BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	Rulemaking 10-05-006 (Filed May 6, 2010)

NOTICE OF EX PARTE COMMUNICATION BY WELLHEAD ELECTRIC COMPANY, INC.

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November 1, 2011

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OF THE STATE OF CALIFORNIA**

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WELLHEAD ELECTRIC COMPANY, INC.**

Pursuant to Rules 8.3 and 8.4 of the California Public Utilities Commission's Rules of Practice and Procedure, Wellhead Electric Company, Inc. ("Wellhead"), hereby gives notice of the following Ex Parte Communication.

On Monday, October 31, 2011, at approximately 11:00 a.m., Doug Davie, Vice President of Wellhead and Douglas K. Kerner, Attorney for Wellhead, met with Scott Murtishaw, Advisor to Commission President Michael R. Peevey and Andrew Schwartz, Energy Division, to discuss issues involving power purchase agreements entered into before the passage of AB32 and that do not have a mechanism for recovery of greenhouse gas compliance costs. The meeting was initiated by Mr. Davie and lasted approximately 45 minutes.

Attached to this Notice are the written materials presented during this meeting and include: 1) Wellhead's August 11, 2011 "15-day" Comments to the California Air Resources Board's ("CARB") July 25, 2011 Revisions to the Cap-and-Trade Regulation; 2) CARB's Resolution 11-32, dated October 20, 2011 adopting the Cap-and-Trade Program; 3) California Public Utilities Commission Resolution E-4027, dated December 14, 2006; and 4) Summary of Issues on Greenhouse Gas Costs and Pre-AB 32 Contracts.

Copies of this Notice may be obtained by contacting Deric J. Wittenborn at (916) 447-2166 or djw@eslawfirm.com.

November 1, 2011

Respectfully submitted,

By: /s/

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COPY

August 11, 2011

Clerk of the Board
California Air Resources Board
1001 I Street
Sacramento, California 95814

Subject: Comments of Wellhead Electric Company, Inc. on July 25, 2011 Revisions to the Cap-and-trade Regulation

Dear Clerk and Board Members:

Wellhead Electric Company, Inc. ("Wellhead") offers the following comments on the California Air Resources Board ("CARB") July 25, 2011 Notice of Availability of Modified Text for the Proposed California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms Regulation, Including Compliance Offset Protocols ("cap-and-trade").

Wellhead remains very concerned that the proposed cap-and-trade regulations are unfair to, and create problems for, power sales contracts entered into before AB32 was signed into law when such contracts do not have any mechanism available for recovery of GHG costs (hereinafter "Pre-AB32 Contracts"). The failure to address this matter creates multiple problems, and not just for the generator.

Foremost, without addressing this issue, the allocation of allowances to utilities is fundamentally flawed because it gives allowances based on costs that will not be incurred by the utility. Second, not only will the generator be without any ability to recover its costs, but behaviors in contradiction of the state's GHG emission reduction goals are rewarded because the buyer will be economically benefit by running the facility more because it does not incur the GHG costs. Hence, CARB's policy intentions for GHG costs to be directly considered in the economic dispatch of generating resources and for ratepayers to see the carbon price signal of generation purchased by a utility will be undermined.

The need for appropriate treatment of Pre-AB32 contracts has been noted by the CARB, CPUC, CEC, and in other settings dating back to the early work of the Market Advisory Committee. The CPUC and the CEC noted in their opinion on GHG strategies in R. 06-04-009 that Pre-AB 32 Contracts should be addressed: "independent power producers may have contracts with utilities that extend beyond 2012 for which there is no clear provision for recovery of new GHG costs." The Initial Statement of Reasons notes the need for specialized treatment at Footnote 22.

It is therefore disappointing that the proposed regulations do not address the issue, based apparently on the hope by CARB, as indicated in the staff summary, that Pre-AB32 Contracts will be renegotiated. While bilateral negotiations could possibly solve the problems in some instances, relying on renegotiation does not make good public policy as a primary strategy, particularly without clear guidance and a backstop alternative, as we propose below. Under the proposed regulation, Pre-AB32 Contracts will be the only fossil fueled power purchase options for which the distribution utility does not incur carbon costs, and in the case of tolling agreements where a utility can call on or effectively run the generator without incurring such cost the utility will have an incentive not to renegotiate the Pre-AB32 Contract. Moreover, the result of this built-in utility incentive to run such a generator more than would be the case if it did confront appropriate carbon costs will be increased GHG production, is contrary to AB32's primary policy objective.

Thus, relying on parties to renegotiate contracts is unlikely to resolve the Pre-AB32 Contract concern in addition to being cumbersome and expensive from a transactional perspective. Even if CARB had authority to mandate renegotiation, which we doubt, such an approach would still require CARB to revisit its decision allocating allowances to the electric utilities and/or use allowances allocated to its set-aside at some future date if renegotiations are unsuccessful. CARB should act decisively to avoid the uncertainty, controversy and delay that will result by failing to address the issue at the outset.

Most importantly, not addressing the issue is clearly inconsistent with the allocation of free allowances to distribution utilities. In the allocation methodology, CARB explicitly notes that there will be a cost burden resulting from GHG compliance costs associated with fossil generation being passed from suppliers (whether purchased under contract or produced from utility owned generation) to utility customers. Allowances CARB provides to a distribution utility are intended to result in full compensation for GHG compliance costs that are expected to be passed through to consumers. The determination of how many free allowances a utility receives assumes all of its fossil based generation has a GHG cost. Pre-AB32 Contracts were included in the utilities' S-2 Filings, which are the basis for estimating the utilities' costs associated with the cap-and-trade program. However, Pre-AB32 Contracts will be a source of fossil fueled power for which the utility does not incur GHG compliance costs under the proposed regulations. Hence, unless the regulations require the utility to provide Pre-AB32 Contract suppliers with allowances associated with the power they take under the pre-AB32 Contracts (which would be the most logical, best and simplest solution), the regulations will freely allocate allowances to distribution utilities for GHG costs that will not be incurred by them.

The assumptions in the methodology for allocating allowances to utilities are clear that: 1) GHG costs will be incurred by fossil generators; 2) utility customers should see/incur such GHG costs; and 3) allocations are intended to cover these costs the utility pays to the generator. Yet, as currently written, only the first will occur. This is clearly an inconsistency/error that must be fixed.

Wellhead believes there is a very simple solution within the construct of the proposed regulations that is fully consistent with the proposed regulations and is consistent with the policy objective of making the cost of GHG emissions transparent. The solution 1) takes account of the fact that the free allocation methodology assumes all of the fossil generation in a utility's portfolio will have a GHG cost that is being passed through to its customers and 2) builds on the inclusion of a "beneficial holding relationship" in the proposed regulation. Further, the proposal encourages discussions that could lead to renegotiations before the program starts, improves the incentives for a successful outcome by providing clear guidance as to what CARB expects, and accounts in advance for the chance those discussions are not fruitful.

Accordingly and to that end, Wellhead recommends adding a new subparagraph (4) to section 95834(a) of the proposed regulations reading as follows"

> "(4) In the event there is a long-term contract for the sale of electricity at wholesale to a distribution utility which:
>
> i) does not directly or indirectly provide or refer to GHG costs either explicitly or through a CPUC authorized pricing basis that includes GHG costs;
>
> ii) was fully executed before the final approval of AB32 (September 27, 2006); and
>
> iii) has not been renegotiated and approved by the appropriate regulatory authority as of January 1, 2012 to address GHG costs,
>
> then, a beneficial holding relationship is deemed to exist pursuant to section 95834(a)(1)(A) without further action. The electric distribution utility party to that long-term contract shall purchase and hold allowances for the eventual transfer to the other party to the long-term contract for the sole purpose of supplying that other party with compliance instruments to cover emissions resulting from deliveries under the long term power supply contract.

