG") for PG&E includes the Commission's Energy Division and Office of Ratepayer Advocates, Department of Water Resources, Union of Concerned Scientists, The Utility Reform Network, the California Utility Employees, and Jan Reid, as a PG&E ratepayer.

### 2. Describe the utility's consultation with the PRG, including when information about the contract was provided to the PRG, whether the information was provided in meetings or other correspondence, and the steps of the procurement process where the PRG was consulted.

The total 20 MW offer was presented to the PRG as part of PG&E's proposed shortlist on March 27, 2013. The transaction was subsequently presented to the PRG as a potential contract for execution on November 12, 2013. It was later split into two PPAs to accommodate the Projects' interconnection configuration. Additional information is provided in Confidential Appendix A.

### 3. For short-term contracts, if the PRG was not able to be informed prior to filing, explain why the PRG could not be informed.

Not applicable.

## J. Independent Evaluator (IE)

**The use of an IE is required by D.04-12-048, D.06-05-039, 07-12-052, and D.09-06-050.**

### 1. Provide name of IE.

The Independent Evaluator ("IE") is Lewis Hashimoto from Arroyo Seco Consulting.

**2. Describe the oversight provided by the IE.**

The IE reviewed and assessed PG&E's RPS evaluation and selection process and observed the negotiations of the PPAs to ensure that they were conducted fairly.

**3. List when the IE made any findings to the Procurement Review Group regarding the applicable solicitation, the project/bid, and/or contract negotiations**.

The IE provided insights and findings to the PRG during the PRG meetings noted in Section II.I.2 above.

**4. Insert the public version of the project-specific IE Report.**

The public version of the IE report is attached to this Advice Letter as Appendix C2.

## III. Project Development Status

### A. Company / Development Team

**1. Describe the Project development team and/or company principals and describe how many years of experience they have had on the development side of the electric industry.**

Ogin has represented that the project development leadership team brings a track record of wind development and energy project experience with companies such as Ridgeline Energy, Competitive Power Ventures ("CPV"), PSEG Fossil, Third Planet Windpower, Iberdrola Renewables and others. Ogin has informed PG&E that the management team at the project development company, NDEC, which indirectly wholly owns the Projects' LLC, has in total financed 30 projects representing 3.3 GW of wind development. NDEC will also develop the 16 MW Smoke Tree project, a recently awarded RAM PPA with SCE, and the 20 MW Sand Hill Wind project, a recently awarded RAM PPA with PG&E.

**2. List any successful projects (renewable and conventional) the Project development team and/or company principals have owned, constructed, and/or operated.**

Ogin has provided the following list of projects its company principals have worked on:

| Project Name | Project Location | Technology | Generating Capacity, MW | Commercial Operation Date | Level of Project Involvement |
|---|---|---|---|---|---|
| Deer Island | Deer Island, MA | Wind | 100kW | 4/15/2011 | Development-COD |
| Rosamond Distributed Generation | Rosamond, CA | Wind | 100kW | 6/15/2011 | Development-COD |
| Hawi Wind | Big Island, HI | Wind | 10.56MW | 4/11/2006 | OEM Turbine Lead |
| Rockland Wind | American Falls,ID | Wind | 79.86MW | 12/19/2011 | Overall Project Manager for |

| | | | | | Owner from Development through Commissioning |
|---|---|---|---|---|---|
| Twin Groves I&II | McLean County, IL | Wind | 396 MW | 3/2008 | OEM Turbine Lead |
| Wildhorse I&II | Ellensberg, WA | Wind | 273 MW | 11/9/2009 | OEM Turbine Lead |
| Lake Benton II | Holland, MN | Wind | 103.5 MW | 1999 | Finance |
| Lake Benton Turbine Project I | Lake Benton, MN | Wind | 107 MW | 1998 | Finance |
| Green Power | Riverside County, CA | Wind | 16.5 MW | 1999 | Finance |
| Storm Lake II | IA | Wind | 98 MW | 1999 | Finance |
| Fenner | Madison County, NY | Wind | 30 MW | 2000 | Turbine Supply and O&M |
| Mill Run | Fayette County, PA | Wind | 15 MW | 2001 | Turbine Supply and O&M |
| Somerset | Somerset County, PA | Wind | 9 MW | 2001 | Turbine Supply and O&M |
| New Mexico Wind | Quay and DeBaca Counties, NM | Wind | 204 MW | 2003 | Turbine Supply and O&M |
| North Dakota Wind | LaMoure County, ND | Wind | 61.5 MW | 2003 | Turbine Supply and O&M |
| Oklahoma Wind | Harper and Woodward Counties, OK | Wind | 102 MW | 2003 | Turbine Supply and O&M |
| South Dakota Wind | Hyde County, SD | Wind | 40.5 MW | 2003 | Turbine Supply and O&M |
| Waymart Wind | Wayne County, PA | Wind | 64.5 MW | 2003 | Turbine Supply and O&M |
| Callahan Divide | Taylor County, TX | Wind | 114 MW | 2005 | Turbine Supply and O&M |
| Horse Hollow I | Taylor and Nolan Counties, TX | Wind | 213 MW | 2005 | Turbine Supply and O&M |
| Weatherford Wind | Custer and Washita Counties, OK | Wind | 147 MW | 2005 | Turbine Supply and O&M |
| Horse Hollow III | Taylor and Nolan Counties, TX | Wind | 223.5 MW | 2006 | Turbine Supply and O&M |

| | | | | | |
|---|---|---|---|---|---|
| Red Canyon Wind | Borden, Garza and Scurry Counties, TX | Wind | 84 MW | 2006 | Turbine Supply and O&M |
| Wilton I | Burleigh County, ND | Wind | 49.5 MW | 2006 | Turbine Supply and O&M |
| Kaheawa Wind I | Maui, HI | Wind | 30 MW | 2006 | Turbine Supply and O&M |
| Langdon I | Cavalier County, ND | Wind | 118.5 MW | 2007 | Turbine Supply and O&M |
| Oliver II Wind | Oliver County, ND | Wind | 48 MW | 2007 | Turbine Supply and O&M |
| Buffalo Gap II | Noland and Taylor Counties, TX | Wind | 233 MW | 2007 | Turbine Supply and O&M |
| Mars Hill Wind | Mars Hill, ME | Wind | 42 MW | 2007 | Turbine Supply and O&M |
| Endeavor Wind | Osceola County, IA | Wind | 100 MW | 2008 | Project Sale, Turbine Supply, and O&M |
| Endeavor Wind II | Osceola County, IA | Wind | 50 MW | 2008 | Project Sale, Turbine Supply, and O&M |
| Taconite Ridge | St. Louis County, MN | Wind | 25 MW | 2008 | Turbine Supply and O&M |
| Steel Winds | Erie County, NY | Wind | 20 MW | 2008 | Turbine Supply and O&M |
| Edom Hills | Riverside County, CA | Wind | 20 MW | 2008 | Turbine Supply and O&M |
| Silver Star 1 Wind | Eastland and Erath Counties, TX | Wind | 60 MW | 2008 | Turbine Supply and O&M |
| Crystal Lake II | Winnebago County, IA | Wind | 200 MW | 2009 | Project Sale, Turbine Supply, and O&M |
| Lee/DeKalb | Lee and DeKalb Counties, IL | Wind | 217.5 MW | 2009 | Permitting, Turbine Supply |
| Armenia Mountain | PA | Wind | 101 MW | 2009 | Project Development, Project Sale, and Turbine Supply |
| Cohocton Wind | Steuben County, NY | Wind | 125 MW | 2009 | Turbine Supply and O&M |
| Milford Wind I | Beaver and Millard | Wind | 204 MW | 2009 | Turbine Supply and O&M |

| | | | | | |
|---|---|---|---|---|---|
| | Counties, UT | | | | |
| Fowler Ridge | Benton County, IN | Wind | 100 MW | 2009 | Turbine Supply and O&M |
| Flat Ridge 1 | Barber County, KS | Wind | 50 MW | 2009 | Turbine Supply and O&M |
| Titan 1 Wind | Hand County, SD | Wind | 25 MW | 2009 | Turbine Supply and O&M |
| La Ventosa | Oaxaca, Mexico | Wind | 67.5 MW | 2009 | Turbine Supply and O&M |
| Penoles Wind | Oaxaca, Mexico | Wind | 80 MW | 2009 | Turbine Supply and O&M |
| Criterion | Oakland, MD | Wind | 70 MW | 2010 | Project Sale, Turbine Supply, and O&M |
| Kahuku Wind | Oahu, HI | Wind | 30 MW | 2011 | Turbine Supply and O&M |
| Sheffield Wind | Caledonia County, VT | Wind | 40 MW | 2011 | Turbine Supply and O&M |
| Sherbino 2 Wind | Pecos County, TX | Wind | 150 MW | 2011 | Turbine Supply and O&M |
| Eclipse Wind | Audubon and Guthrie Counties, IA | Wind | 200.1 MW | 2012 | Project Sale |
| Morning Light Wind | Adair County, IA | Wind | 101.2 MW | 2012 | Project Sale |
| Trinity Hills Wind | Archer and Young Counties, TX | Wind | 225 MW | 2012 | Turbine Supply and O&M |
| Casselman Wind Power Project | Somerset County, PA | Wind | 34.5MW | 2007 | Wind Resource to COD |
| Fenner Wind Project | Fenner, NY | Wind | 30 MW | 2001 | Wind Resource to COD |
| Hoosac Wind Project | Monroe, MA | Wind | 28.5 MW | 2013 | Wind Resource to COD |
| Madison Wind Project | Madison County, NY | Wind | 11.55 MW | 2000 | Wind Resource to COD |
| Meyersdale Wind Farm | Meyersdale,PA | Wind | 30 MW | 2003 | Wind Resource to COD |
| Blue Creek Wind Farm | Van Wert and Paulding Counties, OH | Wind | 350 MW | 2011 | Wind Resource to COD |
| Maple Ridge Wind Farm | Lewis County, NY | Wind | 321MW | 2005 | Wind Resource to COD |
| South Chestnut | Somerset County, PA | Wind | 46 MW | 2012 | Wind Resource to COD |

| | | | | | |
|---|---|---|---|---|---|
| Wind Farm | | | | | |
| Groton Wind Farm | Grafton County, NH | Wind | 48 MW | 2012 | Wind Resource to COD |
| Hardscrabble Wind Farm | Herkimer County, NY | Wind | 74 MW | 2011 | Wind Resource to COD |
| Blue Creek Wind Farm | Van Wert and Paulding Counties, OH | Wind | 350 MW | 2011 | Late Stage Development |
| New Harvest Wind Farm | Crawford County, IA | Wind | 100 MW | 2011 | Late Stage Development |
| Loraine Wind Farm | Mitchell County, TX | Wind | 150 MW | 2012 | Late Stage Development / Construction |
| Wolverine Creek Wind Farm | Bingham County, ID | Wind | 64.5 MW | 2005 | Early Stage Development |
| Hopkins Ridge Wind Farm | Columbia County, WA | Wind | 157 MW | 2005 | Early Stage Development |
| Idaho Wind Partners | Multiple Counties, ID | Wind | 183 MW | 2010 | Development |
| Combine Hills II | Umatilla County, OR | Wind | 63 MW | 2009 | Development, Construction, Operations |
| Bull Creek | Gail County, TX | Wind | 180 MW | 2008 | Development, Construction, Operations |
| Maricopa East | Kern County, CA | Solar PV | 20 MW | 2014 exp. | Development |

## B. Technology

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

#### a. Discuss the type and stage of the Project’s proposed technology (e.g. concept state, testing stage, commercially operating, utility-scale operation, ample history of operation).

Ogin designs and manufactures its own turbine, a MEWT. Ogin asserts that this turbine is a compact, robust, high-efficiency, low-cost shrouded design utilizing mature aerospace technology. This technology is still in the development stage and will be deployed commercially for one of the first times through these Projects. Ogin anticipates, based on current development plans, that the technology will be commercially operating at utility-scale in 2015. Currently, Ogin has two distributed wind projects that are in operation. Ogin installed a turbine providing power to the wastewater treatment plant located on Deer Island, Massachusetts, which has been operational since

2011, and in 2012, Ogin installed a single turbine in Kern County, California called Rosamond Energy.

