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July 17, 2008

BC HYDRO – 2008 LTAP EXHIBIT C13-2

B.C. Hydro and Power Authority
17th Floor
333 Dunsmuir Street
Vancouver, BC
V6B 5R3

Attention: Ms. Joanna Sofield, Chief Regulatory Officer

Dear Ms. Sofield:

Re: British Columbia Hydro and Power Authority ("BC Hydro") 2008 Long Term Acquisition Plan ("2008 LTAP)) ~ Project No. #3698514
Terasen Utilities Information Request No. 1 to BC Hydro

In accordance with the British Columbia Utilities Commission (the "Commission") Order No. G-96-08 establishing the Regulatory Timetable for review of the 2008 LTAP Application, attached please find the Terasen Utilities' (on behalf of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., and Terasen Gas (Whistler) Inc.), Information Request No. 1.

If you have any questions regarding this submission, please do not hesitate to contact Dave Perttula at (604) 592-7470.

Yours very truly,

on behalf of the TERASEN UTILITIES

Original signed by Shawn Hill:

For: Tom Loski

cc: Ms. Erica Hamilton, Commission Secretary, BCUC
cc (e-mail only): Registered Parties

REQUESTOR NAME: **Terasen Utilities**
INFORMATION REQUEST ROUND NO: **1**
TO: BRITISH COLUMBIA HYDRO & POWER AUTHORITY
DATE: July 17, 2008

PROJECT NO: 3698514

APPLICATION NAME: **2008 LTAP**

1.0 Reference: Market Assessment for Clean or Renewable Electricity

Exhibit B-1-1, Appendix H, Table 3-1 and Figure 3-2

Table 3-1 provides a state-by-state US WECC comparison of the target renewable energy volumes in 2010, 2015 and 2020 with the estimated 2008 existing renewable energy volumes. Figure 3.2 depicts the aggregate US WECC target renewable totals in these three years against the aggregate 2008 existing renewable energy total as indicative of the renewable energy potential.

1.1 How much of the differentials between the target renewable energy volumes in 2010, 2015 and 2020 and the existing 2008 renewable energy volumes are expected to be met for each state by new renewable resources from within the state boundaries?

1.2 Please confirm that the gap in Table 3-1 between the renewable resource requirements in 2010, 2015 and 2020 and the 2008 existing renewable resource quantity would be representative of the market potential that BC-based renewable electricity (or unbundled RECs) could be sold into. If not confirmed, what portion of the gap in these years is representative of the export market potential for BC renewable electricity.

1.3 How much does the possibility of selling unbundled RECs contribute to the market potential for BC-based renewable electricity?

2.0 Reference: Market Assessment for Clean or Renewable Electricity

Appendix H, p.11 and 12

In Appendix H, p.11 and 12 Global Energy cites simulation studies prepared by the California Energy Commission (CEC). Global Energy states:

"The CEC studies discussed in the above paragraph were performed by running hourly simulations of the WECC power grid, with hourly loads across WECC being served by economic dispatch of generation available in the region. In its "current conditions extended into the future" case, the CEC studies demonstrate the reality that much load in WECC is served by natural gas-fired generation. As the CEC increased penetration of renewables in the future in its alternative views of the future, the renewables will run to the meet the load, thereby displacing natural gas-fired generation that would otherwise be needed to meet loads. The CEC ran a few sensitivities with high GHG taxes in place. In the cases with high penetrations of renewables, economic dispatch would sometimes displace coal-fired generation rather than natural gas-fired generation because coal generation emits about twice the amount of GHG/kWh than

does natural gas-fired generation. The CEC concludes that a good way to reduce GHG is to reduce thermal generation levels by causing higher penetrations of energy efficiency and renewable power supplies."

2.1 Please confirm that BC is part of WECC and is interconnected with the western North American grid.

2.2 Please confirm that any electricity generated in B.C. that is surplus to domestic load requirements will be exported into the WECC interconnection.