This addition to the regulations provides clear direction on a backstop approach to addressing the Pres AB32 Contract problem while also eliminating the inconsistency/error in the proposed regulations free allowance allocation methodology. The result will support the clear objectives of AB32 to reduce GHG emissions with regulations/programs that make the full cost of GHG emissions transparent to consumers.

There is a second relatively minor issue that Wellhead understands is already understood by CARB. That is the "beneficial holding relationship" provisions should be available to all long term contracts, not just those executed at an earlier time. This is a useful mechanism and there are recently negotiated/executed contracts that would benefit from its administrative simplicity. The change to the regulations to fix this issue is to simply remove the date limitation in the definition of Long-Term Contract.

Wellhead would be pleased to address any questions CARB has on these matters.

Sincerely,

Douglas E. Davie
Vice President
Wellhead Electric Company, Inc.

cc: Douglas K. Kerner, Esq., Ellison, Schneider & Harris.

State of California
AIR RESOURCES BOARD

California Cap-and-Trade Program

Resolution 11-32

October 20, 2011

Agenda Item No.: 11-8-1

WHEREAS, sections 39600 and 39601 of the Health and Safety Code authorize the Air Resources Board (ARB or Board) to adopt standards, rules, and regulations and to do such acts as may be necessary for the proper execution of the powers and duties granted to and imposed upon the Board by law;

WHEREAS, the California Global Warming Solutions Act of 2006 (AB 32; Chapter 488, Statutes of 2006; Health and Safety Code section 38500 et seq.) declares that global warming poses a serious threat to the economic well-being, public health, natural resources, and environment of California and creates a comprehensive multi-year program to reduce California's greenhouse gas (GHG) emissions to 1990 levels by 2020;

WHEREAS, AB 32 added section 38501 to the Health and Safety Code, which expresses the Legislature's intent that ARB coordinate with State agencies and consult with the environmental justice community, industry sectors, business groups, academic institutions, environmental organizations, and other stakeholders in implementing AB 32; and design emissions reduction measures to meet the statewide emissions limits for greenhouse gases in a manner that minimizes costs and maximizes benefits for California's economy, maximizes additional environmental and economic co-benefits for California, and complements the State's efforts to improve air quality;

WHEREAS, section 38501(c) of the Health and Safety Code declares that California has long been a national and international leader on energy conservation and environmental stewardship efforts, and the program established pursuant to AB 32 will continue this tradition of environmental leadership by placing California at the forefront of national and international efforts to reduce GHG emissions;

WHEREAS, section 38501(d) of the Health and Safety Code confirms that national and international actions are necessary to fully address the issue of global warming, but action taken by California to reduce GHG emissions will have far reaching effects by encouraging other states, the federal government, and other countries to act;

WHEREAS, section 38510 of the Health and Safety Code designates ARB as the State agency charged with monitoring and regulating sources of GHG emissions in order to reduce these emissions;

WHEREAS, section 38560 of the Health and Safety Code directs ARB to adopt rules and regulations in an open public process to achieve the maximum technologically feasible and cost-effective GHG emissions reductions from sources or categories of sources;

WHEREAS, section 38562 of the Health and Safety Code requires ARB to adopt GHG emissions limits and emissions reduction measures by regulation to achieve the maximum technologically feasible and cost-effective reductions in GHG emissions in furtherance of achieving the statewide GHG emissions limit, to become operative beginning on January 1, 2012;

WHEREAS, section 38562 of the Health and Safety Code requires ARB, to the extent feasible and in furtherance of achieving the statewide GHG emissions limit, to do all of the following:

> Design the regulations, including distribution of emissions allowances where appropriate, in a manner that is equitable, seeks to minimize costs and maximize total benefits to California, and encourages early action to reduce GHG emissions;
>
> Ensure that activities undertaken to comply with the regulations do not disproportionately impact low-income communities;
>
> Ensure that entities that have voluntarily reduced their GHG emissions prior to the implementation of this section receive appropriate credit for early voluntary reductions;
>
> Ensure that activities undertaken pursuant to the regulations complement, and do not interfere with, efforts to achieve and maintain federal and state ambient air quality standards and to reduce toxic air contaminant emissions;
>
> Consider cost-effectiveness of these regulations;
>
> Consider overall societal benefits, including reductions in other air pollutants, diversification of energy sources, and other benefits to the economy, environment, and public health;
>
> Minimize the administrative burden of implementing and complying with these regulations;
>
> Minimize leakage; and

Consider the significance of the contribution of each source or category of sources to statewide emissions of greenhouse gases.

WHEREAS, sections 38562(c) and 38570 of the Health and Safety Code authorize ARB to adopt regulations that utilize market-based compliance mechanisms;

WHEREAS, section 38570 of the Health and Safety Code also directs ARB, to the extent feasible and in furtherance of achieving the statewide GHG emissions limit, to do all of the following before including any market-based compliance mechanism in the regulations:

Consider the potential for direct, indirect, and cumulative emissions impacts from these mechanisms, including localized impacts in communities that are already adversely impacted by air pollution;

Design any market-based compliance mechanism to prevent any increase in the emissions of toxic air contaminants or criteria air pollutants; and

Maximize additional environmental and economic benefits for California, as appropriate.

WHEREAS, section 38570(c) of the Health and Safety Code further directs ARB to adopt regulations governing how market-based compliance mechanisms may be used by regulated entities subject to GHG emissions limits and mandatory emissions reporting requirements to achieve compliance with their GHG emissions limits;

WHEREAS, section 38571 of the Health and Safety Code directs ARB to adopt methodologies for the quantification of voluntary GHG emissions reductions and regulations to verify and enforce any voluntary GHG emissions reductions that are authorized by ARB for use to comply with GHG emissions limits established by ARB; the adoption of methodologies is exempt from the rulemaking provisions of the Administrative Procedure Act;

WHEREAS, California is participating in the Western Climate Initiative (WCI), with several Canadian Partner jurisdictions considering implementing GHG cap-and-trade programs and formally linking them to form a regional market for compliance instruments;

WHEREAS, by linking California's program to WCI Partner jurisdictions, the combined programs will result in more emission reductions, generate greater potential for lower cost emissions reductions, enhance market liquidity, and will likely reduce the compliance costs of covered sources more than could be realized through a California-only program;

WHEREAS, establishing and implementing a California and regional GHG cap-and-trade program requires ARB and WCI Partner jurisdictions to harmonize a number of specific regulatory and operational provisions, including, but not limited to, sources subject to compliance obligations, cost-containment mechanisms, evaluation of regulatory baselines for existing offset protocols, procedures for developing new offset protocols, market tracking system development and operation, auction services, financial services, and market monitoring and oversight;

WHEREAS, ARB and the WCI Partner jurisdictions are working towards establishing a Regional Administrative Organization similar to other established cap-and-trade programs (e.g., Regional Greenhouse Gas Initiative) to meet the goal of regionally coordinated administration of cap-and-trade services;

WHEREAS, staff has completed a Final Regulation Order establishing a GHG cap-and-trade program for California; the regulation is set forth in Attachment A hereto and includes the following elements:

Addresses emissions of carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), sulfur hexafluoride (SF_6), and nitrogen trifluoride (NF_3);

Identifies the program scope: starting in 2012, electricity, including imports, and large (emissions >25,000 metric tons carbon dioxide per year) industrial facilities are included; starting in 2015, distributors of transportation fuels, natural gas, and other fuels are included;