Ogin cites the following advantages of its MEWT over traditional three-blade turbines:

- Higher Power Output (Capacity Factor): Delivers more energy than traditional wind turbines and enhanced production from off-axis wind/gusts
- Lower Capital Cost: Employs best practices in mass production, modular transportation, and simplified on-site assembly
- Reduced Ongoing Maintenance Costs: Eliminates many key traditional turbine failure modes with low dynamic loading and a gearless permanent magnet generator
- Safe, Environmentally-Friendly Design: Offers lower acoustic signature, improved blade shielding, and increased visibility of the shroud system to wildlife
- Lower Upfront and Overall Life Costs: Provides greater energy per unit swept area, smaller rotor, and reduced rotor loading

**b. If the technology has not been commercially demonstrated, identify whether the developer has or plans to have a demonstration project. Describe the project (MW, hours run), its results (e.g., temperature, GWh, or other appropriate metric) and its ability to perform on a commercial scale.**

The technology has been demonstrated at the distributed generation level since 2011. There are two distributed generation projects of 100 kW each in operation as described above in Section III.B.1.a. Ogin projects that the technology will be commercially operating at utility-scale in 2015.

**c. If hybrid technology will be deployed, describe the configuration and potential issues and/or benefits created by the hybrid technology.**

The technology proposed is not a hybrid technology; therefore, this section is not applicable.

**2. Quality of Renewable Resource**

**a. Explain the quality of the renewable resource that the Project will rely upon. Provide supporting documentation, such as project-specific resource studies, reports from RETI or the National Renewable Energy Lab (NREL) that supports resource quality claims and ability for the facility to provide expected generation.**

The Projects will be located in the Altamont Pass Wind Resource Area, which is a well-developed wind resource area with years of historical wind data. Furthermore, the Projects will be repowered facilities, so the developer has access to decades of historical wind data at the generation site. Ogin has informed PG&E that they have employed a third party expert to review the site's historical wind data and installed three additional meteorological towers in the area, which will provide additional capabilities for pre-construction and post-construction wind data collection.

**b. For biomass projects, please provide a fuel resource analysis and the developer's fuel supply plan. Identify:**

**i. From whom/where the fuel is being secured; and**

**ii. Where the fuel is being stored**

Not applicable.

**c. Explain whether the IOU believes that the Project will be able meet the terms of the contract given its independent understanding of the quality of the renewable resource. If necessary, reference successful nearby projects, completed studies, and/or other information.**

PG&E believes that the Projects will be able to meet the terms of the PPAs given the quality of the wind resource in the Altamont Pass Wind Resource Area, which has a large and long-standing deployment of wind turbines and the operating history of the current wind operations at the site.

**3. Other Resources Required**

**a. Identify any other fuel supply (other than the renewable fuel supply discussed above) necessary to the Project and the anticipated source of that supply;**

There is no other fuel supply necessary.

**b. Explain whether the developer has secured the necessary rights for water, fuel(s), and any other required inputs to run the Project.**

The Projects do not require water to operate beyond what is needed to wash the blades. The Projects will use water for dust control during the repowering construction. There is an existing on-site well that will supply this water, and the Projects' rights to this water are currently covered under an easement agreement.

**c. Provide the estimated annual water consumption of the facility (gallons of water/year).**

The Projects consume small quantities of water for blade washing.

**d. Explain whether the IOU believes that the Project will be able meet the terms of the contract given its independent understanding of the adequacy of the additional fuel or any other necessary resource supply. If necessary, reference successful nearby projects, completed studies, and/or other information.**

PG&E expects the Projects to meet the terms of the PPAs given the adequacy of the wind resource. There is no other fuel supply necessary.

**C. Development Milestones**

**1. Site Control**

**Explain the status of Project site control, including:**

**a. Site control type (e.g. ownership, lease, BLM Right-of-Way grant, etc.)**

**i. If lease, describe duration of site control and any exercisable extension options**

**ii. Level or percent of site control attained – if less than 100%, discuss seller's plan for obtaining full site control**

The developer has all land easements needed for the wind turbines and gen-ties for both Projects for the term of the PPAs. See Confidential Appendix A for additional information.

**2. Equipment Procurement**

**Explain the status of equipment procurement for the Project, including:**

**a. The status of the procurement of major equipment (e.g. equipment in-hand, contracts executed and equipment in delivery, negotiating contracts with supplier(s), etc.). For equipment not yet procured, explain any contingencies and overall timing.**

**b. The developer's history of ability to procure equipment.**

**c. Any identified equipment procurement issues, such as lead time, and their effect on the Project's date of operability.**

Ogin manufactures its own wind turbines and does not anticipate any issues that would impact the Projects' Initial Energy Delivery Dates. Ogin's production plan has dedicated turbines for the Projects.

**3. Permitting / Certifications Status**

**a. Describe the status of the Project's RPS-eligibility certification from the CEC. Explain if there is any uncertainty regarding the Project's eligibility.**

The Projects have been Pre-Certified by the CEC and assigned certification number 62624C.

**b. Use the following table to describe the status of all major permits or authorizations necessary for development and operation of the Project, including, without limitation, CEC authorizations, air permits, certificates of public convenience and necessity (CPCN) or permits to construct (PTC) for transmission, distribution, or substation construction/ expansion, land use permits, building permits, water use or discharge authorizations, Federal Aviation Administration authorizations, military authorizations, and Federal Communication Commission authorizations. If necessary, table may be split between public and confidential sections – permits requests with public agencies should be included in the public portion.**

| Name of Permit or Lease required | Grantor | Description of Permit or Lease | Current Status (to be filed, pending approval, approved) | Projected timeframe for approval |
|---|---|---|---|---|
| Conditional Use Permit (CUP) (Phase I) | Alameda County | CEQA review, EIR for full repowered project (Phases 1 & 2) | Initial application filed March 2013; initial DEIR hearing 12/13 | Expected at end of Q1 2014 |
| Conditional Use Permit (Phase II) | Alameda County | This permit will rely on the EIR prepared for Phase I | Application submittal by Q2 2014 | Expected Q4 2015 |
| Streambed Alteration Agreement | CDFW | Covers both Phase I and Phase II | Expected Q3 2014 | Coincides with completion of Phase I EIR |
| Clean Water Act Section 404 Nationwide Permit | USEPA | NEPA review previously completed through USACOE nationwide program | Expected Q3 2014 | Concurrent with Phase 1 CUP, but for both phases |
| State and Federal Incidental Take Authorizations | USFWS, CDFW | For tiger salamander (state and federal) and red-legged frog (federal) for Phase I | Expected Q3 2014 | Expected Q1 2014 |
| State and Federal Incidental Take Authorizations | USFWS, CDFW | For tiger salamander (state and federal) and red-legged frog (federal) for Phase II | Expected Q4 2015 | Expected Q2 2015 |
| BACI Avian Impacts Study | Alameda County, CEC | Study to support permitting process | Commenced April 2012 | Expected March 2015 |

The Projects are expected to have two phases of Conditional Use Permits. In Phase I, a multiyear avian impacts study will be conducted under a $719,000 grant from the CEC's Public Interest Energy Research ("PIER") Program. The data from this study will be used for the Phase II CUP. The objective of this three-year, Before-After, Control-Impact ("BACI") study is to measure the effect of Ogin's shrouded turbine design on avian strikes. The study is being conducted by Dr. Shawn Smallwood, which Ogin has informed PG&E is a recognized avian expert with extensive experience studying the Altamont Pass Wind Resource Area, under the supervision of the Alameda County Scientific Review Committee ("SRC"), a body that advises the County on research efforts aimed at understanding and reducing wind/avian impacts.

Ogin has advanced the hypothesis that its shrouded turbine will reduce avian strikes due to its seventy percent smaller rotor size (per unit of output) and the shroud's barrier to entry into the dangerous rotor disk area. Upon the recommendation of the SRC in May 2012, Alameda County granted Ogin a research exemption from having to remove high risk turbines in order to conduct the study at the site. To build awareness of and support for this research effort, Ogin has consulted closely and frequently with the CEC, the California Department of Fish and Wildlife ("CDFW") and the U.S. Fish and Wildlife Service ("USFWS") as well as other state officials, environmental non-governmental organizations ("NGOs") and avian experts.

The study design was developed during 2011, formally commenced in April 2012 and will result in a written report to the CEC in March 2015.

**4. Production Tax Credit (PTC) / Investment Tax Credit (ITC) / Other government funding– if applicable**

**a. Explain the Project's potential eligibility for tax credits or other government funding based on the technology of the Project and contract operation date.**

Ogin indicates that the Projects are eligible for the small wind Investment Tax Credit ("ITC"). Under current U.S. tax law, the Projects are required to reach commercial operation before the end of 2016.

**b. If the developer is pursuing PTCs/ITCs/Other, explain the criteria that must be met and the developer's plans for obtaining the PTCs/ITCs/Other.**

The main criterion to avail the ITC under current U.S. tax law is for the Projects to reach commercial operation prior to December 31, 2016. Once the Projects are in service, they will submit a tax return to the Internal Revenue Service, which will include a description of the Projects' costs eligible for the ITC. The ITC is 30 percent of the eligible Projects' costs.

**c. Explain whether the utility or the seller bears the risk if the anticipated tax credits/funding are not obtained.**

The Seller bears the risk if the ITC is not obtained.

**5. Transmission**

a. **Discuss the status of the Project's interconnection application, whether the Project is in the CAISO or any other interconnection queue, and which transmission studies are complete and/or in progress.**

The Projects plan to use existing interconnection facilities and execute a new Interconnection Agreement with the CAISO after expiration of the QF contracts. Additional information is described in Confidential Appendices A and D.

b. **Discuss the status of the Interconnection Agreement with the interconnecting utility (e.g., draft issued, executed and at FERC, fully approved).**

The Projects plan to use existing interconnection facilities and execute a new Interconnection Agreement with the CAISO after expiration of the QF contracts. Additional information is described in Confidential Appendices A and D.

c. **Describe the required network and gen-tie upgrades and the capacity to be available to the Project upon completion, including any proposed curtailment schemes.**

The Projects plan to use existing interconnection facilities. Gen-tie and network upgrades are not expected to be required. Additional information is described in Confidential Appendices A and D.

d. **Describe any required substation upgrades or construction.**

The Projects plan to use existing interconnection facilities. Substation upgrades are not expected to be required. Additional information is described in Confidential Appendices A and D.

e. **Discuss the timing and process for all transmission-related upgrades. Identify critical path items and potential contingencies in the event of delays.**

The Projects plan to use existing interconnection facilities and upgrades are not expected to be required. Additional information is described in Confidential Appendices A and D.

f. **Explain any issues relating to other generating facility projects in the transmission queue as they may affect the Project.**

Not applicable. The Projects plan to use existing interconnection facilities.

g. **If the Project is dependent on transmission that is likely to be congested at times, leading to a product that is less than 100% deliverable for at least several years, explain how the utility factored the congestion into the LCBF bid analysis.**

Expectations regarding congestion are factored into the quantitative analysis through the use of Locational Marginal Price ("LMP") multipliers.

**h. Describe any alternative transmission arrangements available and/or considered to facilitate delivery of the Project's output.**

Not applicable. The Projects plan to use existing interconnection facilities.

**D. Financing Plan**

**1. Explain developer's manner of financing (e.g. project financing, balance sheet financing, utility tax equity investment, etc.).**

Details are described in Confidential Appendix A.

**2. Describe the developer's general project financing status.**

The Projects are expected to be financed through project financing, tax equity and direct project equity. Complete financing has not been secured for the Projects, but NDEC has secured the project equity portion of funding for these Projects. Additional details are described in Confidential Appendix A.

**3. To what extent (%) has the developer received firm commitments from financers (both debt and equity), and how much financing is expected to be needed to bring the Project online?**

Details are described in Confidential Appendix A.

**4. List any government funding or awards received by the Project.**

The Projects will have two phases of CUPs. In Phase I, the Projects benefit from a $719,000 research grant to Dr. Smallwood from the CEC in support of the avian validation study for the Projects.

Additionally, the Projects expect to qualify for the federal energy ITC program by coming online prior to December 31, 2016.

**5. Explain the creditworthiness of all relevant financiers.**

Ogin has informed PG&E that the management team at NDEC, which indirectly wholly owns the Projects' LLC, has in total financed 30 projects representing 3.3 GW of wind development at previous companies.