2.3 Please confirm that much of the electricity load in WECC is served by natural gas-fired generation.

2.4 Please confirm that much of the electricity load in WECC is served by coal-fired generation.

2.5 Please confirm that the typical efficiency level for gas fired generation is approximately 50%, and the typical efficiency level for coal fired generation is lower than 40%.

2.6 Please confirm that adding renewables to the WECC grid to the meet load on the grid will tend to displace natural gas-fired generation or coal fired generation that would otherwise be needed to meet loads.

3.0 Reference: Market Assessment for Clean or Renewable Electricity

Exhibit B-1, Section 4.5 and Pacific Gas and Electric (PG&E) Feasibility Study of Importing Renewable Power from British Columbia to California

3.1 Please confirm with PG&E that it prepared and filed the attached report, entitled “BC Renewable Study Phase 1” with the California Public Utilities Commission.

Pacific Gas and Electric Company®

Janet C. Loduca
Director
Energy Proceedings

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June 20, 2008

Mr. Sean Gallagher
California Public Utilities Commission
Energy Division
505 Van Ness Avenue
San Francisco, CA 94102-3298

Ms. Dana Appling
Executive Director
Division of Ratepayer Advocates
505 Van Ness Avenue
San Francisco, CA 94102-3298

Dear Mr. Gallagher and Ms. Appling:

In Decision (D.) 07-03-013 in the *Application of Pacific Gas and Electric Company (PG&E) for Recovery of Generation Feasibility Study Costs Associated with the Evaluation of Wind-Generated and Other Renewable Electric Power in British Columbia* (A.06-08-011), approved on March 1, 2007, the CPUC orders PG&E, upon completion of Phase 1, to provide "an explanation of the decision to continue with Phase 2 or to discontinue the BC Renewable Study."

Pursuant to D.07-03-013, below is PG&E's explanation of its decision to pursue Phase 2 of the BC Renewable Study.

PG&E would be glad to answer any questions you have related to this report. If you have any questions, you may contact Alice Harron at (415) 973-3662.

Sincerely,

/s/

Janet C. Loduca
Director
Energy Proceedings

Pacific Gas and Electric Company
BC Renewable Study Phase 1

On March 1, 2007, the California Public Utilities Commission ("CPUC") approved D.07-03-013, which grants Pacific Gas and Electric Company ("PG&E") the authority to recover up to $14 million for external consultants to study the feasibility of obtaining renewable power from various regions in British Columbia ("BC") and the potential to transmit this power to PG&E's service area.[1] The potential for a power purchase agreement ("PPA") with BC Hydro and/or Powerex and the transmission line from BC to California ("CA") will be called the Project for the purposes of this paper.

Under the CPUC Application (A.) 06-08-011 and Decision (D.) 07-03-013, the BC Renewable Study is divided into two phases. The purpose of Phase 1 is to study the feasibility of: (a) obtaining economic, commercially viable renewable generation from BC; and (b) building a transmission line from BC to CA. Phase 2 consists of generation procurement and transmission development activities.

In D.07-03-013, the CPUC orders PG&E, upon completion of Phase 1, to provide "an explanation of the decision to continue with Phase 2 or to discontinue the BC Renewable Study."[2] The purpose of this paper is to explain PG&E's decision to pursue Phase 2.

During Phase 1 (between March 2007 and May 2008), PG&E:

a. estimated the amount and cost of future generation resources (see Part I, "Generation Resources");
b. studied the feasibility of building a transmission line from BC to CA (see Part II, "BC-CA Transmission Line Feasibility");
c. considered the costs and benefits of various ownership alternatives for the transmission line (see Part III, "Cost and Benefits of Various Transmission Ownership Alternatives and Regulatory Arrangements");
d. reviewed potential commercial arrangements (see Part IV, "Commercial Structure Assessment");
e. evaluated commercial viability, including the potential for executing a letter agreement (see Part V, "Commercial Viability");
f. reviewed BC's regulatory climate (see Part VI, "Regulatory Environment in BC");
g. assessed CA's regulatory and legal impediments (see Part VII, "CA Regulatory and Policy Impact on Project");
h. studied wind integration ability (see Part VIII, "Ability to Integrate Resources"); and
i. compared the Project with other potential renewable sources (see Part IX, "Economic Analysis").[3]

[1] From inception through April 30, 2008, PG&E has spent $3.8 million on external consultant costs which have been recorded in the British Columbia Renewable Study Balancing Account. Once all invoices have been received, PG&E forecasts $5.2 million to complete Phase 1.
[2] D.07-03-013, Ordering Paragraph (OP) 4.
[3] Source reflects an evaluation that includes cost of generation and the transmission line to transport to a load center in CA.