Establishes a declining aggregated emissions cap on included sectors. The cap starts at 162.8 million allowances in 2013, which is equal to the emissions forecast for that year. The cap declines approximately 2 percent per year in the initial period (2013–2014). In 2015, the cap increases to 394.5 million allowances to account for the expansion in program scope to include fuel suppliers. The cap declines at approximately 3 percent per year between 2015 and 2020. The 2020 cap is set at 334.2 million allowances;

Provides for distribution of allowances through a mix of direct allocation and auction in a system designed to reward early action and investment in energy efficiency and GHG emissions reductions; allowances will be distributed for the purposes of price containment, industry transition and assistance, and fulfillment of AB 32 statutory objectives;

Establishes a market platform for allowance auction and sale;

Establishes cost-containment mechanisms and market flexibility mechanisms, including trading of allowances and offsets, allowance banking, a two year compliance period and two 3-year compliance periods, the ability to use offsets for up to 8 percent of an entity's compliance obligation, and an allowance reserve that provides allowances at fixed prices to those with compliance obligations;

Establishes a mechanism to link with other GHG trading programs and approve the use of compliance instruments issued by a linked external GHG trading program;

Establishes requirements and procedures for ARB to issue offset credits according to offset protocols adopted by the Board;

Includes four offset protocols to be considered for adoption by the Board as part of this regulatory package;

Establishes a mechanism to include international offset programs from an entire sector within a region;

Establishes a robust enforcement mechanism that will discourage gaming of the system and deter and vigorously punish fraudulent activities; and

Provides an opt-in provision for entities whose annual GHG emissions are below the threshold to voluntarily participate in this program.

WHEREAS, staff conducted over forty public workshops regarding the Final Regulation Order during the period 2008–2011, and also participated in numerous other meetings with various stakeholders to provide additional opportunities to participate in the regulatory development process;

WHEREAS, the Board has considered the community impacts of the Final Regulation Order, including environmental justice concerns;

WHEREAS, staff had prepared a document entitled “Staff Report: Initial Statement of Reasons for Proposed Regulation to Implement the California Cap-and-Trade Program” (ISOR), which presents the rationale and basis for the Final Regulation Order and identifies the data, reports, and information relied upon;

WHEREAS, public hearings and other administrative proceedings were held in accordance with the provisions of Chapter 3.5 (commencing with section 11340), part 1, division 3, title 2 of the Government Code;

WHEREAS, the Final Regulation Order was made available to the public at least 10 days prior to the public hearing to consider the Final Regulation Order;

WHEREAS, in consideration of the Final Regulation Order, written comments, and public testimony it has received to date, the Board finds that:

GHG emissions associated with entities covered by the cap-and-trade regulation account for about 85 percent of GHG emissions in the State;

Covered entities can reduce emissions to comply with the cap-and-trade regulation using a variety of currently available GHG reduction strategies, including those complementary measures identified in the Scoping Plan;

In addition to the complementary measures identified in the Scoping Plan, the cap-and-trade regulation is expected to significantly reduce GHG emissions. The cap-and-trade regulation will ensure GHG emissions levels in 2020 are equal to 1990 levels;

The cap-and-trade regulation was developed using the best available economic and scientific information and will achieve the maximum technologically feasible and cost-effective GHG emissions reductions from covered entities and offset projects;

The GHG emissions reductions resulting from the implementation of the cap-and-trade regulation are expected to be real, permanent, quantifiable, verifiable, and enforceable by ARB, and the cap-and-trade regulation complements and does not interfere with other air quality efforts;

The cap-and-trade regulation meets the statutory requirements identified in section 38562 of the Health and Safety Code;

The cap-and-trade regulation meets the statutory requirements for a market-based mechanism identified in section 38570 of the Health and Safety Code;

The cap-and-trade regulation was developed in an open public process, in consultation with affected parties, through numerous public workshops, individual meetings, and other outreach efforts;

The cap-and-trade regulation is predicated on GHG regulations that are clear, consistent, enforceable, and transparent and helps meet the goals of AB 32;

The benefits to human health, public safety, public welfare, or the environment justify the costs of the cap-and-trade regulation;

The cost-effectiveness of the cap-and-trade regulation has been considered, and the regulation will achieve cost-effective GHG emissions reductions;

The cap-and-trade regulation is consistent with ARB's environmental justice policies and will equally benefit residents of any race, culture, or income level;

Robust reporting and verification requirements associated with the cap-and-trade regulation are necessary for the health, safety, and welfare of the people of the State; and

No reasonable alternative considered, or that has otherwise been identified and brought to the attention of ARB, would be more effective at carrying out the purpose for which the regulation is proposed or would be as effective and less burdensome to affected entities than the proposed regulation.

WHEREAS, the Board further finds that:

The integrity of offsets is critical to the success of a cap-and-trade program;

It is in the interest of the State of California to pursue a comprehensive approach that aligns the incentives provided by AB 32 programs, including the cap-and-trade regulation, with statewide policy for handling solid waste, including recycling, remanufacturing of recovered materials in state, composting and anaerobic digestion, waste-to-energy facilities, landfilling, and the treatment of biomass;

Electricity rates should create the appropriate incentives for electricity conservation, greenhouse gas efficient technologies, and efficient distributed electricity generation such as combined heat and power;

Carbon pricing is an important function of the cap-and-trade regulation, and that it is equally important that if allowance value provided to electric distribution utilities for ratepayer benefit is returned directly to customers it is consistent with State efforts to promote energy efficiency and energy conservation;

Incentives created by the cap-and-trade program should motivate investment and innovation in clean technology;

The cap-and-trade regulation will establish a greenhouse gas market that allows business flexibility to comply with the regulation while also ensuring strong oversight and transparency;

State universities serve an important public service in providing affordable higher education;

Water rates should create the appropriate incentives for water conservation, greenhouse gas efficient technologies, and the efficient supply and use of water;

Carbon pricing is an important function of the cap-and-trade regulation, and that it is equally important that if allowance value is used for the benefit of water ratepayers it is used consistent with State efforts to promote efficient use and supply of water and water conservation; and

The cap-and-trade program should properly account for the emissions associated with generation and transmission of both in-State and imported electricity in accordance with AB 32.

WHEREAS, at a public hearing held December 16, 2010, the Board considered the proposed regulations for sections 95800 to 96023, title 17, California Code of Regulations (CCR). The Board considered the ISOR released on October 28, 2010, and adopted Resolution 10-42 directing several modifications proposed by staff and guidance on implementation. The Board advised staff that additional changes were necessary. As a result, on July 25, 2011, the first Notice of Public Availability of Modified Text and Availability of Additional Documents (1st 15-Day Change Notice) was issued. The public comment period for the 1st 15-Day Change Notice ended at 5:00 p.m. on August 11, 2011;

WHEREAS, additional modifications to the regulatory text were proposed in a Second Notice of Public Availability of Modified Text (2nd 15-Day Change Notice). The additional modifications addressed comments ARB staff received in the first 15-day Change Notice and were the result of additional staff analysis and stakeholder engagement. The 2nd 15-Day Change Notice was posted September 12, 2011. The public comment period for the 2nd 15-Day Change Notice ended at 5:00 p.m. on September 27, 2011;

WHEREAS, in the Final Statement of Reasons, staff is preparing responses to comments received on the record during the initial 45-day comment period, comments presented at the December 16, 2010 Board hearing both orally and in writing, comments received during the first 15-day Change Notice released July 25, 2011, and the comments received during second 15-Day Change Notice released September 12, 2011;

WHEREAS, ARB has a regulatory program certified under Public Resources Code section 21080.5, and pursuant to this program ARB conducts environmental analyses to meet the requirements of the California Environmental Quality Act (CEQA);