**6. Describe developer's history of ability to procure financing.**

The management team has experience with developing and financing wind generation projects from prior positions as detailed in Section III.D.5 above.

**7. Describe any plans for obtaining subsidies, grants, or any other third party monetary awards (other than Production Tax Credits and Investment Tax Credits) and discuss how the lack of any of this funding will affect the Project.**

The Projects do not contemplate the use of any subsidies, grants or other third party monetary awards beyond what was mentioned in Section III.D.4 above.

## IV. Contingencies and/or Milestones

**Describe major performance criteria and guaranteed milestones, including those outside the control of the parties, including transmission upgrades, financing, and permitting issues.**

The PPAs include certain performance criteria and milestones that PG&E includes in its form RPS PPA contracts. These and other contingencies and milestones are addressed in Confidential Appendices A and D. The terms of the PPAs are conditioned on the occurrence of CPUC Approval, as it is defined in the PPAs.

## V. Safety Considerations

**1. What terms in the PPA address the safe operation, construction and maintenance of the Project? Are there any other conditions, including but not limited to conditions of any permits or potential permits, that the IOU is aware of that ensure such safe operation, construction and decommissioning?**

Local, state and federal agencies that have review and approval authority over the Projects are charged with enforcing safety, environmental and other regulations for the Projects, including decommissioning. Section 3.9(a) of the PPAs requires Seller to "acquire all permits and other approvals necessary for the construction, operation and maintenance of the Project." Moreover, PG&E requires that the Projects abide by contractual obligations in the PPAs that require certain Standards of Care (Section 3.5) and Covenants (Section 10.3) to not violate applicable laws, rules and regulations. These provisions serve to: (1) clarify that the burden of safe operations resides with the seller, the entity with control over on-site decisions, and (2) protect PG&E customers against bearing the cost of imprudent or unsafe operations. They do not provide PG&E with rights to enforce or dictate safe operations of the Projects as those rights reside with the governmental authorities with safety and permitting oversight over the Projects.

**2. What has the IOU done to ensure that the PPA and the Project's operation are: consistent with Public Utilities Code Section 451; do not interfere with the IOU's safe operation of its utility operations and facilities; and will not adversely affect the public health and safety?**

The Projects are owned, constructed and operated by a third party. As explained in Section V.1, the Seller is obligated to own and operate the Projects in accordance with the laws, rules, and regulations that apply to it, a number of which are referenced in the PPAs to clarify that the burden of safe operations, including operations that impact public safety, lies with the Seller. PG&E's safe operation of its utility operations and facilities is addressed in the interconnection process. While interconnection safety is not specified in the PPAs, under the terms of the PPAs, PG&E will declare that the Projects have commenced deliveries under the PPAs only after PG&E, as the transmission operator, and the CAISO have concluded such testing and given permission to commence commercial operations.

**3. If PPA or amendment is with an existing facility, please provide a matrix that identifies all safety violations found by any entity, whether government, industry-based or internal with an indication of the issue and if the resolution of that alleged violation is pending or resolved and what the progress or resolution was/is.**

Not applicable. The PPAs are for new repowered facilities, under new ownership, using a new technology.

**4. If PPA or amendment is with an existing facility, will the PPA or amendment lead to any changes in the structure or operations of the facility? Any change in the safety practices at the facility? If so, with what federal, state and local agencies did the developer confer or seek permits or permit amendments for these changes?**

Not applicable. The PPAs are for new repowered facilities, under new ownership, using a new technology.

## VI. REQUEST FOR COMMISSION APPROVAL

PG&E requests that the Commission issue a resolution no later than September 11, 2014, that:

1. Approves the PPAs in their entirety, including payments to be made by PG&E pursuant to the PPAs, subject to the Commission's review of PG&E's administration of the PPAs.
2. Finds that any procurement pursuant to the PPAs is procurement from eligible renewable energy resources for purposes of determining PG&E's compliance with any obligation that it may have to procure eligible renewable energy resources pursuant to the California RPS (Public Utilities Code Section 399.11 et seq.), D.03-06-071, D.06-10-050, D.11-12-020, D.11-12-052 or other applicable law.
3. Finds that all procurement and administrative costs, as provided by Public Utilities Code Section 399.13(g), associated with the PPAs shall be recovered in rates.
4. Adopts the following finding of fact and conclusion of law in support of CPUC Approval:
   a. The PPAs are consistent with PG&E's 2012 RPS Procurement Plan.

   b. The terms of the PPAs, 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 PPAs:

   a. The utility’s costs under the PPAs shall be recovered through PG&E’s Energy Resource Recovery Account.

   b. Any stranded cost that may arise from the PPAs is 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 findings with respect to resource compliance with the EPS adopted in R.06-04-009:

   a. The PPAs are not a form of covered procurement subject to the EPS, because the generating facilities have an expected capacity factor of less than 60 percent and, therefore, are not baseload generation under Paragraphs 1(a)(ii) and 3(2)(a) of the adopted Interim EPS Rules.

7. Adopts a finding of fact and conclusion of law that deliveries from the PPAs shall be categorized as procurement under the portfolio content category specified in Public Utilities Code Section 399.16(b)(1)(A), subject to the Commission’s after-the-fact verification that all applicable criteria have been met.

**Protests:**

Anyone wishing to protest this filing may do so by letter sent via U.S. mail, facsimile or E-mail, no later than March 12, 2014, which is 20 days after the date of this filing. Protests must be submitted to:

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

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

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

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

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

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

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

**Effective Date:**

PG&E requests that the Commission issue a resolution approving this Tier 3 advice filing by September 11, 2014.

**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.11-05-005, and R.12-03-014. 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 to the General Order 96-B service list should be directed to PGETariffs@pge.com. For changes to any other service list, please contact the Commission's Process Office at (415) 703-2021 or at Process_Office@cpuc.ca.gov. Advice letter filings can also be accessed electronically at http://www.pge.com/tariffs.

Brian Cherry /KHC

Vice President – Regulatory Relations

cc: Service List for R.11-05-005
Service List for R.12-03-014
Paul Douglas – Energy Division
Jason Simon – Energy Division

Shannon O'Rourke – Energy Division
Joseph Abhulimen – ORA
Karin Hieta – ORA
Cynthia Walker – ORA

**<u>Limited Access to Confidential Material</u>:**

The portions of this Advice Letter marked Confidential Protected Material are submitted under the confidentiality protection 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 PPAs themselves, price information, and analysis of the proposed RPS PPAs, 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.

# CALIFORNIA PUBLIC UTILITIES COMMISSION

## ADVICE LETTER FILING SUMMARY
## ENERGY UTILITY

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

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

| Utility type: | Contact Person: Kingsley Cheng |
|---|---|
| ☑ ELC ☐ GAS | Phone #: (415) 973-5265 |
| ☐ PLC ☐ HEAT ☐ WATER | E-mail: k2c0@pge.com and PGETariffs@pge.com |

| EXPLANATION OF UTILITY TYPE | (Date Filed/ Received Stamp by CPUC) |
|---|---|
| ELC = Electric GAS = Gas<br>PLC = Pipeline HEAT = Heat WATER = Water | |

Advice Letter (AL) #: **4364-E** **Tier: 3**

Subject of AL: **Power Purchase Agreements for Procurement of Eligible Renewable Energy Resources between Sand Hill Wind II, LLC and Pacific Gas and Electric Company**

Keywords (choose from CPUC listing): Agreements, Portfolio

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

If AL filed in compliance with a Commission order, indicate relevant Decision/Resolution #: N/A

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: ☑ Yes ☐ No All members of PG&E's Procurement Review Group who have signed nondisclosure agreements 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: Christen Blum, (415) 972-5443

Resolution Required? ☑Yes ☐No

Requested effective date: **September 11, 2014** 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: N/A

Service affected and changes proposed: N/A

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

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

**California Public Utilities Commission**
**Energy Division**
**EDTariffUnit**
**505 Van Ness Ave., 4th Flr.**
**San Francisco, CA 94102**
**E-mail: EDTariffUnit@cpuc.ca.gov**

**Pacific Gas and Electric Company**
**Attn: 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 CHRISTEN BLUM
SEEKING CONFIDENTIAL TREATMENT
FOR CERTAIN DATA AND INFORMATION CONTAINED IN
ADVICE LETTER 4364-E
(PACIFIC GAS AND ELECTRIC COMPANY - U 39 E)**

I, Christen Blum, declare:

1. I am presently employed by Pacific Gas and Electric Company ("PG&E"), and have been an employee at PG&E since 2011. My current title is Principal within PG&E's Energy Procurement organization. In this position, my responsibilities include negotiating PG&E's Renewables Portfolio Standard Program ("RPS") Power Purchase Agreements. 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, C1, D, E, F, and G to PG&E's Advice Letter 4364-E, submitted on February 20, 2014.

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, if applicable, and why confidential protection is justified. Finally, the matrix specifies that: (1) PG&E is complying with the limitations specified in the IOU Matrix for that type of data or information, if applicable; (2) the information is not already public; and (3) 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 explanatory text in the attached matrix.

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 February 20, 2014, at San Francisco, California.

Christen Blum

**PACIFIC GAS AND ELECTRIC COMPANY'S (U 39 E)**
**Advice Letter 4364-E**
**February 20, 2014**

## IDENTIFICATION OF CONFIDENTIAL INFORMATION

| 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 (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 |
|---|---|---|---|---|---|---|---|
| **Document: Advice Letter 4364-E** | | | | | | | |
| Appendix A | Y | Item V C) LSE Total Energy Forecast – Bundled Customer (MWh)<br><br>Item VI B) Utility Bundled Net Open (Long or Short) Position for Energy (MWh)<br><br>Item VII G) Renewable Resource Contracts under RPS program – Contracts without SEPs.<br><br>Item VII (un-numbered category following VII G)) Score sheets, analyses, evaluations of proposed RPS projects.<br><br>Item VIII A) Bid information and B) Specific quantitative analysis involved in scoring and evaluation of participating bids.<br><br>General Order 66-C. | Y | Y | Y | This Appendix contains information on PG&E's sales forecast and PG&E's renewable net open position. This information would provide market sensitive information to competitors and is therefore considered confidential.<br><br>This Appendix contains bid information and evaluations from the 2012 Solicitation; discuss, analyze and evaluate the Project and the terms of the Power Purchase Agreements ("PPAs"); contain information, analyses and evaluations of project viability; and contain confidential information of the counterparty (including financial information). Disclosure of this information would provide valuable market sensitive information to competitors. Release of this information would be damaging to negotiations.<br><br>In addition, if information about and evaluations of the project's viability is made public, it could harm the counterparties and adversely affect project viability. Finally, certain information has been obtained in confidence from the counterparty under an expectation of confidentiality. 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 V C) and VI B) the front three years of the forecast remain confidential for three years.<br><br>For information covered under Item VII G) remain confidential for three years after the commercial operation date, or one year after expiration (whichever is sooner).<br><br>For information covered under Item VII (un-numbered category following VII G), remain confidential for three years.<br><br>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. For information covered under General Order 66-C, remain confidential. |

**PACIFIC GAS AND ELECTRIC COMPANY'S (U 39 E)**
**Advice Letter 4364-E**
**February 20, 2014**

**IDENTIFICATION OF CONFIDENTIAL INFORMATION**

| 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 (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 |
|---|---|---|---|---|---|---|---|
| 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 the 2012 Solicitation. This information would provide market sensitive information to competitors and is therefore considered confidential. Furthermore, offers received outside of the 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. |

**PACIFIC GAS AND ELECTRIC COMPANY'S (U 39 E)**
**Advice Letter 4364-E**
**February 20, 2014**

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| Appendix C1 | Y | Item VII G) Renewable Resource Contracts under RPS program - Contracts without SEPs.<br><br>Item VII (un-numbered category following VII G) Score sheets, analyses, evaluations of proposed RPS projects.<br><br>Item VIII A) Bid information and B) Specific quantitative analysis involved in scoring and evaluation of participating bids.<br><br>General Order 66-C. | Y | Y | Y | This Appendix contains bid information and evaluations from the 2012 Solicitation; discusses, analyzes and evaluates the Project and the terms of the PPAs; contains information, analyses, and evaluations of project viability; and it contains confidential information of the counterparty. Disclosure of this information would provide valuable market sensitive information to competitors. Release of this information would be damaging to negotiations with other counterparties and should remain confidential. In addition, if information about and evaluations of project viability is made public, it could harm the counterparty and adversely affect project viability.<br><br>Finally, certain information has been obtained in confidence from the counterparty under an expectation of confidentiality. 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 counterparty. | For information covered under Item VII G) remain confidential for three years after the commercial operation date, or one year after expiration (whichever is sooner).<br><br>For information covered under Item VII (un-numbered category following VII G), remain confidential for three years.<br><br>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 General Order 66-C, remain confidential. |