There is a strong complementary relationship between the seasonal demands of summer-peaking CA and winter-peaking BC. This relationship provides a foundation for mutual benefit. Developing new renewable generation resources in BC and strengthening transmission links in the region will support BC's self-sufficiency policy as well as help meet BC and CA's environmental and energy objectives.

Given the vast amount of potential renewable resources in BC, the strong feasibility of building a transmission line, good indicators of commercial viability, and the results of economic analyses, PG&E has decided to proceed to Phase 2 of this Project, including pursuit of discussions with Powerex and transmission development activities. PG&E will institute some action items for Phase 2, including monitoring progress to determine whether to continue the Project during Phase 2. (See Part X, "Decision".)

I. Generation Resources

Amount of Potential Renewable Generation

British Columbia has a large amount of potential renewable generation that is well in excess of its own needs to serve its forecasted load. The table below illustrates the amount of renewable generation potentially available in BC by 2016. This estimate represents an aggregated range of identified potential, which takes into account environmental and permitting issues. It does not, however, identify any particular project or express an opinion regarding any particular project's ability to meet the requirements of environmental and other provincial permitting processes.

Generation Source	Amount that Could Be Available by 2016		Amount of Potential Energy by 2016		Net Capacity Factor	Potential Beyond 2016
Units	MW		(GWh/Yr)		%	MW
Run-of-River Hydro	3,100	6,150	12,500	24,700	46%	4,480
Wind	4,400	10,300	11,500	26,900	30%	1,500
Biomass	700	700	5,200	5,200	85%	820
Geothermal	100	100	800	800	90%	600
Totals	**8,300**	**17,250**	**30,000**	**57,600**	--	**7,400**

Methodology

PG&E's consultant, Global Energy Concepts ("GEC") conducted an in-depth analysis of the potential wind, small run of river ("ROR") hydro, biomass and geothermal renewable generation.

GEC developed wind energy capacity and energy production estimates. It assessed and evaluated past studies and commissioned creation of improved wind resource maps. GEC performed regional field assessments and developed regional estimates of generating potential. GEC incorporated wind resource estimates to calculate energy potential and developed regional cost estimates.

Numerous independent power producers' ("IPP") ROR hydro power projects are in various stages of investigation and development in BC. GEC and its subcontractor R.W. Beck took two approaches to understand the extent of new ROR hydro development. First, GEC's team compiled an inventory of current permitting activities

for hydro projects. Then, GEC's team contacted IPPs and their consultants to obtain information regarding their development plans.

To estimate biomass development, GEC's team reviewed available BC biomass assessment reports. GEC's team also held extensive conversations with key BC biomass developers, BC forestry government officials, and the Council of Forest Industries (a trade organization representing BC's forest industries) to obtain the most current and in depth understanding of issues surrounding biomass generation. Based on compilation of current information, GEC's team created possible future development scenarios regarding fuel type, quantity, combustion technology, and performance parameters to derive its independent estimate of future development potential.

To estimate geothermal development potential in BC, GEC subcontracted with GeothermEx (one of the largest and most experienced geothermal energy consulting companies in the Western Hemisphere). GeothermEx supports and monitors geothermal development activities within BC as part of its regular business activities.

Because current detailed geothermal resource analysis reports are not available for BC, the estimates for potential geothermal generation development are based on GeothermEx's experience and first hand knowledge of BC. In conducting the work, GeothermEx also consulted with geothermal project developers that have historically been active in BC to obtain additional information.