WHEREAS, ARB staff prepared an environmental analysis for the cap-and-trade regulation pursuant to its certified regulatory program; this analysis is contained in the Functional Equivalent Document (FED) in Appendix O to the ISOR;

WHEREAS, the FED, which sets forth a programmatic analysis of the potential environmental impacts associated with the cap-and-trade regulation and the offset protocols, including potential alternatives to the regulation, was released for public review on October 28, 2010, with a 45-day written comment period from November 1, 2010 to December 16, 2010;

WHEREAS, in Resolution 10-42, the Board also directed the Executive Officer to complete the regulatory modifications and the environmental review process in accordance with the requirements of the Administrative Procedure Act and CEQA under ARB's certified regulatory program, and to either take final action to adopt the proposed regulation or return the matter to the Board for further consideration;

WHEREAS, ARB received written comments on the potential environmental impacts of the cap-and-trade regulation during the initial 45-day public comment period, and the two subsequent 15-day comment periods associated with the two Notices of Public Availability of Modified Text;

WHEREAS, ARB staff has reviewed the written comments on the potential environmental impacts received during the comment periods and prepared written responses to these comments;

WHEREAS, on October 10, 2011, ARB released a document called the *Response to Comments on the Functional Equivalent Document Prepared for the California Cap on GHG Emissions and Market-Based Compliance Mechanisms* (Response to FED Comments) which includes a summary of written comments received on the FED that raise significant environmental issues and staff's written responses as set forth in Attachment B to this Resolution;

WHEREAS, in the FED, ARB committed to pursue an adaptive management approach to monitor and respond as appropriate to address unanticipated, adverse, localized air quality impacts and impacts from the U.S. Forest Protocol on special states, species, sensitive habitats, and federally protected wetlands as part of the implementation of the cap-and-trade regulation and the U.S. Forest Protocol;

WHEREAS, on October 10, 2011, ARB released the proposed *Adaptive Management Plan for the Cap-and-Trade Regulation* (Adaptive Management Plan) that describes ARB's commitment and process to monitor for unanticipated and unintended adverse impacts related to localized air quality resulting from implementation of the cap-and-trade regulation and adverse forestry impacts from implementation of the U.S. Forest Protocol, and ARB's commitment to developing and implementing appropriate actions to address any impacts identified as set forth in Attachment C to this Resolution;

WHEREAS, ARB has the authority under sections 39600, 39601, and 38500 et seq. of the Health and Safety Code to adopt standards, rules and regulations to address unanticipated and unintended adverse impacts related to localized air quality resulting from implementation of the cap-and-trade regulation and adverse forestry impacts from implementation of the U.S. Forest Protocol;

WHEREAS, at a duly noticed public hearing held on October 20, 2011, staff presented the Response to FED Comments and the Adaptive Management Plan for Board for approval, and the Final Regulation Order for adoption;

WHEREAS, the Board has reviewed and considered the FED, the Response to FED Comments, and the Adaptive Management Plan;

WHEREAS, CEQA and ARB's certified regulatory program require that before taking final action on any proposal for which significant environmental comments have been raised, the decision maker must approve a written response to each such comment; and

WHEREAS, CEQA and ARB's certified regulatory program require that any proposal for which significant adverse environmental impacts have been identified during the review process shall not be approved if there are feasible mitigation measures or feasible alternatives which would substantially reduce such adverse impacts.

NOW, THEREFORE, BE IT RESOLVED that the Board hereby certifies that the FED was completed in compliance with CEQA under ARB's certified regulatory program, reflects the agency's independent judgment and analysis, and was presented to the Board whose members reviewed, considered, and approved the information therein prior to acting on the proposed regulation.

BE IT FURTHER RESOLVED that the Board approves the written responses to comments raising significant environmental issues included in the Response to FED Comments.

BE IT FURTHER RESOLVED that in consideration of the FED and the Response to FED Comments, and in accordance with the requirements of CEQA and ARB's certified regulatory program, the Board adopts the Findings and Statement of Overriding Considerations as set forth in Attachment D to this Resolution.

BE IT FURTHER RESOLVED that the Board approves the *Adaptive Management Plan for the Cap-and-Trade Regulation*.

BE IT FURTHER RESOLVED that the Board adopts sections 95800 to 96023, title 17, California Code of Regulations (including the four compliance protocols incorporated by reference in the regulation: the Compliance Offset Protocols for Livestock Projects, Ozone Depleting Substances Projects, Urban Forest Projects, and U.S. Forest Projects) as set forth in Attachment A to this Resolution.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to finalize the FSOR and submit the rulemaking package to Office of Administrative Law by October 28, 2011.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to continue discussions with stakeholders to identify and propose, as necessary, during the initial implementation of the cap-and-trade program, potential amendments to the Regulation including, but not limited to the following areas:

1. Provisions to balance flexibility and accumulation of market power including auction frequency, and holding and purchase limits or other methods;

2. Definition of Resource Shuffling to: (a) provide appropriate incentives for accelerated divestiture of high-emitting resources by recognizing that these divestitures can further the goals of AB 32; and (b) ensure changes in reported emissions from imported electricity that serves California do not result merely in a shift of emissions within the Western Electricity Coordinating Council region, but reduces overall emissions;

3. Allocation of allowances for emissions associated with natural gas combustion emissions as written in section 95852 of the cap-and-trade regulation; and