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|---|---|---|---|---|---|---|---|
| Appendix D | Y | Item VII G) Renewable Resource Contracts under RPS program - Contracts without SEPs.<br><br>Item VII (un-numbered category following VII G) Score sheets, analyses, evaluations of proposed RPS projects.<br><br>General Order 66-C. | Y | Y | Y | This Appendix contains bid information and discusses the terms of the PPAs. Disclosure of this information would provide valuable market sensitive information to competitors. Release of this information would be damaging to negotiations with other counterparties and should remain confidential. Furthermore, the counterparty to the PPAs has an expectation that the terms of the PPAs will remain confidential.<br><br>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 counterparty. | For information covered under Item VII G) remain confidential for three years after the commercial operation date, or one year after expiration (whichever is sooner).<br><br>For information covered under Item VII (un-numbered category following VII G), remain confidential for three years.<br><br>For information covered under General Order 66-C, remain confidential. |
| Appendix E | Y | Item VII G) Renewable Resource Contracts under RPS program - Contracts without SEPs. | Y | Y | Y | This Appendix contains the PPAs for which PG&E seeks approval in the Advice Letter filing. Disclosure of certain terms of the PPAs would provide valuable market sensitive information to competitors. Release of this information would be damaging to negotiations with other counterparties and should remain confidential. Furthermore, the counterparty to the PPAs has an expectation that the terms of the PPAs will remain confidential. | For information covered under Item VII G), remain confidential for three years after the commercial operation date, or one year after expiration (whichever is sooner) |

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**Advice Letter 4364-E**
**February 20, 2014**

**IDENTIFICATION OF CONFIDENTIAL INFORMATION**

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|---|---|---|---|---|---|---|---|
| Appendix F | Y | Item VII G) Renewable Resource Contracts under RPS program - Contracts without SEPs. | Y | Y | Y | This Appendix contains the PPAs for which PG&E seeks approval in the Advice Letter filing. Disclosure of certain terms of the PPAs would provide valuable market sensitive information to competitors. Release of this information would be damaging to negotiations with other counterparties and should remain confidential. Furthermore, the counterparty to the PPAs has an expectation that the terms of the PPAs will remain confidential. | For information covered under Item VII G), remain confidential for three years after the commercial operation date, or one year after expiration (whichever is sooner). |
| Appendix G | Y | Item VII (un-numbered category following VII G) Score sheets, analyses, evaluations of proposed RPS projects.<br>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. This information should remain confidential for three years. | Remain confidential for three years. |

# Public Appendix C2

# Independent Evaluator Report

ARROYO SECO CONSULTING

# PACIFIC GAS AND ELECTRIC COMPANY 2012 RENEWABLE POWER SOLICITATION

## REPORT OF THE INDEPENDENT EVALUATOR ON CONTRACTS WITH SAND HILL WIND II, LLC: ALTAMONT PROJECT AND SAND HILL WIND II, LLC: DYER ROAD PROJECT

FEBRUARY 20, 2014

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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) undertook a competitive solicitation in 2013[1] to procure energy eligible to meet Renewables Portfolio Standard (RPS) goals. An independent evaluator (IE), Arroyo Seco Consulting (Arroyo), conducted a range of activities to review, test, and check PG&E's processes as the utility conducted outreach to renewable power developers and operators, solicited Offers, evaluated Offers, and selected a short list of Offers with which to pursue negotiations.

Subsequent to the selection of a short list, PG&E negotiated with the selected Participants to seek agreement on the terms of contracts for renewable power. On December 16, 2013, PG&E executed Power Purchase Agreements (PPAs) for renewable energy with Sand Hill Wind II, LLC: Altamont Pass and Sand Hill Wind II, LLC: Dyer Road, both currently wholly-owned subsidiaries of New Dimension Energy Company, LLC, which itself is a subsidiary of Ogin, Inc., formerly FloDesign Wind Turbine Corp., a startup manufacturer of wind turbines headquartered in Waltham, Massachusetts.

Sand Hill Wind II would comprise an existing set of wind turbines in Altamont Pass that is intended to be repowered to use turbines manufactured by Ogin that feature a new technology. The 20 MW of turbines is split into 8.6 MW interconnected to PG&E's Altamont Midway substation and 11.4 MW interconnected to PG&E's Sea West substation[2] (also known as Dyer Road substation), and because of the separate interconnections the two portions are to be metered and contracted separately.

The purpose of this report is to provide an independent review of the extent to which the project-specific negotiations with the two Sand Hill Wind project companies were fair, and an opinion about whether the contracts merit approval by the California Public Utilities Commission (CPUC).

The structure of this report follows the 2012 RPS Shortlist Report Template provided by the Energy Division of the CPUC. Topics covered include:

- The role of the IE;
- Adequacy of outreach for and robustness of the 2012 competitive solicitation;
- The fairness of the design of PG&E's least-cost, best-fit (LCBF) methodology;

[1] While the Offers were due on February 6, 2013 and were evaluated in 2013, the solicitation was issued on December 10, 2012 and is considered to be a 2012 Request for Offers.
[2] SeaWest Energy Group was a prior owner of the original turbines at the site.

- The fairness of PG&E's administration of its LCBF methodology;[3]

- Fairness of project-specific negotiations; and

- Merit of the contract for CPUC approval.

Arroyo's opinion is that the negotiations between PG&E and Ogin for the two Sand Hill Wind contracts were conducted fairly with respect to ratepayers and competitors.

Arroyo ranks the Sand Hill Wind II contracts as moderate to high in valuation and moderate in contract price. Arroyo's assessment is that the contracts' portfolio fit with PG&E's compliance needs ranks as moderate. The project viability of the contracts ranks as low compared to competing alternatives, based on Arroyo's scoring with the Energy Division's Project Viability Calculator.

Arroyo's opinion is that the Sand Hill Wind II project poses a somewhat elevated risk of contract failure due to project viability issues. In the IE's opinion, this risk level is higher than would be fully consistent with RPS agreements that merit CPUC approval. However, the IE acknowledges that policymakers may be willing to accept these heightened risks in order to pursue commercial implementation of an innovative new wind generation technology which hypothetically offers benefits for avian wildlife protection.

Arroyo disagrees with that view, particularly because a separate 20-MW block of the Sand Hill Wind site has been contracted with PG&E through its third Renewable Auction Mechanism RFO, a procurement process that does not take into account project viability in evaluation and selection, so that this technology already has an opportunity for its first-time demonstration at utility scale through that PPA.[4] Arroyo believes that the RPS solicitation process should appropriately evaluate contracts on their project viability as well as price and value, and should generally not be used to procure renewable energy from low-viability projects unless they offer other ratepayer benefits such as low price, which the Sand Hill Wind II contracts do not. Arroyo believes that PG&E's ranking of the Sand Hill Wind II PPAs as high in Portfolio-Adjusted Value (PAV) relied heavily on adjustments to valuation parameters that [redacted]

[3] The first chapter summarizes the IE report prepared in June 2013 that accompanied PG&E's short list for its 2012 RPS solicitation, covering the first four topics listed.

[4] Sand Hill Wind II's developer has also secured an RPS contract with Southern California Edison for a project through that utility's Renewable Auction Mechanism process, which should provide another venue for demonstration of the new technology.

# 1. SUMMARY OF FINDINGS FROM THE SHORT LIST REPORT

Pacific Gas and Electric Company issued a Request for Offers (RFO) on December 10, 2012, a competitive solicitation for power generation qualifying as eligible renewable energy resources (ERRs). In its solicitation protocol for the 2012 RPS RFO, PG&E announced its intent to procure about 1.25% of its retail sales volume, or about 1,000 GWh annually. This chapter summarizes the contents of the previously submitted Independent Evaluator report that described PG&E's selection of a short list for the 2012 RPS solicitation.

## A. ROLE OF THE INDEPENDENT EVALUATOR

The CPUC required an independent evaluator to participate in competitive solicitations for utility power procurement in Decision 04-12-048. It required an IE when Participants in a competitive procurement solicitation include affiliates of investor-owned utilities (IOUs), IOU-built projects, or IOU-turnkey projects. Decision 06-05-039 expanded requirements, ordering use of and IE to evaluate and report on the entire solicitation, evaluation, and selection process for the 2006 RPS RFO and future competitive solicitations. This was intended to increase the fairness and transparency of the Offer selection process.

To comply with the requirements ordered by the CPUC, PG&E retained Arroyo Seco Consulting to serve as IE for the 2012 RPS solicitation. Arroyo undertook several tasks both prior to Offer Opening and subsequently. These included reviewing PG&E's solicitation protocols and discussing the methodology with the evaluation team, observing and analyzing PG&E's outreach efforts, participating in Offer opening, reading the Offers, performing independent evaluations of Offer value and project viability, monitoring PG&E's evaluation of Offers against its evaluation criteria, and discussing the shortlisting process and decisions with PG&E's team, management, and its Procurement Review Group.

The CPUC's Decision 06-06-066 detailed guidelines for treating confidential information in IOU power procurement including competitive solicitations. It provides for confidential treatment of "Score sheets, analyses, evaluations of proposed RPS projects", vs. public treatment of the total number of projects and MW bid by resource type. Where Arroyo's reporting on the fairness of PG&E's selection of Offers requires explicit discussion of such analyses, scores, and evaluations, these are redacted in the public version of this document.

## B. ADEQUACY OF OUTREACH TO PARTICIPANTS AND ROBUSTNESS OF THE SOLICITATION

<u>Concision and clarity of solicitation materials.</u> PG&E's 2012 RPS solicitation protocol was modestly sized for a document of its type and is more concise than protocols PG&E used in prior years. Some of the bulky text specifying detailed requirements for Offers was

shifted into Attachment J from the protocol's main body. Arroyo regards this as an improvement. Arroyo believes that the contents of PG&E's 2012 RPS RFO solicitation protocol generally provided clear and comprehensible direction to Participants on how to prepare and submit complete Offer packages that could be accepted and evaluated.

By December 2012, PG&E had compiled a general contact list for use in publicizing its RFOs, totaling more than 1,900 individuals, an increase from the version of the list used in the 2011 RPS solicitation. About 60% of contacts represented entities that could develop renewable generation, sell from existing facilities, or sell RECs.

PG&E did not issue a press release to announce the issuance of the 2012 RPS RFO. News of the solicitation was picked up and reported in the electric power trade press, including Megawatt Daily. A turnout of 170 individual registrants and 167 actual attendees represented a strong response and expression of industry interest. Out of the firms represented at the 2012 bidders' conference, about three-quarters were companies directly involved with developing or owning and operating renewable energy generation.

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

Robustness of the solicitation. Arroyo's opinion is that the response to the solicitation was robust; contracting with all Offers would provide almost half of all the energy required to serve PG&E's customers. The volume of bundled energy Offers proposed, [redacted] represented a decrease by about 60% from the 2011 RPS RFO's response. The total capacity offered for in-state, bundled generation was [redacted], which is about 30% of the response in PG&E's 2011 RPS RFO.

One would expect PG&E to be easily able to meet its volume goal for the solicitation from such a robust response. [redacted]

Arroyo speculates that the lower volume of Offers this year vs. last year stems partly from the requirement for new projects to have an active interconnection application that has obtained a Phase I interconnection study. In the 2011 RPS RFO, half of all Offers were for the output of proposed projects that had not yet applied for an interconnection or obtained a completed Phase I study. Such projects would have been ineligible to participate if the 2012 requirement had been in place. Also, some developers might have chosen not to offer projects that they would rather bring on line before PG&E's preferred 2019 and 2020 dates.

Imperial Valley Offers. The CPUC has stated a public interest in obtaining a robust response to the IOUs' RPS solicitations from developers in the Imperial Valley. In the 2009 RPS solicitations it required IOUs to hold special Imperial Valley bidders' conferences.