II. BC-CA Transmission Line Feasibility

PG&E's objective in Phase 1 is to confirm whether there are one or more feasible corridors for locating high-capacity electric transmission lines, and to develop sufficient cost and schedule information to support the decision-making process as to whether to proceed with Phase 2. These transmission corridors would need to accommodate a new high-capacity electric transmission line between BC and Central CA, which could consist of either an inland alternating current ("AC") or direct current ("DC") line, or a coastal submarine DC line.

An overland transmission line from British Columbia to California is technically (engineering and construction) and environmentally feasible. Developing a new transmission line through Washington and Oregon would encounter some land use and environmental challenges, but these would be within a manageable level. Routing a transmission line through northern California, while feasible, may involve significant environmental mitigation.

From a technical perspective, the submarine cable option does not meet the project objectives to meet 2016/2017 on-line date nor is it capable of transmitting 1,500 MW. Additionally, the existing worldwide manufacturing and installation capability for submarine cable is not sufficient to support the project. In addition, the submarine cable option is more expensive on an installed $/MW basis than the overland option.

III. Cost and Benefits of Various Transmission Ownership Alternatives and Regulatory Arrangements[4]

Decision 07-03-013 requires PG&E as part of its BC Renewables Study to review the costs and benefits of various ownership alternatives and regulatory arrangements for the transmission line from BC to CA.[5, 6] In 2007, in accordance with the Western Electricity Coordinating Council ("WECC") procedures, PG&E conducted a Regional Planning process that included substantial stakeholder outreach regarding the planning of the transmission project, and PG&E filed a final report on the process with WECC. PG&E also initiated the first of a three-phase WECC Project Path Rating Review process. The objective of the WECC Phase 1 effort is to determine: (1) a preliminary plan of service including intermediate terminations and transformation facilities, and (2) the non-simultaneous ratings of the various line segments in the preliminary plan of service. This activity is well underway, and PG&E expects that WECC Phase 2 efforts will begin later this year.[7] All of these activities have been overseen by a Steering Team comprised of the five transmission-owning utilities whose service footprints could be traversed by the proposed transmission line.[8]

PG&E is also participating in a Transmission Coordination Working Group ("TCWG"), established in January 2008 to coordinate the planning study efforts for eight transmission projects in the Pacific Northwest.[9] The proposed transmission line from BC to CA is one of these eight projects.

Because transmission line development is in its formative stages, it is still early to definitively address issues of costs and benefits, the role that any regional transmission organization might have in the operation and control of the line, and/or tariff structure. PG&E is an active member of the Steering Team, and is working through these issues with them. There has yet to be a final determination regarding the transmission line's configuration, or ultimate location of its interconnection points.

Nevertheless, PG&E can offer observations on the implications of various ownership alternatives and regulatory arrangements. Preliminarily, no ownership alternative has been shown to make building a transmission line infeasible. Under a multiple-owner scenario, geographically relevant project owners/partners could provide expertise and other benefits to siting a transmission line through multiple states. To the extent that any portion of the line would be included in the California Independent System Operator ("CAISO") Controlled Grid, access to that portion of the line would be governed by the CAISO Tariff. As to portions of the line not operated and controlled by a regional transmission organization, and assuming that the line owner(s) is a FERC jurisdictional utility, access to the line would be governed by the terms of an Open Access

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[4] See Section II above ("BC-CA Transmission Line Feasibility") for a discussion of transmission costs and hurdles to the development of alternative routes which allow delivery of energy into California.

[5] Decision 07-03-013, OP 2.b.

[6] Note that as to transmission costs, PG&E filed for and obtained cost recovery for transmission development activities from FERC. 123 FERC ¶ 61,067 (issued April 21, 2008).

[7] Relevant materials are posted at http://www.pge.com/canada/.

[8] Current Steering Team members are: PG&E, Portland General Electric, PacifiCorp, Avista, and the British Columbia Transmission Corporation.

[9] TCWG materials are posted at http://www.nwpp.org/tcwg/.