4. Distribution of allowance value associated with cap-and-trade compliance costs from using electricity to supply water, and the expected ability of allowance allocation and other measures to adequately address the incidence of these costs equitably across regions of the State.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to continue to review information concerning the emissions intensity, trade exposure, and in-State competition of industries in California, and to recommend to the Board changes to the leakage risk determinations and allowance allocation approach, if needed, prior to the initial allocation of allowances for the first or second compliance period, as appropriate, for industries identified in Table 8-1 of the cap-and-trade regulation, including refineries and glass manufacturers.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to continue to work with stakeholders to further develop the allowance allocation approach for the petroleum refining sector and associated activities in the second and third compliance periods. This evaluation should include additional analysis of the Carbon Weighted Tonne approach and treatment of hydrogen production, coke calcining, and other activities that may operate under a variety of ownership structures.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to initiate a study to analyze the ability of the agricultural industry, including food processors, to pass on regulatory costs to consumers, given domestic and international competition and continually fluctuating global markets. The Executive Officer shall identify and propose regulatory amendments, as appropriate.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to identify and propose new benchmarks and allowance allocation for manufacturing of new products in California, as appropriate. The allowance allocation should incorporate efforts to minimize leakage.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to monitor protocol development and to propose technical updates to adopted protocols, as needed.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to develop implementation documents laying out the process for review and consideration of new offset protocols, including a description of how staff will evaluate additionality.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to continue to work with Cal/Recycle and other stakeholders to characterize lifecycle emissions reduction opportunities for different options for handling solid waste, including recycling, remanufacturing of recovered materials in state, composting and anaerobic digestion, waste-to-energy facilities, landfilling, and the treatment of biomass. The Executive Officer shall identify and propose regulatory amendments, as appropriate, so that AB 32 implementation, including the cap-and-trade regulation, aligns with statewide waste management goals, provides equitable treatment to all sectors involved in waste handling, and considers the best available information. The Executive Officer shall report to the Board on progress in summer of 2012.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to continue to evaluate the definition of position holders relative to railroads and other specific types of fueling operations, work with interested stakeholders, and propose modifications to the regulations as appropriate to become effective prior to the start of the second compliance period.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to coordinate with stakeholders to develop a mechanism to achieve GHG emission reductions from the national security/military sector (NAICS 92811) beginning January 1, 2014.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to coordinate with the State universities and stakeholders to evaluate options for compliance, with amendments to the regulation as appropriate, including options on the use of auction revenue and report back to the Board in summer of 2012.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to monitor progress on bilateral negotiations between counterparties with existing contracts that do not have a mechanism for recovery of carbon costs associated with cap-and-trade for industries receiving free allowances pursuant to Section 95891, and identify and propose a possible solution, if necessary. For fixed-price contracts between independent generators and Investor Owned Utilities, the Board further directs the Executive Officer to work with the California Public Utilities Commission (CPUC) to encourage resolution between contract counterparties.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to work with the CPUC and Publicly Owned Utilities to reflect the findings of the Board that the impact of the cap-and-trade regulation on electricity rates creates appropriate incentives to further the goals of AB 32.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to work with the CPUC and the Publicly Owned Utilities to reflect the finding of the Board that if allowance value provided to the electric distribution utilities for ratepayer benefit is returned directly to customers, it is consistent with State efforts to promote energy efficiency and energy conservation.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to work with the CPUC, California Energy Commission, California Independent System Operator and stakeholders to evaluate requirements for first jurisdictional deliverers of electricity and to report back to the Board in summer of 2012.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to coordinate with the Market Surveillance Committee and stakeholders to evaluate the effectiveness of the cost containment provisions of this program, including the Allowance Price Containment Reserve, offsets, banking and the three-year compliance period.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to contract with an external entity and work closely with regulated entities and other stakeholders to evaluate potential market conditions, trading dynamics, the Allowance Price Containment Reserve, and other key design features of the program prior to the beginning of the compliance obligation on January 1, 2013. The Executive Officer will make recommendations for changes, if any, necessary to address potential market design issues that are identified by or from these evaluations.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to continue to coordinate with the Commodity Futures Trading Commission and California State Attorney General's office on market oversight of the program, including the possibility of tracking forward contracts for sales of allowances.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to develop recommendations for the appropriate use of auction revenue. These recommendations should consider the Board's direction in Resolution 10-42.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to partner with the air quality management districts and air pollution control districts in the implementation of the cap-and-trade regulation, including, but not limited to, an evaluation of the impacts of the cap-and-trade program on industrial source greenhouse gas permitting and implementation of the Adaptive Management Plan. The Board further directs the Executive Officer to report back periodically to the Board on the nature and extent of this Partnership with the first report due in the first quarter of calendar year 2012.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to continue working with the WCI Partner jurisdictions to harmonize the programs by developing appropriate regulatory amendments necessary to formally link the programs, developing appropriate policy and technical protocols necessary to effectively implement the jurisdictions' programs, and working toward the establishment of a Regional Administration Organization.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer, as described in Resolution 10-42, to update the Board at least annually on the status of the cap-and-trade program. These annual updates should include elements described in Resolution 10-42, as well as the following:

The effectiveness of the cap-and-trade program;

How the cap-and-trade program is stimulating investment and innovation in clean technology;

Shifts in transportation fuel use and supply;

The status of existing offset protocols, and potential new offset protocols that could be proposed to the Board;

The status of carbon capture and sequestration technology; and

Federal greenhouse gas activities, including federal equivalency for a State program.

I hereby certify that the above is a true and correct copy of Resolution 11-32, as adopted by the Air Resources Board.

Mary Alice Morency, Clerk of the Board

Resolution 11-32

October 20, 2010

Identification of Attachments to the Board Resolution

Attachment A: Final Regulation Order for the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms, title 17, California Code of Regulations, section 95800 to 96023, including the four Final Compliance Offset Protocols.

Attachment B: Response to FED Comments as found at: http://www.arb.ca.gov/cc/capandtrade/fed/staff-responses.pdf

Attachment C: Adaptive Management Plan as found at: http://www.arb.ca.gov/cc/capandtrade/adaptive_management/plan.pdf

Attachment D: Findings and Statement of Overriding Considerations, distributed at the October 20, 2011 Board hearing.

PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

ENERGY DIVISION — RESOLUTION E-4027
December 14, 2006

R E S O L U T I O N

Resolution E-4027. Pacific Gas and Electric Company for approval the amended and restated power purchase agreement between PG&E and Fresno Cogeneration Partners, L.P., pursuant to the Restructuring Advice Letter filing (RALF) procedure adopted in Decision (D.) 98-12-066.

By Advice Letter (AL) 2872-E filed on August 8, 2006.

SUMMARY

This resolution approves Pacific Gas and Electric Company's (PG&E) request approval of the amended and restated power purchase agreement (Amended and Restated PPA) between PG&E and Fresno Cogeneration Partners, L.P. (Fresno).

This Resolution approves the amended and restated power purchase agreement (Amended and Restated PPA) between PG&E and Fresno Cogeneration Partners, L.P. (Fresno or Fresno Cogen), as submitted by Pacific Gas and Electric Company (PG&E). The Amended and Restated PPA restructures two existing Qualifying Facility (QF) agreements totaling 33 megawatts (MW)[1] from a "must-take" delivery profile under which PG&E is required to purchase all power regardless of customer demand and market alternatives – to an economic, "as-needed" profile.

The Amended and Restated PPA is one of three agreements submitted for approval. The other two agreements are (1) a consent to assignment, which assigns the Santa Maria PPA from Santa Maria to Fresno upon which Fresno agrees to terminate it; and (2) the Santa Maria Dispatch Agreement – which

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[1] The Fresno Cogeneration Project is 25 MW and the Santa Maria Cogeneration Project is 8 MW, both have the same majority beneficial owner.

obligates Santa Maria to back up generation from the Fresno project until local transmission constraints are removed, work for which is now under way and is scheduled for completion in the second quarter of 2007.

The resolution grants the relief requested with the exception that the total requested shareholder incentive award has been reduced to 48.6% of the amount requested in AL 2872-E.

BACKGROUND

On August 8, 2006, PG&E filed AL 2872-E requesting approval of the Amended and Restated PPA between PG&E and Fresno Cogen. The Amended and Restated PPA will allow PG&E to (1) dispatch the Fresno Project when power is needed and economical, resulting in lower power procurement costs; and (2) terminate the Santa Maria Cogen, Inc. PPA.

PG&E has also requested approval of two companion agreements: the Santa Maria Dispatch Agreement and the Consent to Assignment Agreement. Together with the Amended and Restated PPA, these three agreements will accomplish the restructuring of two PPAs into one, while preserving PG&E's rights to dispatch generation capacity equal to the combined capacity for both plants and reduce capacity payments.[2]

PG&E requests that the Commission issue a resolution finding that:

(i) The Amended and Restated PPA is reasonable;

(ii) PG&E is authorized to recover all payments under the Amended and Restated PPA in PG&E's Energy Resource Recovery Account ("ERRA") including an above-market portion in the Ongoing Competition Transition Charge (Ongoing CTC), or any other cost recovery mechanism subsequently authorized by the Commission, subject only to PG&E's prudent administration of the Amended and

[2] AL 2872-E contains a detailed account of contract history for both PPAs which we opt to note, but not directly include here.

Restated PPA; and

(iii) PG&E may recover of the requested shareholder incentive amount associated with this PPA restructuring, as authorized by the Commission in D.95-12-063 as modified by D.96-01-009.

Energy Payments

Currently, the Fresno and Santa Maria projects are under a contract energy price from the PG&E/Independent Energy Producers (IEP) Settlement Agreement approved in D.06-07-032. Specifically, Fresno and Santa Maria are on the variable energy price option for natural gas-fired QFs at a fixed heat rate of 8,700 Btu/kWh and a variable O&M payment of $2/MWh. Previously, the QFs were on the five-year fixed energy priced amendments at 5.37 cents/kWh, pursuant to D.01-06-015.