PG&E received [redacted] Offers for output of Imperial Valley facilities, [redacted] of all proposals for bundled energy delivery. [redacted] In the 2012 solicitation the total capacity of Offers for Imperial Valley projects, [redacted], totaled about [redacted] of all capacity offered. The total annual volume of Imperial Valley projects, [redacted]. This representation of Imperial Valley projects seems to be quite robust [redacted]

Adequacy of feedback from Participants. PG&E offered an opportunity for Participants whose Offers were rejected to discuss the outcome. Arroyo observed [redacted] of these sessions [redacted] Arroyo' opinion is that PG&E sought adequate feedback from Participants about the bidding and evaluation process.

### C. FAIRNESS OF OFFER EVALUATION AND SELECTION METHODOLOGY

Arroyo's opinion is that PG&E's evaluation and selection methodology for identifying a short list for the 2012 RPS RFO was designed fairly, overall. Arroyo has some specific but narrow disagreements with the utility's approach.

Consistency with RPS Procurement Plan. PG&E's methodology was, overall, consistent with the approved 2012 RPS procurement plan. This includes numerous elements including the procurement goal, a focus on contracts that will contribute to RPS needs after 2019, equivalent treatment of existing and new projects' Offers, a preference for Offers contributing to Resource Adequacy needs, a discount to valuation for intermittent generation vs. firm energy, and use of a zero integration cost adder.

The plan also stated that PG&E would procure long-term volumes with initial delivery dates "no later than the latter part of the third compliance period." However, there was no specific element of PG&E's methodology that deterred selection of or discounted the value of Offers whose delivery starts after the end of the third compliance period. In the actual event, [redacted] and PG&E chose not to shortlist such Offers.

Market Valuation. PG&E's valuation methodology has several advantages over methods used by other utilities. It is rooted in a comparison to market forward prices rather than to model outputs for hypothetical future market price based on inputs such as forecast demand, modeled supply increases, and fuel price scenarios. It is relatively rapid to turn around several valuations, in contrast to the burdensome nature of running multiple cases of traditional utility production cost models. Net Market Value is a valuation concept that is generally accepted in the electric power industry. It provides an intuitive valuation based on the degree to which generating units are "in the money" with respect to market price.

There are some drawbacks with this approach, some of which are common to any valuation methodology for long-term PPAs. The methodology must rely on extrapolation of market forward curves rather than on direct observation of traded prices for power two decades hence. Such extrapolated prices are unlikely to be accurate forecasts. A certain degree of interpolation or projection is required to achieve hourly granularity in price assumptions. The diurnal shape of California power market pricing is changing in response to the addition of new renewable resources, and it is difficult to forecast with accuracy how hourly price profiles might evolve over three decades.

In the absence of functioning, liquid, transparent markets in California for Resource Adequacy, the valuation relied on fundamental forecasts for the value of capacity rather than on traded forward curves. These forecasts peg the value of RA at rather high and monotonically increasing levels in future years, whereas the record so far in deregulated wholesale power markets is one of boom and bust cycles.

There are challenges in estimating what Net Qualifying Capacity the CAISO will assign to a project that does not yet exist, when changes to the currently approved methodology are anticipated but not fully confirmed. PG&E's approach to estimating NQC in the 2012 RPS RFO relied on its own assumptions about what the CAISO and CPUC will adopt.

PG&E's LCBF methodology took into account both proposed price and estimated net value of each Offer, in the narrow sense that price is a key input to the utility's valuation model. However, PG&E ranked Offers by Portfolio-Adjusted Value to make a primary screening for selection purposes, and does not construct or review a separate ranking by contract price. As a result, the methodology did not systematically select the lowest-priced Offers, particularly when those projects would incur large upgrade costs.

PG&E's LCBF methodology included the costs of transmission upgrades in its value calculations of all Offers involving projects that propose to interconnect directly to the CAISO. PG&E proposed used estimates of network upgrade costs from interconnection studies including CAISO Cluster 4 Phase II studies and Cluster 5 Phase I studies.

Arroyo believes that the LCBF methodology for the 2012 RPS RFO did not appropriately count congestion charges between peripheral CAISO delivery points, such as the Palo Verde hub, and hubs internal to CAISO service territories. Arroyo recommends that PG&E develop estimates of LMP multipliers appropriate for these delivery points as it has done for zones within the main body of the CAISO grid. Arroyo's concern is that the methodology overvalues Offers for delivery at Palo Verde because it does not take into consideration the difference between the value of power delivered at the periphery of the CAISO and the value of power delivered in the core of Edison's territory; [redacted]

Transmission costs. The valuation methodology assigned estimated transmission costs to the contract price of generation in order to compare Offers fairly, taking into account the full cost of generating power including both the price paid for the PPA and the cost of upgrades required to achieve reliable deliverability for new generation. This approach provided a view of full costs of a project rather than only the energy procurement cost. This is a truer representation of the full cost to society of a new project.

The transmission cost methodology also had some drawbacks. The process of estimating transmission adders can be analytically burdensome. CAISO Phase I studies have been known to provide gross early overestimates of the actual network upgrade costs. In such a case, the methodology may disadvantage projects that have received a Phase I study but not yet a Phase II study, even though the analysis in hand is the best currently available estimate of project-specific upgrade requirements. This seems less than fully fair to some projects caught in that early stage of analysis, but is likely to be unavoidable when relying on project-specific information.

Arroyo expressed a concern in its IE report on PG&E's 2011 RPS RFO that PG&E applied transmission adders to projects that interconnect to the CAISO but did not include any estimate of network upgrade costs for projects that interconnect to the Imperial Irrigation District's grid. Arroyo believes that excluding network upgrade costs when valuing Offers located in California within IID's territory could unfairly bias selection towards IID-interconnecting projects. In those cases California ratepayers would end up bearing the upgrade costs in their rate base, but they happen to be businesses and households whose transmission rate base is outside the CAISO grid, so these costs were not taken into account when PG&E estimated the value of the contract offer.[5]

In its Decision approving PG&E's 2012 RPS procurement plan, the CPUC stated that "the Commission agrees with PG&E that no preferences should be given to CAISO-interconnected projects or to projects otherwise interconnected." By loading the valuation of CAISO-interconnected projects with network upgrade costs but not considering them when valuing IID-interconnected projects, the methodology created a potentially systematic preference for the latter. In Arroyo's opinion, PG&E's calculation of net value is not a neutral metric for comparing CAISO- and non-CAISO-interconnected projects. This resulted in a selection bias which is the opposite of the concern previously expressed by stakeholders including IID, fearing discrimination against IID-interconnected projects.

Not only did PG&E's method for calculating transmission adders omit network upgrades on the IID grid that are caused by new projects, it also omitted the cost of network upgrades that could or would be required in the CAISO grid for new generation built in

[5] Developers have objected that they paid, up front, the full cost of the required network upgrades. However, IID's practice is to provide the project with transmission service credits equivalent to that payment; the credits can be used to reduce the operating cost of transmitting the project's output to an IID-CAISO intertie point (though the project earns no interest for upfront financing the upgrades). To the extent that these credits reduce the project's expenses and reduce IID's transmission revenues, IID's customers make up the loss of revenues through rates. On that basis Arroyo's opinion is that IID ratepayers end up bearing some or all of the cost of network upgrades, and that these grid costs should be counted in evaluating whether a project should be built or not.

IID's territory. Specifically, SDG&E estimated the impact of new "external" generation built to interconnect onto IID's grid upon SDG&E's network reliability. At some level of new build within IID's territory, SDG&E would have to construct new 69-kV transmission lines in its territory in order to accommodate flows from those projects into its Imperial Valley substation and westward into its territory without overloads. Because projects that interconnect to IID's grid did not obtain an analysis of such reliability network upgrades to SDG&E's grid in their interconnection studies, PG&E was unable to obtain project-specific information about how to estimate CAISO upgrade costs driven by such effects.

Project viability. The implementation of the Project Viability Calculator as a screening tool in the evaluation of Offers brought several advantages. The Calculator is a step in the direction of more standardized evaluation of viability across all three IOUs. It provides a broader set of criteria by which projects are assessed than was the case with PG&E's prior approach to scoring viability. The range of scores from zero to 100 gives more visibility to differences between projects than prior methods that use single-digit scores.

There are still opportunities to improve the use of the Calculator. It is a somewhat crude screening tool with noise in the scoring process; differences of only two or three points between projects should not be regarded as determinative in selecting one and rejecting the other, because the difference falls within the error of the analysis. Some Participants chose to self-score their proposals in grossly inflated ways that overstate the Offer's viability beyond any reasonable measure. Arroyo believes this renders the self-scored Calculators submitted with offer packages too unreliable to use without review and correction.

PG&E's protocol stated that the utility "will evaluate the project viability of each offer" using the Project Viability Calculator, and that "PG&E will review all submissions and adjust self-scores as appropriate." Similarly, PG&E's presentation in its Participants' Webinar indicated that "All offers will be scored" using the Calculator.

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

Arroyo's opinion is that PG&E's process for evaluating and selecting Offers for its 2012 RPS RFO short list was, overall, conducted in a fair and generally consistent manner. Arroyo disagreed with some of PG&E's choices.

FARINESS OF REJECTION OF OFFERS FOR NON-CONFORMANCE

After Offers were received, PG&E performed a detailed review of the packages in order to identify deficiencies that needed to be addressed and to assess which Offers deviated from the requirements of the solicitation protocol.

Some Participants submitted Offers for full-capacity PPAs, but the interconnection applications and studies showed that their projects had applied for energy-only interconnections. PG&E communicated the need for correct classification of interconnections and gave Participants an opportunity to reprice their Offers.

[redacted] were rejected by PG&E for nonconformance with the RFO's requirements; this is a relatively small number compared to rejections in PG&E's prior RPS solicitations. Most did not meet the requirement that new projects must have at least a CAISO Phase I interconnection study or its equivalent. [redacted] projects that proposed to interconnect to non-CAISO balancing authority areas outside California did not have means of delivering their energy to a CAISO intertie point as Category 2 resources nor a proposal to arrange to be managed using a pseudo-tie or dynamic transfer agreement. In each case Arroyo agreed with PG&E's judgment that these proposals did not meet the RFO's requirements.

Short-term Offers. PG&E accepted [redacted] Offers that proposed delivery terms of five years, despite the statement in the public solicitation protocol that "PG&E is seeking offers with a term of at least 10 years. Short-term offers will not be considered." These [redacted] were Offers to extend existing contracts for delivery of power [redacted] PG&E's motivation for imposing the minimum 10-year delivery term was to ensure that the RPS-eligible energy would qualify as Category 1 deliveries and be "bankable" for purposes of counting towards PG&E's future compliance needs. However, if [redacted] proposals were to qualify as extensions of existing contracts rather than as new contracts, PG&E [redacted] believed that the energy sold during the contract extension would receive grandfathered treatment and be available to use to meet later RPS compliance needs. On that basis PG&E chose to accept [redacted] Offers.

[redacted]

Overall, Arroyo's opinion is that PG&E's decisions to reject Offers for failure to meet the stated requirements of the solicitation protocol were fair both to Participants submitting non-conforming proposals and those submitting conforming Offers.

REASONABLENESS OF PARAMETERS AND INPUTS

Nearly all parameters and inputs that PG&E used in its evaluation of the 2012 RPS RFO Offers were reasonably and fairly chosen, in Arroyo's opinion. Arroyo identified only one issue regarding the choices PG&E made about parameters and inputs that merits discussion.

PG&E chose inputs to its valuation of the buyer curtailment option using its business judgment about the size of the CAISO imbalance charges, ancillary services costs, and similar costs that would be avoided by exercising the option. The inputs are based on assumptions requiring subjective judgment. PG&E later assumed that the curtailment option would be more valuable for projects in NP-15 than elsewhere, which would imply that the adjustment to NMV for these benefits should be higher for NP-15 projects.

TRANSMISSION COST ADDERS AND INTEGRATION COSTS

PG&E closely followed its public and nonpublic protocols in administering its procedures for transmission adders. The team relied on data from interconnection studies or interconnection agreements to estimate the cost of network upgrades for new projects.