Transmission Tariff ("OATT").[10] The owner of such portions of the line would, as a Transmission Provider, offer non-discriminatory access to others under the terms of an OATT.

IV. Commercial Structure Assessment

PG&E reviewed the following potential contractual structures to facilitate the purchase and transport of renewable generation from BC to CA:

1) PG&E to contract directly with Canadian IPPs to obtain generation and transport to the US/Canadian border;
2) PG&E to form a Canadian joint venture company with an entity such as BC Hydro and/or Powerex with the joint venture company contracting with developers to obtain generation within BC and transport to the US/Canadian border;
3) PG&E to acquire and manage generation assets in BC for transport to the US/Canadian border; and
4) PG&E to contract directly with an entity such as BC Hydro and/or Powerex to obtain generation and transport to the US/Canadian border.

PG&E reviewed each potential transaction structure in the context of obtaining benefits to the parties to the transaction as well as the ability to transact under that structure.

Based on that review, PG&E believes that the fourth alternative of contracting directly with an entity such as BC Hydro and/or Powerex through a power purchase agreement to deliver an all-in product at the US/Canadian border is the most viable option to obtain renewable generation. PG&E would transport from the US/Canadian border to CA.

V. Commercial Viability

<u>Pilot/ Letter Agreement</u>

PG&E's application (A.06-08-011) proposed a pilot to help demonstrate the feasibility of procuring, firming, and transmitting renewable energy from BC to CA. Through discussions as part of this feasibility study, Powerex and PG&E have determined that a non-binding Letter Agreement is the appropriate mechanism under which to pursue additional discussions about the feasibility of reaching a possible future commercial arrangement between PG&E and Powerex, including further evaluation of the benefits to the respective parties and jurisdictions.

The Letter Agreement, while non-binding, covers a much greater scope of the Project than the pilot transaction. Having the agreement to work though issues for the full scope of the Project as opposed to a small trial transaction provides a foundation for continuing to Phase 2 of the Project.

[10] FERC adopted terms of and conditions for jurisdictional utilities' pro forma OATTs in Order Nos. 888, 889, and 890.

The Letter Agreement delineates the commitments of PG&E and Powerex to explore and evaluate structures for possible future commercial arrangements between PG&E and Powerex for sale of renewable energy that is in the interest of both jurisdictions.

Standard Firming Product

Decision 07-03-013 requires PG&E to pursue a standard firming service from BC.[11] At the time of the decision, PG&E was just beginning discussions with various BC entities regarding aspects of the Project. PG&E explored the possibility of an unbundled firming/shaping service. However, it became apparent that an "all-in" contract for purchase of renewable power at the US/Canadian border was the most desirable approach.

VI. Regulatory Environment in BC

BC's electricity industry comprises a mix of private and government-owned companies. (Government-owned companies are known as Crown Corporations.) BC Hydro, a Crown Corporation,[12] serves roughly 90 per cent of the Province. BC Hydro is also the buyer for virtually all of the electricity generated by IPPs in BC.

BC Hydro's position as a Crown Corporation means the Province's electricity industry is tightly linked with the public policy objectives of the provincial government.

The Energy Plan,[13] released in February 2007 by the BC Government, set a clear direction for the BC electricity sector, emphasizing environmental protection, conservation, and energy security—the last point being made manifest through a requirement for provincial self-sufficiency. In May 2007, the Premier of British Columbia and the Governor of California signed a Memorandum of Understanding that commits the two jurisdictions to adopt policies to create more renewable energy development and transmission. In September 2007, the Premier's Technology Council recommended that BC target exporting renewable generation by 2020.

VII. CA Regulatory and Policy Impact on Project

CA regulations concerning the eligibility of generation from out-of-country renewable energy resources to meet CA's Renewable Portfolio Standard ("RPS") requirements have an enormous impact on the commercial viability of the Project. While 2016 is eight years away, PG&E will describe how some of CA's current rules affect the commercial viability of the Project. Some of these rules must be modified for the Project to succeed.