Absent approval of the Amended and Restated PPA proposed in AL 2872-E, the Fresno and Santa Maria projects will continue to receive energy payments pursuant to the PG&E/IEP Settlement Agreement until September 30, 2009. After this date energy payments for these projects would be determined by the California Independent System Operator (CAISO) Day-Ahead power price. This Day-Ahead market is part of the CAISO's Market Redesign and Technology Upgrade (MRTU), currently scheduled for implementation in November 2007.

Capacity Payments

Fresno Cogen. On September 29, 1986, Fresno's predecessor-in-interest and PG&E entered into a Standard Offer 2 (SO2) PPA for the 25 MW cogeneration project. Fresno's existing SO2 PPA provides for firm capacity payments based on 25 MW for 30 years at a price of $209/kW-year. SO2 PPAs do not provide for any as-delivered capacity payments. Firm capacity payments are subject to minimum performance requirements and obligations defined in the PPA. The term of the PPA extends through March 24, 2020.

Santa Maria. On April 16, 1985, Santa Maria's predecessor in interest and PG&E entered into an Interim Standard Offer 4 PPA (ISO4) for the 8 MW Santa Maria cogeneration project. The PPA has a 30-year term for firm capacity deliveries. Under the existing PPA, firm capacity payments are based on 7 MW for 30 years at a price of $184/kW-year. Firm capacity payments are subject to minimum performance requirements and obligations defined in the PPA. The Project is also eligible for firm capacity bonus payments if its generation meets specified performance requirements. Under the existing PPA, the Santa Maria Project is paid for capacity delivered in excess of firm capacity on an as-delivered capacity basis in accordance with as-delivered capacity payment option 2.[3] On page 7, paragraph 1 of AL 2872-E, PG&E stated that the fixed, forecasted prices are set forth in Table D-2 of Appendix A of the Santa Maria PPA. However, these Appendices were inadvertently omitted from the advice letter, but provided to the Energy Division as requested.

The Commission encouraged QF contract restructuring and implementation through an expedited advice letter process

The Commission sought to encourage QF contract restructuring in its Preferred Policy Decision, D.95-12-063, as modified by D.96-01-009, by proposing an incentive mechanism to encourage the restructuring of QF contracts so that total transition costs might be reduced. Specifically, shareholders would be allowed to retain 10% of the net ratepayer benefits resulting from a renegotiation:

> "We endorse an approach that involves both a monetary incentive to shareholders and conditions which foster voluntary, nondiscriminatory negotiations. We will allow shareholders to retain 10% of the net ratepayer benefits resulting from a renegotiation, which will be reflected by an adjustment to the transition cost total." (D.95-12-063, p.132)

In D.96-12-088 (the Roadmap 2 Decision), the Commission stated its interest in "establishing a generic and possibly expedited process by which we can assess

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[3] Under ISO4 Capacity Payment Option 2, the QF will receive fixed, forecasted as-available capacity prices, which are not levelized, for up to 10 years, after which as-available capacity payments will revert to either (1) the posted as-delivered capacity price (a.k.a., the shortage cost) in the 10th year, or (2) the contractually-specified 10th year fixed capacity price, whichever is higher. To illustrate, if the posted price in the 10th year was $200/kW-year and the contractually-specified 10th year fixed capacity price was $175/kW-year, the QF would be paid $200/kW-year for as-available capacity in years 11 to 30.

the reasonableness of contract restructuring in a manner which respects the principles outlined in our Preferred Policy Decision" (D.96-12-088, p.79-80).

In 1998, the Commission adopted the Restructuring Advice Letter Filing (RALF)[4] process in D.98-12-066:

> "The restructuring Advice Letter [filing] process attached as Attachment B to this decision, shall be adopted subject to the modifications and clarifications set forth in Section 7 of this decision." (D.98-12-066, Ordering Paragraph 1).

The Commission adopted the RALF process with modifications that were not included in Attachment B to D.98-12-066 but were instead set forth in the decision. A modified version of Attachment B to D.98-12-066 was attached to a previous RALF resolution, E-3898,[5] which reflects the determinations in D.98-12-066.

NOTICE

Notice of AL 2872-E was made by publication in the Commission's Daily Calendar. Pacific Gas and Electric Company states that a copy of the Advice Letter was mailed and distributed in accordance with Section III-G of General Order 96-A.

PROTESTS

There were no protests to Advice Letter 2872-E.

DISCUSSION

Energy Division has reviewed the advice letter. The Amended and Restated PPA will allow PG&E to (1) dispatch the Fresno Project when the power is needed

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4 Restructuring Advice Letter Filing ("RALF") Procedure For Review of QF Contract Restructurings.

5 E-3898, www.cpuc.ca.gov/Published/Final_resolution/41760.htm regarding PG&E AL 2537-E.

and economical for PG&E, resulting in lower power procurement costs; and (2) obligate the Santa Maria project to provide to back up generation for the Fresno project until local transmission constraints are removed (work for which is now under way and is scheduled for completion by second quarter of 2007), and (3) terminate the Santa Maria Cogen, Inc. PPA.

PG&E has complied with the RALF requirements

The restructuring advice letter shall contain the following categories of information ("a" through "h") shown below, including all relevant work papers and other relevant supporting documents, per Section 3 of the RALF procedure.[6]

a. **Identification of the QF[s], location of the QF[s'] generating facility, brief description of the generating facility size, type of technology and other pertinent or unique characteristics.**

Originally, the Fresno Cogen Project was a nominally rated 26 MW natural gas-fired combined-cycle cogeneration plant supplying process steam to its thermal host which dries agricultural products. The primary energy cycle was powered by a refurbished FT4 natural gas turbine generator set and waste heat was supplied to a Heat Recovery Steam Generator (HRSG) which in turn powers a steam turbine. However, in December of 2004, Fresno completed a repower of the facility as required by a previous contract amendment and is now nominally rated at 50 MW. The Fresno Project is located at 8105 B South Lassen Avenue, San Joaquin, California. However, under the proposed contract restructuring, only 33 MW will be under contract to PG&E.

The Santa Maria Project is an 8 MW simple cycle gas-fired power plant with one "Mars 90" gas turbine generator as the prime mover. The unfired HRSG coupled to the exhaust of the gas turbine is strictly for process steam production used to make ice. The Santa Maria Project is located at 802 South Hanson Way, Santa Maria, California.

[6] The RALF requirements are reproduced here as Attachment 1 to E-3898, a modified version of Attachment B to D.98-12-066, which reflect determinations made in D.98-12-066.

b. Ownership of the QF project[s] and related companies, including affiliate relationships of the parties involved in the transaction, if any.

The Fresno Project is owned by a limited partnership known as Fresno Cogeneration Partners, LP ("FCPLP"), a California limited partnership, with Fresno Cogen Inc. as its general partner. FCPLP acquired the Fresno project in 1994 from a subsidiary of Northwest Natural Gas. Harold E. Dittmer (HED) owns a majority beneficial interest in FCPLP. FERC originally certified the Fresno Project as a QF on January 26, 1988 (FERC docket number QF88-134-001). At that time the Fresno Project was entirely owned by a subsidiary of Northwest Natural Gas and had no electric utility ownership. Since 1994, it has been owned by Fresno Cogeneration Partners, LP. Since the time of its original FERC certification, the Fresno Project has been recertified once to reflect an ownership change. PG&E Corporation and its affiliate, Pacific Gas and Electric Company, are not affiliated in any way with any of the foregoing companies.