As stated in the discussion of PG&E's LCBF methodology, there is a narrow subset of cases in which Arroyo disagrees with how PG&E applies transmission cost adders. In Arroyo's opinion, transmission cost adders should be calculated and applied when valuing projects that interconnect within California outside the CAISO's balancing authority area, using the estimates of network upgrade costs provided in those other Transmission Owners' interconnection studies. PG&E ignored network upgrade costs that are borne by ratepayers of other balancing authority areas and that do not affect rates of PG&E customers.

PG&E's protocols did not specifically address how to calculate transmission adders for new projects with non-CAISO delivery points, and did not explicitly call for excluding these transmission costs. However, the non-public protocol for market valuation specified that transmission network upgrade costs would be subtracted in calculating Net Market Value. In future RFOs it would be better for the procurement plan and solicitation protocol to state explicitly that transmission adders will be set to zero for non-CAISO-interconnecting projects so that this element of the methodology is transparent to regulators and developers.

Arroyo would have applied transmission adders to projects that will interconnect to IID's grid, using IID facility studies as the basis for network upgrade cost adders. [redacted]

With the exception of projects outside the CAISO, Arroyo's opinion is that PG&E properly assessed and applied transmission adders to Offers. PG&E applied no integration cost adder, consistent with the Decision approving the 2012 RPS procurement plans.

USE OF ADDITIONAL CRITERIA IN CREATING A SHORT LIST

PG&E's overall approach to creating a short list was to rank PPA Offers for delivery of bundled energy by Portfolio-Adjusted Value and to select highest-valued Offers. Short list selection was also strongly influenced by PG&E applying its seller concentration criterion, and placing an extra emphasis on the buyer curtailment option value component of PAV.

Seller concentration. In an initial pass, the highest-ranked Offers were selected for the short list (regardless of technology) [redacted] The seller concentration criterion was applied to screen out Offers that would lead to shortlisting a total [redacted] from any individual developer or development consortium.

The implementation of the seller concentration criterion had some uneven effects. [redacted][6]

[redacted]

Resource diversity and buyer curtailment option as other criteria. After the initial selection of the highest-PAV Offers (as constrained by avoiding excess seller concentration), PG&E selected lower-valued Offers outside of strict economic ranking, in two categories.

[redacted]

[redacted]

[redacted][7] [redacted]

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6 [redacted]

7 [redacted]

*(Footnote continued)*

[redacted]

By selecting these [redacted] out of strict value rank order based on other evaluation criteria, PG&E increased the size of its initial short list [redacted]

Project viability. Overall, PG&E followed the methodology stated in its RFO protocol:

> "PG&E will evaluate the project viability of each offer using the June 2, 2011 CPUC adopted version of the PVC. Participants are requested to self-score each of their offers using the PVC…PG&E will review all submissions and adjust self-scores as appropriate."

The PG&E team used the Project Viability Calculator to score the projects considered for selection as well as some others; [redacted]. PG&E did not score every single Offer variant for project viability, and left the self-scores intact for lower-valued Offers that were rejected based on lower value.

RPS Goals and environmental risks. Appendix K to PG&E's 2012 solicitation protocol stated three specific subcomponents of the RPS Goals evaluation criterion. These included adherence to legislative direction, consistency with the CPUC's Water Action Plan, and support for Executive Order S-06-06 regarding biomass-fueled generation.

In the 2012 RFO, PG&E initially reviewed and scored [redacted] for consistency with RPS goals and for environmental risks based on information in offer packages, focusing on projects considered for shortlisting. These Offers were deemed to be consistent with RPS goals. Two shortlisted Offers were categorized by PG&E's environmental subteam as "lacking information" based on offer packages, sufficiently incomplete that it was difficult to assess environmental risks: [redacted] PG&E did not judge the risks associated with the incompleteness of the profile of these projects as sufficient to warrant their Offers' rejection.

Delivery point. PG&E stated in its 2012 solicitation protocol a preference for projects that deliver in PG&E's service territory. The calculation of Portfolio-Adjusted Value for each Offer included adjustments that reduce the value of projects located in SP-15 or outside the CAISO. PG&E justified its selection of [redacted] out of value ranking in part because of their siting in NP-15.

Commercial operation date. The protocol clearly stated PG&E's preference to select Offers that begin delivery term in 2019-2020. With [redacted] exceptions, shortlisted Offers proposed initial delivery in 2019 or 2020. The exceptions are projects currently contracted with PG&E that proposed to commence deliveries for new PPAS on the termination of the current PPAs, including [redacted]

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[redacted]

Supplier diversity. An element of the RPS Goals evaluation criterion is whether an Offer will contribute towards PG&E's supplier diversity goals. Among developers submitting to the 2012 RPS RFO, none were CPUC-certified WMDVBEs. This compares unfavorably to prior years in which PG&E received Offers from diverse business enterprises.

ANALYSIS OF PG&E'S SHORT LIST SELECTION

Arroyo disagreed with one aspect of how PG&E applied its methodology and with a few of the choices made in the selection process.

- Imperial Irrigation District Transmission Adders. In Arroyo's opinion it would have been fairer to apply transmission adders for upgrade costs in IID's grid, even though those costs are not directly borne by PG&E ratepayers. In Arroyo's opinion, the methodology advantages projects within IID's territory whose net valuations are uncompetitive when full costs, including required grid upgrades, are taken into account. This disparate treatment seems less than fully fair. [redacted] It seems undesirable from a public policy standpoint to select projects that are not the least-cost alternatives when all costs to society, including costs to IID customers residing in California, are considered.

- Offer Ranked Low for Project Viability. Arroyo ranked [redacted] in the bottom quartile among all Offers for project viability. Arroyo would not have selected such a project for the short list [redacted]

[redacted]

- [redacted] creates an appearance that PG&E has violated the principle of technology-neutral evaluation and selection that the regulator has suggested in its IE template.

- Screening for Seller Concentration. In Arroyo's opinion, it would have been preferable if PG&E had set the MW cutoff for any developer or consortium to [redacted] Arroyo views the choice of [redacted] as within the latitude for PG&E to exercise its business judgment.

- Maximum Buyer Curtailment. PG&E chose to select [redacted] in NP-15 that offered the maximum hours of buyer curtailment. Arroyo is uncertain whether PG&E's belief that NP-15 project curtailments offer the most benefit to its ratepayers is accurate, or whether ZP-26 projects might provide comparable benefits.

Although Arroyo disagreed with these particular choices that PG&E made, the basis for most of these disagreements centers on differences in business judgments about relative priorities, not on choices made contrary to the solicitation protocol. Arroyo believes that PG&E's selections, based on its subjective business judgment, are reasonable.

Overall fairness of administration. Despite a handful of disagreements, Arroyo Seco Consulting's overall judgment is that PG&E's decisions to select or reject Offers to arrive at a short list for the 2012 RPS RFO were reasonable and justifiable, overall. Most disagreements between Arroyo and PG&E were about choices Arroyo would have not made if it were administering the RFO, but that Arroyo agrees are choices a reasonable person could make if she had different priorities or emphases regarding weights assigned to evaluation criteria. Arroyo believes that PG&E's choices are within the realm of "reasonable business judgment" that the CPUC allows IOUs to exercise in energy procurement.

While Arroyo believes that PG&E may be justified in omitting transmission adders for IID-interconnecting projects because those costs do not directly affect PG&E ratepayers, in Arroyo's opinion the practice is not particularly fair. Nothing in the solicitation protocols suggests that upgrade cost will not be applied for such projects; this choice lacks transparency. Arroyo's opinion is that PG&E's administration of its methodology was overall reasonable but that treatment of IID-interconnecting projects was less than fully fair.

Imperial Valley. PG&E received [redacted] for projects operating in or proposed to be sited in the Imperial Valley, 14% of the total number of conforming Category 1 Offers.

Projects sited in the Imperial Valley comprise [redacted] Overall, developers' response to propose Imperial Valley projects was robust and PG&E's selection of Imperial Valley Offers was representative of that strong response.

# 2. FAIRNESS OF PROJECT-SPECIFIC NEGOTIATIONS

This chapter provides an independent review of the extent to which PG&E's negotiations with Ogin, Inc. for two power purchase agreements for the Sand Hill Wind II project were conducted fairly with respect to competitors and to ratepayers.

Just before PG&E's steering committee made its decisions on the RFO short list in March 2013, Ogin notified PG&E that it was withdrawing its 40-MW Offer for Sand Hill Wind because a proposal to PG&E's Renewable Auction Mechanism RFO for a 20-MW portion of the project site had been selected for the RAM RFO short list. ([redacted]). In April, PG&E notified Ogin that it had selected the 20-MW variant for its short list. The parties began negotiations in early June 2013. Arroyo telephonically observed numerous negotiation sessions between PG&E and the Ogin team. Arroyo was also able to review multiple draft versions of the contract in order to identify specific proposals and counterproposals the parties made in the course of discussions. The original starting point for the negotiations was PG&E's 2012 RPS Form Agreement published with the 2012 RPS solicitation protocol in December 2012. PG&E revised and updated some subsections of its Form Agreement (changes that applied to draft PPAs with all shortlisted parties) during the course of negotiations.[8]

Arroyo's opinion is that PG&E's negotiations with the Ogin commercial team for the Sand Hill Wind II contracts were conducted in a manner that was fair to ratepayers and competitors.

## A. BACKGROUND INFORMATION

Ogin, Inc. (formerly FloDesign Wind Turbine Corp.; the company changed names in November 2013) is a start-up company founded in 2007 focused on developing, manufacturing, and commercializing a specific proprietary wind generation technology. The company proposes to manufacture a shrouded turbine design featuring a patented "mixer ejector wind turbine", much smaller in size than most conventional wind turbines whose manufacturers continue to pursue cost improvements through economies of scale. The company has been funded by venture capital and a Department of Energy grant.

[8] For example, the revised Form Agreement prevents PG&E from paying sellers for "surplus delivered energy", deliveries that exceed contract capacity in any settlement interval. It requires the seller to install equipment needed to implement buyer curtailments. The annual threshold for "excess energy", beyond which payments to the seller is reduced, was tightened to a trigger level at 115% of contract quantity from the previous trigger level of 120%. These changes and others had the general effect of enhancing ratepayer protections in the contracts resulting from the 2012 RPS RFO. Most of the changes were included in PG&E's Form Agreement for its 2013 RPS solicitation.

A hypothesis exists that this smaller, shrouded design could achieve lower levels of avian mortality than conventional turbines. The California Energy Commission has funded a research project from its Public Interest Energy Research Program to evaluate whether Ogin's shrouded design will reduce bird collision fatalities.[9] While advocates for reducing avian mortality have characterized the mixer ejector technology as "a bird safe wind turbine design" [10], to Arroyo's awareness the hypothesis has not yet been proven, though the findings from the research project should provide guidance when completed.

While Ogin has previously erected one turbine for pilot testing on Deer Island in Boston Harbor and one in the Mojave Desert west of Rosamond, this technology has not yet been deployed in a grid-connected commercial operation. Ogin's project development subsidiary, New Dimension Energy Company, executed a PPA with SCE through the fourth Renewable Auction Mechanism RFO for a 16-MW wind project named Smoke Tree near Desert Hot Springs. This contract if approved would have an on-line date of December 2015. Similarly, PG&E awarded a 20-MW contract to the Sand Hill Wind project through its third RAM RFO (by accepting this RAM contract, Ogin had to reduce the size of its proposal to the RPS RFO from 40 to 20 MW, and the project subsidiary for the RPS RFO contracts was changed to "Sand Hill Wind II, LLC" to separate it from the subsidiary contracted under the RAM contract).

A press report suggested that Ogin would deploy ten turbines at a site in Tehachapi Pass in 2013.[11] Ogin has also recently initiated the regulatory process for a wind turbine site in Garrett County, Maryland.[12] In 2012 it applied to the Bureau of Land Management for access for testing on public land at sites in Inyo and Mono Counties and in the Mojave Desert. To date Arroyo cannot confirm commercial deployment of the Ogin turbine technology, but it seems clear that the developer expects to erect turbines within the next few years.

Existing wind turbines at the Sand Hill Wind II site have been in operation under various Qualifying Facility contracts with PG&E since the 1980s; these contracts expire in 2015. Ogin intends to demolish the existing generation hardware and erect new turbines of its proprietary design, in essence repowering the old-technology generators at a site with a demonstrated wind resource.