The key obstacle to project success that must be modified by legislation is the definition of new small hydro generation. So long as BC small hydro generation requires balancing and shaping, the non-RPS eligibility of BC ROR hydro affects not only

[11] Decision 07-03-013, OP 2.d.
[12] The Province of British Columbia owns BC Hydro and BC Transmission Corporation ("BCTC") ("Crown Corporations."). Each entity has its own Board. The Province as shareholder appoints members of each of the Boards. Powerex is a wholly owned subsidiary of BC Hydro.
[13] The BC Energy Plan: A Vision for Clean Energy Leadership

counting the generation towards RPS goals but also potentially affects the Project's economics under current and future State Green House Gas ("GHG") rules.

As described below, RPS eligibility affects the cost for GHG compliance under both AB 32 and SB 1368. Shaping and banking non-RPS-eligible projects could lead to (1) added costs for retiring GHG emission allowances for system energy at default emission rate; and (2) not using system energy to bank and shape.

Renewable Portfolio Standard (RPS) Eligibility

Facilities located outside of the United States, such as those that would be part of the proposed Project, must satisfy these three criteria:

1. Out of Country Eligibility;
2. Resource Eligibility; and
3. Delivery Eligibility.

1. Out of Country Eligibility

To be certified by the California Energy Commission (CEC) as RPS eligible, a renewable energy generator located outside of the United States must be shown to be "… developed and operated in a manner that is as protective of the environment as a similar facility located in the State."[14] In this case, the developer must show that the laws, ordinances, rules, and statutes (LORS) governing the generation facility in BC will protect the environment to the same extent that the relevant LORS in CA would govern a similar facility located in CA.[15]

While the eligibility of any particular out-of-country facility will not be known until it is submitted for RPS certification, PG&E believes that BC laws, regulations and protocols for the types of generation it reviewed, (e.g., wind, biomass) are as protective of the environment as those of California. All indications are that the CEC should find that the applicable BC LORS will result in the development and operation of a project that is as protective of the environment as an equivalent CA development and approve BC projects as out-of-country compliant for RPS eligibility.

2. Resource Eligibility

Based upon PG&E's initial research, BC ROR hydro facilities would not be qualified as RPS eligible resources. Under California legislation, hydro generation facilities are RPS-eligible if they meet all of the following criteria:

- Do not cause a change in volume or timing of stream flow;
- Are less than or equal to 30 MW; and

[14] Public Resources (Pub. Res.) Code section 25471(b)(2)(B)(v).
[15] Guidebook p. 40, "3. Instructions for additional Required Information for Out-of-State Facilities."

- Do not cause an adverse impact on instream beneficial uses.[16]

BC ROR Hydro facilities will not meet any of these criteria.[17] However, it may be argued that a different streamflow requirement and an increase in the maximum capacity limit may be warranted due to different circumstances in BC, and that the disqualifying impact on instream beneficial uses should be limited to significant adverse impacts to allow reasonable hydroelectric development to be RPS-eligible. Thus far, PG&E's consultants have found that ROR projects do not have major impacts on the overall environment of the watershed. Because the current standards for the eligibility of hydroelectric generation are the consensus result of a coalition effort, new efforts to qualify hydroelectric generation in BC for the RPS must be closely coordinated with these identified stakeholders.

3. Delivery Eligibility

Renewable energy generation must be delivered to CA before it can fulfill RPS requirements. Under State statute and the CEC's implementation rules, the out-of-state eligible renewable resource generation may be banked and shaped into firm deliveries at a time other than generation. The later delivery, bundled with the green attributes of the renewable generation, will be RPS eligible.

<u>GHG Emissions</u>

The fact that new BC small hydro is currently not RPS eligible and will need to be banked and shaped by system energy during certain periods may create a potential GHG emissions compliance cost issue under AB 32. System energy used to bank and shape small hydro may be assigned a default GHG emissions rate, because the deliveries will not be considered renewable. PG&E or the seller may incur AB 32 compliance costs to acquire and retire "GHG emissions allowances" equivalent to the default emissions assigned to the transaction during the periods when system energy is used to bank and shape the small hydro.