The Santa Maria Project was developed by Santa Maria Associates, LTD with Bonneville Pacific Corporation as its general partner. FERC originally certified the Santa Maria Project as a QF on February 11, 1986 (FERC docket number QF85- 644-000). In December 1994, Santa Maria Associates, LTD sold all of its rights and interest in the project to Santa Maria Cogen, Inc., the current owner. HED owns a majority beneficial interest in the Santa Maria Cogen Inc., or "Santa Maria." Since the time of its original FERC certification, Santa Maria has been recertified five times to reflect a combination of ownership changes, configuration changes, and the addition of an ice making facility. PG&E Corporation and its affiliate, Pacific Gas and Electric Company, are not affiliated in any way with any of the foregoing companies.

c. A detailed description of the historical operational performance of the project[s], including historical production and compliance with performance and efficiency monitoring standards.

The Fresno Project was the subject of a dispute over compliance with FERC-mandated operating and efficiency standards for the 1989 - 1991 operating years. As discussed in AL 2872-E, previous contract amendments resolved all disputes relating to compliance with operating and efficiency standards. PG&E has not taken any issue with Fresno's operating and efficiency standards since the current owner purchased the Fresno Project in 1994.

The Santa Maria Project has never had an issue related to compliance with FERC-mandated operating and efficiency standards. Every compliance check of Santa Maria that PG&E has conducted has demonstrated that the Santa Maria Project is in full compliance with all requirements related to operating and efficiency standards. Prospectively, the past performance of the Santa Maria Project is a moot point, since it will no longer be under contract to PG&E.

d. A summary of the proposed contract restructuring.

PG&E requests Commission approval to modify two existing PPAs totaling 33 MW. The Santa Maria PPA (for 8 MW) would first be assigned to Fresno, then terminated (although Santa Maria would remain obligated to be available for dispatch until some local transmission constraints affecting Fresno are removed). The Fresno PPA would be restructured. The restructured PPA will provide for the purchase of 33 MW of energy and firm capacity from Fresno (an increase of 8 MW from the current 25 MW) for a term commensurate with that of the remaining terms of the existing Fresno and Santa Maria PPAs. Fresno's PPA will otherwise expire on March 25, 2020, and Santa Maria's on September 10, 2019, while the proposed restructured PPA would expire on February 10, 2020.

The Amended and Restated PPA would also change energy payments to reflect Fresno's actual variable costs and provide PG&E a firm capacity payment discount and daily dispatch rights. In return, Fresno's owners receive energy payments that cover their variable operating costs and would no longer be required to maintain QF status.

e. A summary of the ratepayer benefits.

Ratepayers will benefit from the proposed contract restructuring through (1) the replacement of the must-take power obligation with an option for PG&E to dispatch the Fresno facility when Fresno's power is needed and is more economic than other alternatives, and (2) the reduction of the contract capacity payment.

Under the current PPA, the Fresno Project can operate to maximize its profit by operating as a baseload resource (24 hours per day, 7 days per week) when energy prices exceed its variable operating costs. When energy prices are less than operating costs, the Fresno project can limit operations to a 13-hours per day, 5 days per week basis (excluding holidays), providing peak electrical generation to PG&E's local 60 kV transmission system. Under the Amended and Restated PPA, PG&E states that dispatch rights of the Fresno project will add significant ratepayer benefit when compared to the must-take obligations of the existing PPAs. Reduced contract capacity payments will add additional value. Energy Division agrees that the reduced contract capacity payments will add additional value. PG&E's demonstration in AL 2872-E of the present value benefit attributable to the reduced capacity payments is acceptable.

However, Energy Division considers PG&E's modeling of the proposed energy benefits of the PPA restructuring to be over-valued, for purposes of calculating a shareholder incentive award. As stated in the advice letter, PG&E quantified the present value benefits of the contract restructuring "using a 'spark-spread' option model, which is a transformed variant of the Black option valuation model" (AL 2872-E, p.11).[7] This type of model creates a series of probabilistic outcomes or benefits. The probability that these benefits will all materialize exactly as modeled is extremely uncertain, yet PG&E has proposed to calculate the shareholder incentive based upon 10% of this project amount. We are not inclined to base a specific, deterministic shareholder incentive award on the uncertain, probabilistic calculations as submitted.

Instead, Energy Division recommends that the net ratepayer benefit of the energy portion of the contract restructuring be determined using a more traditional, deterministic approach, based on a comparison of heat rates. The existing heat rate for this contract is PG&E's short-run avoided cost (SRAC) heat rate. The new heat rate is the proposed, contractually specified heat rate, which is confidential. The operational energy cost difference between the two contracts, at comparable levels of operation and gas prices, represents a reasonable estimate of the net ratepayer benefit of the energy portion of the contract restructuring, rather than that proposed in the advice letter. Under this approach, the net ratepayer benefit of the energy portion of the contract restructuring would still be positive, but would represent (1) a more reasonable estimate of the expected net energy benefits that might actual materialize as a result of the contract restructuring, and (2) a significantly reduced amount relative to that calculated in the advice letter.

[7] The spark-spread is the difference between the market price of power at NP15, for example, and the cost of producing electricity from a generator.

As noted above, Energy Division agrees with the capacity payment benefits as submitted, but estimates lower energy benefits. As calculated by Energy Division, the total net ratepayer benefits, including net energy and capacity benefits, are 48.6% of the amount submitted in the advice letter. Thus, the total requested shareholder incentive award should be reduced to 48.6% of the amount requested in AL 2872-E.

f. A description of any significant, pending legal or regulatory disputes between the Utility and the QF, and their resolution or status.

There are no current or anticipated legal or regulatory disputes between the parties to this proposed PPA restructuring.

g. An assessment of the QF's projected economic and operational viability under the existing contract.

The Projects are both economically viable. PG&E projects positive income from their operation every year to the end of each PPA. PG&E concludes that the Projects are well maintained by examining their operating records over the past more than 15 years. Both projects have long-established records of making reliable firm capacity deliveries under their respective PPAs, and the projects have never been placed on probation under their current ownership.

h. A detailed description of ratepayer benefits, shareholder incentive, and sensitivity analyses.

Ratepayer Benefits. The Amended PPA has several benefits: the replacement of a must-take contract with a dispatchable contract; reduced heat rate relative to current SRAC; and reduced capacity payments.

Shareholder Incentive. The Amended PPA will terminate in 2020 and the aforementioned benefits will accrue over the intervening time period. Under the RALF process, the utility is eligible for a shareholder incentive reward for accomplishing the contract restructuring. To determine that amount, PG&E first calculated the present value of the benefits of the restructured contract as compared with a forecast of SRAC energy payments and contract capacity payments based on the expected future operation of the facility. Second, PG&E calculated 10% of that present value benefit amount as the shareholder reward.

As stated above, Energy Division accepts the net ratepayer benefit valuation associated with the reduced capacity payments, but considers PG&E's modeling of the proposed energy benefits of the PPA restructuring to be over-valued, for purposes of calculating a shareholder incentive award. Energy Division proposes to calculate the energy benefits as modeled as a comparison of heat rates at comparable gas prices. As noted above, the total net ratepayer benefits, including net energy and capacity benefits, are 48.6% of the amount submitted in the advice letter. Thus, the total requested shareholder incentive award should be reduced to 48.6% of the amount requested in AL 2872-E.

i. A copy of the QF's existing contract, including any amendments.

This information is attached to AL 2872-E as Appendix H, "Original Power Purchase Agreements, including all prior amendments and agreements executed at least three years prior."

j. A copy of the executed or unexecuted restructured agreement for which approval is sought and copies of all related agreements between the QF and the Utility.

This information is attached to AL 2872-E as Appendix A, "Amended Power Purchase Agreement including all prior amendments and agreements executed within the last three years."