The negotiations between PG&E and Ogin for the Sand Hill Wind II contracts continued from June through December 2013 and resulted in agreements that were executed on December 16, 2013.

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[9] California Energy Commission, "Public Interest Energy Research: 2012 Annual Report", March 2013, pages 62-65.

[10] Jim Wiegand, "Reader's Editorial: Hiding the Slaughter", East County Magazine, February 25, 2013.

[11] Fast Company, "FloDesign's Jet-Engine Turbine Will Change the Way You Think About Wind Power", September 2013.

[12] Cumberland Times-News, "Company Hopes to Build Nine Wind Turbines Near Accident", January 26, 2013.

## B. PRINCIPLES FOR EVALUATING THE FAIRNESS OF NEGOTIATIONS

Arroyo took into account several principles to evaluate the degree of fairness with which PG&E handled negotiations with Ogin to develop the Sand Hill Wind II contracts.

- Were sellers treated fairly and consistently by PG&E during negotiations? Were all sellers given equitable opportunities to advance their Offers towards final PPAs? Were individual sellers given unique opportunities to move their proposals forward or concessions to improve their contracts' commercial value, opportunities not provided to others?

- Was the distribution of risk between seller and buyer in the PPAs distributed equitably across PPAs? Did PG&E's ratepayers take on a materially disproportionate share of risks in some contracts and not others? Were individual sellers given opportunities to shift their commercial risks towards ratepayers, opportunities that were not provided to others?

- Was non-public information provided by PG&E shared fairly with all sellers? Were individual sellers uniquely given information that advantaged them in securing contracts or realizing commercial value from those contracts?

- If any individual seller was given preferential treatment by PG&E in the course of negotiations, is there evidence that other sellers were disadvantaged by that treatment? Were other proposals of comparable value to ratepayers assigned materially worse outcomes?

## C. NEGOTIATIONS BETWEEN PG&E AND SAND HILL 2

Some of the issues addressed in the negotiation included:

- <u>Contract price.</u> [redacted]

  [redacted]

[redacted]

- Buyer curtailment. When PG&E updated and revised its 2012 Form Agreement in May 2013, it removed the limit on the number of hours per contract year that the utility may invoke buyer curtailment. In other words, PG&E can choose to require a seller to shut off production for the entire contract year. [redacted]

- Failure to meet guaranteed energy production. [redacted]

[redacted]

- Project development security. [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

- Forecasting penalties. [redacted]

- Tax credits. [redacted]

Overall, Ogin requested relatively few changes from the revised version of PG&E's 2012 RPS Form Agreement provided to the seller in May 2013. Of the requested changes, PG&E granted few concessions.

Arroyo regards the changes from the Form Agreement to the Sand Hill Wind II contracts to have minimal adverse impact on ratepayers. On the issue of [redacted]

[redacted]

Arroyo did not observe PG&E providing Ogin with any non-public information that advantaged it against competing sellers. The seller's treatment by PG&E during negotiations was comparable with the treatment of its competitors in the 2012 RPS RFO. On that basis, Arroyo's opinion is that PG&E's negotiations to arrive at the two Sand Hill Wind II contracts were conducted fairly with respect to ratepayers and competitors.

# 3. MERIT FOR CPUC APPROVAL

This chapter provides an independent review of the merits of the contracts between PG&E and Sand Hill Wind II, LLC: Dyer Road Project and Sand Hill Wind II, LLC: Altamont Project against criteria identified in the Energy Division's 2012 RPS IE template.

## A. CONTRACT SUMMARY

On December 16, 2013, PG&E executed power purchase agreements for delivery of RPS-eligible energy from Sand Hill Wind II, LLC: Altamont Project and Sand Hill Wind II, LLC: Dyer Road Project.

Contract capacities for the Altamont Project and the Dyer Road Project are 8.6 MW and 11.4 MW respectively. The contract quantities for the PPAs average 23.4 and 29.5 GWh/year over the delivery term. The contracts' guaranteed commercial operation date is April 1, 2020 [redacted] The project site is located in the Altamont Pass Wind Resource Area, about eleven miles east of Livermore and eleven miles west of Tracy. Wind generators have been in use at the site for decades, on parcels of privately owned ranchland.

## B. NARRATIVE OF EVALUATION CRITERIA AND RANKING

The 2012 RPS template for IEs provided by the Energy Division calls for a narrative of the merits of the proposed project on the criteria of contract price, portfolio fit, and project viability.

<u>CONTRACT PRICE AND MARKET VALUATION</u>

Arroyo has compared the net value of the two Sand Hill Wind II contracts to relevant peer groups of previously offered competing sources of RPS-eligible energy, using the results of both PG&E's analysis and a simpler but independent model. Based on those comparisons, Arroyo opines that the valuation of the contract ranks as moderate to high compared to relevant peer groups of competing proposals, and the contract price ranks as moderate.

<u>Contract Price.</u> Deliveries to PG&E from the two Sand Hill Wind II contracts would be priced [redacted]

At this price, the two contracts fall into the second lowest-priced quartile of all Category 1 Offer variants received in PG&E's 2012 RPS RFO when ranked on levelized pre-TOD price; this is also the case when ranked on levelized price after TOD factors are applied. On that basis, Arroyo's opinion is that the two Sand Hill Wind II contracts' pricing ranks as moderate.

The Sand Hill Wind II contracts' price ranks as [redacted] among all Offers that remained in active consideration on PG&E's short list in November 2013 (that is, that had not been withdrawn by sellers or rejected previously by the utility), both before and applying adjustments for time of delivery. In other words, PG&E rejected proposed contracts that would have provided lower prices to ratepayers when deciding which PPAs to execute, making its decisions based on its LCBF valuations rather than price.

Market Valuation. When PG&E selected a short list in March 2013, it estimated PAV for all Offer variants. At that time the Sand Hill Wind Offer for a 40-MW project with a 20-year term ranked in the [redacted] among conforming Category 1 Offer variants submitted the 2012 RPS RFO. It was, however, selected for PG&E's short list out of strict PAV-rank order as described in a previous chapter; in PG&E's presentation [redacted][13] The parties subsequently renegotiated the contract price during negotiations as described in the previous chapter.

In presenting the Sand Hill Wind II contract to its Procurement Review Group in November 2013, the utility estimated the "portfolio-adjusted value" (PAV) of the contract [redacted][14] This analysis ranked the Sand Hill Wind II contract (prior to being split into two separate PPAs) as the [redacted] among the [redacted] remaining shortlisted proposals from the 2012 RPS RFO.[15]

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[13] [redacted]

[14] PG&E altered the input parameters to its PAV methodology when ranking proposed contracts for selection for execution in November 2013. [redacted], compared to the overall set of input parameters it previously used to select a short list in March 2013. While PG&E routinely updates input parameters such as market forward curve data when analyzing PAV, [redacted] At the margin, Arroyo believes that the alteration changed which PPAs were selected for execution. In particular, if PG&E had not altered its inputs, Sand Hill Wind II would have ranked [redacted] in ranking by PAV, and Arroyo speculates that PG&E would likely or should have selected higher-ranked projects [redacted]

[15] Of the Offers shortlisted in March 2013, two were withdrawn [redacted]; one was withdrawn [redacted], and one was withdrawn by [redacted]. PG&E eventually ceased further negotiations with [redacted]

Arroyo considers this ranking to have been strongly influenced by PG&E's alteration of inputs to its methodology, as described in footnote 14. Had PG&E applied the same [redacted] adders that it used in making short list decision in March 2013, Arroyo believes that the contract would have been ranked [redacted]

Arroyo performed a valuation of all Offers to the 2012 RPS solicitation using a much simpler but independent methodology with independently determined input parameters. Using that approach to estimating net market value, Arroyo ranks the executed versions of the Sand Hill Wind II contracts in the second highest-valued quartile among Offers received. The disparity between rankings using PG&E's LCBF methodology and Arroyo's independent method stems from adjustments that PG&E applies in its LCBF methodology, including the alteration to input parameters that PG&E made in November 2013, that tend to enhance the value of projects in NP-15 or ZP-26 over projects in SP-15.

Based on these comparisons, Arroyo's opinion is that the Sand Hill Wind II contracts rank as moderate to high in valuation.

PORTFOLIO FIT

Deliveries from the Sand Hill Wind II PPA are expected to begin in April 2020. The utility's 2012 RPS procurement plan expressed an expectation that it would have procured sufficient RPS-eligible energy to meet its RPS compliance needs through the third compliance period, and a strong preference for Offers with deliveries beginning in 2019 or later.[16]

In its 2012 RPS RFO, PG&E eliminated its prior use of a stand-alone metric for portfolio fit and developed an adjustment used in calculating Portfolio-Adjusted Value that measures RPS Portfolio Need [redacted] The adjustment to PAV is based on the levelized value of annual adjustments. It is in a sense an upwards adjustment to valuation for the degree to which RPS deliveries from a proposed contract provide a good fit with time periods in which the utility's portfolio is expected to have a net compliance need.

PG&E reports that the RPS Portfolio Need adjustment in the case of the Sand Hill Wind II PPAs is [redacted]

[16] In its 2013 RPS procurement plan PG&E expressed a forecasted need for incremental RPS-eligible deliveries beginning in 2020, presumably taking into account procurement from the 2012 RFO.

In contrast, the average RPS Portfolio Need adjustment for Offers received in the 2012 RPS RFO was [redacted]. The RPS Portfolio Need adjustment for the Sand Hill Wind II contracts ranks as moderate in comparison to competing Offers.

PROJECT VIABILITY

Arroyo has scored the Sand Hill Wind II project using the Energy Division's Project Viability Calculator, which lists several attributes of projects on which viability may be measured.

Project development experience. Ogin (formerly FloDesign Wind Turbine) is a start-up company founded in 2007. It has not yet brought any generation projects into commercial operation.[17] It is reported in the press that Ogin will sell turbines employing its proprietary technology to an owner of existing projects in Tehachapi Pass for deployment in commercial operation by that "first customer" in the near future[18], as opposed to Ogin itself developing a commercial wind generation project. Ogin's project development subsidiary, New Dimension Energy Company, has secured contracts with both PG&E (for a 20-MW project with Sand Hill Wind, LLC) and Edison (for a 16-MW Smoke Tree wind project in Desert Hot Springs in Riverside County) through the utilities' Renewable Auction Mechanism, and is contractually obligated to begin deliveries under those contracts by guaranteed on-line dates in 2015. Both sites have existing turbines and it is not clear to Arroyo whether old or new turbines would provide those deliveries upon the start of the RAM contracts' terms.

Sand Hill Wind's Draft Environmental Impact Report indicates the developer's intent to place 4 MW of new turbines at the site by March 2015.[19] This timing would be consistent with the statement in PG&E's filing of contracts from its third RAM solicitation that the utility expects initial deliveries on April 1, 2015.

While Ogin, Inc. has no prior experience developing and building wind generation projects for commercial operation, individual members of the company's development function have experience in independent power. The company's chief development officer was responsible for developing, financing, and constructing new generation while employed at J. Makowski, Intergen, and Public Service Enterprise Group. These companies primarily develop or developed fossil-fueled generation and to a lesser extent hydroelectric generation, not wind power (PSEG has diversified into solar power in the last four years but the executive left PSEG in 2003).

Another member of Ogin's development team was previously involved with development efforts at Competitive Power Ventures involving two wind projects in Illinois and the Colusa gas-fired plant in California. CPV sold its wind business in 2007 and the two

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17 [redacted]

18 Fast Company, loc. cit.

19 ICF International, "Sand Hill Wind Project: Draft Environmental Impact Statement", November 2013, pages 2-5.

wind projects were never built. A sales and marketing director of Ogin[20] was previously senior director of development at Ridgeline Energy, a wind developer, between 2008 and 2011, and was involved in Ridgeline's activities developing three wind facilities in Idaho which achieved commercial operation in 2010 (a joint development venture between Ridgeline and BP Wind Energy), late 2011, and late 2012.