In addition, SB 1368 may create restrictions on the ability of new BC small hydro to use system energy for banking and shaping. Small hydro is not RPS eligible and therefore system energy used to bank and shape it may be considered baseload energy that is subject to SB 1368's restrictions, potentially precluding the use of the new BC small hydro as part of the Project.

If, due to legislative amendment, new BC small hydro did become RPS eligible and was banked and shaped, the delivered energy would be considered renewable. PG&E would not need to retire allowances at the default emissions rate for these deliveries. PG&E could use system energy to shape BC small hydro under SB 1368 as well.

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[16] CEC regulations state that an adverse impact on the instream beneficial uses may be found if the facility causes an adverse change in the chemical, physical, or biological characteristics of water. CEC RPS Eligibility Guidebook, Third Edition (Guidebook), p. 34, "8. Capacity."

[17] There may be a certain amount of potential BC ROR hydro facilities that are less than 30 MW but not the majority of projects.

Separately, preliminary indications are that the economics of out-of-state biomass and geothermal generation can be improved if it can be banked and shaped. However, the CPUC's separate GHG emissions performance standard rules under SB 1368 do not allow substitute energy to be delivered in place of baseload generation, such as biomass-fired and geothermal generation. While such banking and shaping of biomass and geothermal baseload resources would be beneficial for the BC Project, the magnitude of such benefits is within the uncertainty of the overall Project economic analysis.

CPUC Non-Modifiable Standard Terms and Conditions

The CPUC Standard Terms and Conditions decision requires that all RPS PPAs be governed by California law (D.07-11-025). This requirement is included in a non-modifiable standard term. As noted above, PG&E believes that a transaction with an entity such as BC Hydro and/or Powerex is the most viable option. Both BC Hydro and Powerex have the ability to agree to CA law on issues relating to the PPA. However, this issue may raise potentially significant concerns and will be further discussed in Phase 2.

VIII. Ability to Integrate Resources

The very preliminary conclusion is that it appears that it could be technically feasible to integrate and shape volumes of wind used in the economic analysis. However, further study is needed to identify potential operational constraints on the BC Hydro system. Costs associated with such integration need further analysis and discussion with BC Hydro. BC Hydro will be conducting a much more in-depth wind integration study scheduled to be completed by the end of 2008. PG&E will update information for its analysis during Phase 2.

IX. Economic Analysis

The primary conclusion of this economic analysis is that BC potential renewable generation is within the range of other options on a delivered cost basis to CA. The following assumptions can readily change the attractiveness of the Project relative to other renewable alternatives:

- Cost of renewable generation alternatives to California;
- BC Hydro's ability and cost to shape;
- Transmission capital cost;
- Amount of MW available in alternate regions; and
- Various government incentive extensions.

The economics of British Columbia renewables should continue to be reevaluated as the price and availability of resources and the cost of delivery become more certain.

X. Decision

Given the vast amount of renewable resources in BC, the strong feasibility of building the transmission line, good indication of commercial viability (including ability to firm and shape), and the results of the economic analysis, PG&E has decided to proceed to Phase 2 to pursue discussions with Powerex and to conduct preliminary transmission development work.[18]

Action Items for Phase 2

PG&E will take the following actions during Phase 2:

1) Establish milestones to determine whether to pursue the Project throughout Phase 2. Examples are:
   a) Demonstrate progress of discussions with Powerex;
   b) Monitor and review BCTC transmission planning efforts and BC Hydro calls for energy;
   c) Refresh economic analysis periodically (up through earlier of execution of PPA or termination of Project) with updated information; and
   d) Target execution of PPA with Powerex by 2010.
2) Work with CA policymakers on RPS eligibility for small hydro;
3) Continue to consult with CPUC on Project's progress; and
4) Continue consultant contracts to monitor regulatory matters, provide technical support (e.g., resource cost, wind integration) and support economic analysis.

[18] As noted above, PG&E filed for and obtained cost recovery for transmission development activities from FERC. 123 FERC Section 61,067 (issued April 21, 2008).