DRA supports the contract restructuring

The RALF procedure requires that a statement of support or neutrality from DRA be attached to any restructuring Advice Letter filing. On August 1, 2006, DRA issued a letter in support for the contract restructuring, which is attached to AL 2872-E as Partially Redacted Appendix D – DRA Letter of Support. The DRA Letter of Support reflects the advice letter as filed. Upon review, Energy Division agrees that this is a beneficial contract restructuring; however, Energy Division recommends a reduction in the shareholder incentive amount as previous described.

COMMENTS

Public Utilities Code section 311(g)(1) provides that this resolution must be served on all parties and subject to at least 30 days public review and comment prior to a vote of the Commission. Section 311(g)(2) provides that this 30-day period may be reduced or waived upon the stipulation of all parties in the proceeding.

This is an uncontested matter in which the resolution grants the relief requested. Accordingly, pursuant to PU Code 311(g)(2), the otherwise applicable 30-day period for public review and comment is being waived.

FINDINGS

1. PG&E filed AL 2872-E on August 8, 2006 requesting approval of the amended and restated power purchase agreement between PG&E and Fresno Cogeneration Partners, L.P., pursuant to the Restructuring Advice Letter filing (RALF) procedure adopted in Decision (D.) 98-12-066.

2. In addition, PG&E requested approval of the two companion agreements (the Santa Maria Dispatch Agreement and the Consent to Assignment Agreement), that are part of the requested contract restructuring, as also filed in Advice Letter AL 2872-E.

3. AL 2872-E was not protested.

4. PG&E complied with the RALF requirements.

5. The reduced contract capacity payments associated with the PPA restructuring are a benefit to ratepayers and will add additional value; and PG&E's demonstration in AL 2872-E of the present value benefits of the change in capacity payments is acceptable.

6. PG&E's modeling of the proposed energy benefits of the PPA restructuring are over-valued for purposes of calculating a shareholder incentive award, as presented in AL 2872-E, and should instead be modeled as a comparison of heat rates at comparable gas prices.

7. The Amended and Restated PPA between PG&E and Cogen is reasonable.

8. The additional request of PG&E for approval of the two companion agreements (the Santa Maria Dispatch Agreement and the Consent to

Assignment Agreement), that are part of the requested contract restructuring, as also requested in Advice Letter AL 2872-E, should be approved.

9. PG&E should be authorized to recover all payments under the Amended and Restated PPA in PG&E's ERRA including an above-market portion in the Ongoing Competition Transition Charge (Ongoing CTC), or any other cost recovery mechanism subsequently authorized by the Commission, subject only to PG&E's prudent administration of the Amended and Restated PPA.

10. PG&E should be allowed to recover 10% of the net ratepayer benefits, based upon the estimate of the restructured PPAs as calculated by the Energy Division. This represents 48.6% of the shareholder incentive amount requested by PG&E in AL 2872-E.

11. AL 2872-E should be approved.

THEREFORE IT IS ORDERED THAT:

1. The request of Pacific Gas and Electric Company, regarding the amended and restated power purchase agreement between PG&E and Fresno Cogeneration Partners, L.P., pursuant to the Restructuring Advice Letter filing (RALF) procedure adopted in Decision (D.) 98-12-066, as requested in Advice Letter AL 2872-E, is approved.

2. The additional request of Pacific Gas and Electric Company for approval of the two companion agreements (the Santa Maria Dispatch Agreement and the Consent to Assignment Agreement), that are part of the requested contract restructuring, as also requested in Advice Letter AL 2872-E, is approved.

3. PG&E is authorized to recover all payments under the Amended and Restated PPA in PG&E's ERRA including an above-market portion in the Ongoing Competition Transition Charge (Ongoing CTC), or any other cost recovery mechanism subsequently authorized by the Commission, subject only to PG&E's prudent administration of the Amended and Restated PPA.

4. PG&E is authorized to recover 10% of the net ratepayer benefits, based upon the estimate of the restructured PPAs as calculated by the Energy Division,

which represents 48.6% of the shareholder incentive amount requested by PG&E in AL 2872-E.

This Resolution is effective today.

I certify that the foregoing resolution was duly introduced, passed and adopted at a conference of the Public Utilities Commission of the State of California held on December 14, 2006; the following Commissioners voting favorably thereon:

____
STEVE LARSON
Executive Director

MICHAEL R. PEEVEY
PRESIDENT
GEOFFREY F. BROWN
DIAN M. GRUENEICH
JOHN A. BOHN
RACHELLE B. CHONG
Commissioners

GHG Costs and Pre-AB32 Contracts

- Both CARB and the CPUC have recognized that contracts negotiated and executed before AB32 was effective which do not have a mechanism for GHG compliance cost recovery from the purchaser need to be addressed. Here's why that's important: :

  1. Since the amount of free allowances allocated to distribution utilities assumes the GHG from cogeneration projects under contract, without a seller cost recovery mechanism the recipient of free allowances will have a windfall benefit because they do not incur the costs that were assumed in that allocation of free allowances.

  2. As a result, consumers will not see the cost of GHG emissions thus removing the transparency that is intended to encourage consumers to modify their behaviors so as to reduce GHG emissions.

  3. Moreover, the purchasing utility's least cost dispatch decisions will result in higher GHG-emitting resources being operated because lower GHG-emitting resources will have a higher apparent cost due to the inclusion of GHG costs in their price

- In adopting cap & trade regulations, CARB acknowledged that such contracts need to be addressed but is hopeful that this will get resolved through negotiations between the applicable parties. The three categories of contracts that are potentially involved are:

  1. Contracts between GHG emitters and an electric distribution utility, such as Fresno Cogen

  2. Contracts between GHG emitters and an electric wholesale market participant

  3. Contracts between GHG emitters and their host under a CHP arrangement (the host may take delivery of thermal and/or electric energy)

- The CPUC has a proceeding to address the first group when the distribution utility is subject to CPUC jurisdiction. The proceeding was initially R.11-03-012, the GHG auction revenue allocation, but any consideration of the issue has been moved to R.10-05-006, the LTPPOIR

Fresno Cogeneration Partners, LP situation

- SO2PPA was executed in 1986
- Consistent with D.95-12-063 which sought to encourage QF contract restructuring, FCP entered into negotiations with PG&E.
- The amended agreement was executed by FCP on 5/1/2006 and by PG&E on 5/22/2006.

What does the CPUC need to do?

- In response to IEP's September 25th motion for expedited resolution of this issue (in the LTPP OIR), or otherwise, make it clear that proceeding will address the matter if negotiations are not successful within a very limited time frame (90 days should be more than sufficient given the narrow issue)
  - The CPUC should affirm that a contract does not have a mechanism for recovery of GHG costs if: 1) it is silent on the issue; AND 2) is not paid on a CPUC-approved methodology (e.g. avoided cost or CHP Settlement) or on a wholesale electric energy market index/basis.
  - The CPUC should set a date in mid-December for a Pre Hearing Conference on the status of negotiations and to set a schedule for the necessary proceeding. This is necessary to ensure the matter is resolved before the initial auction of GHG allowances.
- The CPUC should make it clear they agree with CARB that good faith negotiations have the potential to, and should, eliminate the problems that have been presented to the CARB (there should be no utility windfalls and there must be clear/transparent price signals of GHG costs to consumers and resource dispatchers) and that it supports CARB acting to solve the problems expeditiously if negotiations are not successful within a reasonable short period of time.
  - Wellhead/Fresno Cogen asks the CPUC to look closely at its proposal to CARB and consider supporting that simple administrative approach which solves all of the problems with CPUC jurisdictional contracts and sets a form of solution for the other pre-AB32 contracts (attached).