Ownership/O&M experience. Ogin has no prior experience as a company owning or operating a commercial wind generation facility, as opposed to pilot projects. The executives mentioned above appear to have had no role in the asset management, operating, or maintenance functions (as opposed to sales and development) of wind generation in their prior employment. The technology proposed for the Sand Hill Wind II facilities is a proprietary, patented technology that differs significantly from those employed in Ridgeline Energy's facilities in Idaho [redacted] While Ogin owns the old turbines at the Sand Hill Wind sites that it purchased from AES, it was reported that AES continues to manage these turbines, not Ogin.[21]

Technical feasibility. Ogin reports that it has numerous patents on its mixer ejector wind turbine technology. Ogin's website describes the technology as "unique" and of a "breakthrough design". [redacted] As noted above, the technology has not been deployed commercially, as opposed to being pilot-tested at two sites. PG&E does not have open-book access to cost information about the turbines; Ogin has not provided an independent engineer's report verifying the cost and performance of the turbines. When the turbines enter mass production Ogin appears to anticipate purchases of conventional wind turbine components such as towers, rotors, and drivetrains; Ogin's website states that components will be "made in partnership with only top-tier suppliers". [redacted] On that basis Arroyo concludes that the Ogin turbine technology is not yet commercially proven but will use key components of commercialized technology.[22]

Resource quality. 1980's-technology wind turbines have been operating at the Sand Hill Wind II site for decades. Figures in the draft EIR show existing meteorological towers on parcels where the Sand Hill Wind II Altamont Project and Dyer Road Project turbines will be sited. [redacted]

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20 [redacted]

21 K. Shawn Smallwood, "Draft Study Design for Testing Collision Risk of FloDesign Wind Turbine in Former AES SeaWest Wind Projects in the Altamont Pass Wind Resource Area (APWRA)", April 23, 2012.

22 [redacted]

[redacted] On that basis, Arroyo speculates that the wind resource could be sufficient to support the project's production profile, but this is not specifically demonstrated by data or resource assessments provided to PG&E.

Manufacturing supply chain. Ogin will rely on its patented, proprietary mixer ejector wind turbine technology for key components of the Sand Hill Wind II turbines, with the expectation that the proprietary technology of its "unique shroud design" will improve annual energy output per kW and peak energy output per unit of swept area, as claimed on Ogin's website. The proprietary shroud design is not yet in use commercially (as opposed to in pilot testing). Project development is reliant on new manufacturing capacity: [redacted]

Site control. [redacted]. Ogin has secured full site control [redacted]

Permitting. Sand Hill Wind has applied to Alameda County for a conditional use permit for repowering at its sites in at least two phases: an initial repower to remove about seventy existing turbines and erect forty new Ogin turbines totaling 4 MW, and a subsequent phase or phases to remove the other existing turbines and install up to an additional 32 MW of Ogin turbines.[23] The County issued a draft Environmental Impact Report for the initial phase in November 2013 and held a public comment hearing in December 2013 in which some community concerns were aired about the number of turbines Ogin will erect.[24] The draft EIR identifies significant and unavoidable impacts of the project in areas such as aesthetics, biological resources, traffic, and recommends numerous mitigation measures. In the category of impact on biological resources, the draft EIR notes potential impacts to special-status species such as the California tiger salamander, California red-legged frog, vernal pool fairy shrimp, burrowing owl, golden eagle, and Swainson's hawk.

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[23] Arroyo cannot reconcile the total 36 MW of capacity cited in the Alameda County planning documents with the total of 40 MW of contract capacity in the Sand Hill Wind (RAM RFO) and Sand Hill Wind II (2012 RPS RFO).

[24] The Independent, "Officials Call for Broader, Updated Look at Safeguarding Altamont Raptors", December 27, 2013.

[redacted][25] [redacted]

Project financing status. Ogin, Inc. and its project development subsidiary New Dimension Energy Company have, to date, not financed a new commercial generation project of any technology or capacity. [redacted]

Interconnection progress. The existing turbines at the Sand Hill Wind II project site are already interconnected to the grid under the original QF agreements, under CPUC rather than FERC jurisdiction. For operation after the QF agreements expire, generators must obtain a FERC-jurisdictional interconnection through the CAISO. The CAISO has posted a technical bulletin establishing procedures for evaluating requests for repowering from owners of existing generation.[26] The CAISO allows such generator to obtain a CAISO interconnection if the total capability and electrical characteristics are "substantially unchanged"; the bulletin clarifies that a repower that results in the same or smaller MW capacity and meets reactive power requirements would not have an adverse impact on grid power flows. The bulletin identifies other changes from a repowering that would constitute "substantial change" such as an increase in short circuit duty impact or angular or voltage stability impacts.

[redacted]

Transmission requirements. [redacted]

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[25] [redacted]

[26] California ISO, "Technical Bulletin – ISO Tariff Section 25.1.2 Procedure", September 12, 2013.

[redacted]

Reasonableness of COD. [redacted]

Potential risks to meeting project deadlines include: permitting delays with Alameda County for the full repowering, a potential finding by the CAISO that the project must undergo the full interconnection study process, challenges in bringing on line a manufacturing process for hundreds of turbines, and difficulties obtaining project financing for a new and commercially unproven technology. Given these various risks and other considerations, in Arroyo's opinion it is reasonable to expect the Sand Hill Wind II project to begin deliveries to PG&E by the guaranteed commercial operation date of April 2020.

Arroyo has scored the Sand Hill Wind II contracts and the other submittals to PG&E's 2012 RPS RFO using the Energy Division's Project Viability Calculator. The independently estimated score is [redacted]; on that basis Arroyo ranks the project in the bottom quartile among Offers to the solicitation. Arroyo notes that this low ranking can be attributed to how the Calculator's design tends to discount the viability of projects with new technologies that have not previously been built and operated in commercialized settings, sponsored by companies that do not yet have a track record of financing, building, and operating projects that employ a technology which is not in commercial use.

RPS GOALS

In PG&E's 2012 RPS RFO, the utility applied an evaluation criterion for consistency with and contribution to California's goals for the RPS program. Offers were evaluated on three dimensions:

- California-based projects providing benefits to communities afflicted with poverty, high unemployment, or high emission levels;
- Impact of the project on California's water quality and use;
- Contribution to the biomass goal of Executive Order S-06-06.

Sand Hill Wind II will be located between the cities of Livermore and Tracy; both cities have median household incomes above that of the state of California as a whole, and percentages of population living in poverty below that of the state, as estimated by the U.S. Census Bureau. Tracy has an unemployment rate estimated at 12.7% for 2012 that is somewhat above that of the state as a whole. Alameda County is a non-attainment area for the 8-hour ozone standard and the PM-2.5 particulate standard. As a wind generation facility, Sand Hill Wind II will have nil to minimal impact on water quality and use. It will not contribute to the state's biomass goal. On that basis Arroyo views the project as ranking moderate on the RPS Goals criterion.

Leaving aside the definition of the RPS Goals criterion as specified for use in PG&E's 2012 RPS RFO, the Ogin turbine technology offers the possibility that repowerings using such a shrouded turbine that is smaller than the typical new conventional installation could reduce avian mortality compared to other new wind generation projects in Altamont Pass and compared to the old turbines that will be replaced. If this hypothesis were to be proven through the studies planned for the initial phase of repowering, the technology would provide an environmental benefit that could be realized at numerous older wind farm sites in California.

## C. DISCUSSION OF MERIT FOR APPROVAL

In Arroyo's opinion, the Sand Hill Wind II project poses a somewhat elevated risk of contract failure due to viability issues, a higher risk than would be fully consistent with meriting CPUC approval, and the contracts are not particularly competitive in pricing or value.

- The contract price of the two PPAs (both before and after adjustment for time-of-delivery factors) ranks moderate, not low, when compared to all Offers received in PG&E's 2012 RPS solicitation. The contract price was higher than that of any other Offers that remained on PG&E short list in November 2013 when the utility selected contracts for execution. In other words, the pricing of these contracts was near the middle of the pack of all competing proposals submitted to the solicitation, and was the least price-competitive of the shortlisted contracts that PG&E negotiated into executable form. The ranking of the PPAs against competing market alternatives is moderate, so their weak ranking against PG&E's other shortlisted Offers is not of itself a compelling reason to reject the contracts.

- PG&E's estimate of Portfolio-Adjusted Value ranked Sand Hill Wind II as high compared to all 2012 Offers; it ranked low in PAV within the short list available for execution in November 2013. Arroyo's independent analysis ranks the contract as moderate in net value when compared to all 2012 Offers. The difference in rankings stems from PG&E's adjustments applied in calculating PAV, including an input parameter that was altered in November 2013 that [redacted] Arroyo uses a net market value calculation that does not apply locational adders. [redacted].[27]

[27] The CPUC approved PG&E's 2013 RPS RFO short list report, making a finding that the short list (including the Sand Hill Wind Offer) was reasonable, in Resolution E-4631, issued on December 20, 2013.

- In Arroyo's opinion, the proposed Sand Hill Wind II facility ranks low in project viability. Ogin, Inc. does not yet have experience developing, financing, constructing, or operating and maintaining a commercial generation project. The project has not yet obtained its conditional use permit from Alameda County. Member of Ogin's development team have successful experience in developing and building fossil-fueled generation. The proprietary mixer ejector wind turbine technology for the project has been deployed at two sites for pilot testing but has not yet entered commercial use; new manufacturing capacity will be used to assemble the turbines. Arroyo speculates that the repowering project will likely not be required to undergo the CAISO's interconnection study process; it does not yet have a CAISO interconnection agreement. In Arroyo's opinion the guaranteed commercial operation date for the PPA of April 2020 is reasonable.

  Arroyo's scoring of the project's viability ranks in the bottom quartile among all Offers to PG&E's 2012 solicitation. The contract terms of the Sand Hill Wind II PPAs provide various ratepayer protections against project failure or underperformance including delay damages, termination payments, and guaranteed energy production damages, which would help mitigate the risks of low project viability.

- The PPA ranks moderate in portfolio fit when compared to all 2012 Offers when using PG&E's metric for adjusting PAV for timing of contribution to RPS compliance needs.

- Arroyo ranks the Sand Hill Wind II project as moderate on the RPS Goals evaluation criterion as defined in PG&E's 2012 RPS solicitation protocol.

Arroyo has reservations about the viability of the Sand Hill Wind II project. Arroyo believes that the project has a heightened risk of failure to achieve commercial operation compared to most Offers submitted into the solicitation and compared to lower-priced shortlisted projects that PG&E did not select for execution. While it is entirely possible and even likely that the new Ogin turbines will be manufactured and installed at the site successfully, Arroyo is concerned that there are multiple failure modes that pose heightened risks with these contracts, including risks of failure to obtain financing, of actual generation performance, and of unit cost overruns compared to the developer's assumed project economics. Arroyo is of the opinion, for example, that there is an enhanced risk compared to other proposals that the project may return to PG&E to seek contract price increases, because the Ogin turbines have not previously been manufactured in volume, and they will be assembled by the project developer and do not fully benefit from the economies of scale available to large manufacturers of wind turbines. (In such a hypothetical scenario it is not at all clear whether PG&E would agree to a requested price increase or the CPUC would approve it.)

The pricing and value of the contracts are not compelling, which could otherwise have compensated ratepayers for taking on heightened viability risks. Other shortlisted projects that PG&E has chosen not to select for execution have lower contract prices. PG&E selected the Sand Hill Wind II Offer out of strict value ranking based on its superior buyer curtailment features, but in the actual event the utility's commercial team has succeeded in moving other shortlisted Offers to parity with the curtailment features of the Sand Hill Wind II contracts through negotiations. Arroyo believes that the Sand Hill Wind II proposal would not have ranked high enough in valuation for PG&E to select for execution if the utility had not altered the inputs to its LCBF methodology in November 2013 from those employed in shortlisting decisions in March 2013.

That being said, Arroyo acknowledges that policymakers could easily find sufficient merit in the hypothesis that the Ogin turbine will result in reduced avian mortality by virtue of its design to approve the contracts regardless of viability concerns. This hypothesis has not yet been proven but will be tested in the next few years by the CEC-funded study of the first repowered turbines. Benefits for avian mortality are not an element of PG&E's RPS Goals criterion in the 2012 solicitation, but Arroyo agrees that if the hypothesis is proven true then the technology could provide environmental benefits in many settings. Arroyo's opinion, however, is that the Renewable Auction Mechanism is a better venue for procurement of renewable energy from low-viability projects than the RPS RFO, and Ogin has already succeeded in winning RAM contracts from PG&E and Edison through which the viability of the proprietary technology will be tested at ratepayers' cost and risk.

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

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Casner, Steve
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