Final Report on BC Hydro's Energy Procurement Practices

Final Report of

Merrimack Energy Group, Inc.

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Executive Summary

Merrimack Energy was asked by BC Hydro to conduct an independent inquiry into the energy procurement practices of BC Hydro, with particular emphasis on the interactions with energy suppliers. The objective of this evaluation is to (i) assess current procurement practices and identify areas for improvement (ii) assess how those practices compared to well-respected procurement practices elsewhere in the utility community and whether improvements could be made to achieve "best in class" performance. In addition, the assignment included an assessment of the relationship between BC Hydro and its energy suppliers. Again, suggesting areas for potential improvement was a part of the assignment.

The energy procurement practices review addressed the following functional areas within the overall energy procurement function: (i) Energy demand and supply planning; (ii) Sourcing and procurement; (iii) Project interconnection; (iv) Evaluation and risk allocation and (v) Contract management and payment administration.

To conduct this assessment, Merrimack reviewed a large variety of relevant written materials pertaining directly to BC Hydro's energy procurement practices, including prior procurement documents, specimen and executed electricity purchase agreements (EPAs), reports on prior procurement activities, relevant laws, public policy documents regarding First Nations and various stakeholder reports and recommendations. Input from stakeholders and First Nations was received through face-to-face and telephone interviews, as well as the distribution and review of survey questionnaires soliciting comments from stakeholders and First Nations on a wide range of related topics associated with BC Hydro's energy procurement processes. Merrimack Energy received fourteen responses to the survey questionnaire and conducted over twenty-five interviews.

Simultaneously, the procurement practices and documentation of a select number of other utilities in Canada and in the United States were reviewed and analyzed. In particular, procurement contracts for other utilities were reviewed for comparison with BC Hydro's EPAs.

During the interviews and surveys, stakeholders and First Nations were asked to identify the strengths and weaknesses of BC Hydro's energy procurement process. A brief summary of the results is provided in Exhibit ES-1.

Exhibit ES-1: Strengths and Weaknesses of BC Hydro's Energy Procurement Process

Strengths	Weaknesses
• BC Hydro credit rating • Long term contracts • BC Hydro has run fair and clear calls • Fair and reasonable contract management • Post award reports • EPA is financeable • Interaction with suppliers in the design of calls • Meetings with bidders before bid submission	• Process is not transparent • Information provided to bidders is not adequate • Irregular timing for procurements • Risk allocation in EPA is sub-optimal • Evaluation criteria do not reflect project viability • Too much emphasis on price in selecting winning bids • Two resources, wind and hydro, have dominated contract awards

In addition, for purposes of assessing the most critical issues associated with the energy procurement process, Merrimack Energy compiled the responses from the stakeholders and First Nations within each functional category, identified the most frequently mentioned issues of substance, and developed a list of questions for follow-up discussions with stakeholders and First Nations at a workshop organized by Merrimack Energy to assess these issues in more detail. During the December 2010 workshop, Merrimack Energy also identified procurement practices of other utilities as part of the information exchange.

A summary of the issues for discussion at the workshop, as framed by stakeholders and First Nations, included the following:

Energy Demand/Supply Planning

1. The results of the IRP should play a role in shaping BC Hydro's Energy Procurement practices and processes;
2. The IRP should consider both domestic and foreign supply and demand;
3. The IRP should address allocation of resources between BC Hydro and IPPs;
4. Administrative review of the IRP must be implemented before its chances of succeeding can be evaluated;
5. The IRP should consider whether the procurement of green resources in a system like BC Hydro should proceed irrespective of cost and ratepayer benefit.

Sourcing and Procurement

1. Procurement activities will benefit from processes that are smaller and more frequent;
2. BC Hydro's procurement process is not very transparent;

3. BC Hydro's evaluation methodology focuses on the lowest price and does not give adequate weight to project/bidder viability;
4. An RFP process is generally the preferred process;
5. Uncertainty with the timeframe for undertaking and completing a solicitation is troublesome for bidders.

Generator Interconnection

1. The entire interconnection process has to be revisited but the effort to integrate BC Hydro and BCTC is viewed as a positive;
2. The issue of concern to IPPs is the impact of the cost of interconnection and transmission on bid evaluation and ranking;
3. Interconnection request data forms may be onerous at the feasibility stage. BC Hydro should just ask for generic data at this stage.

Evaluation and Risk Allocation

1. The EPA is intended to shift risk from the buyer to the seller who is expected to price risk competitively;
2. Not all project risks are equally manageable and the risk premiums for risks that are outside the reasonable control of the Sellers may be high;
3. Pricing of intermittent resources on the basis of strict seasonal delivery requirements is not a common characteristic of power contracts for such resources;
4. Seasonal pricing and financial penalties for the first MWh of under-or over-delivery create significant financial risk for the Sellers;
5. The five-year adjustment clause for seasonally firm energy can push revenues down dramatically;
6. The First Nations risk rests with the Sellers.

Contract Management and Payment Administration

1. Suppliers with contracts are very pleased with contract management activities;
2. Suppliers laud BC Hydro's spreadsheet to keep track of billing and metering and indicate BC Hydro has a good support team to deal with counterparties;
3. Overall, the contract management function works well

Interaction with Suppliers

1. BC Hydro ranks highly in most activities associated with procurement design, workshops, and bidder engagement prior to issuance of the RFP but poorly as far as post bid receipt is concerned.

While the workshop served to confirm the issues already identified, a few other issues emerged, including the establishment of standards for evaluating bilateral contracts and the assessment of different bid evaluation methodologies. The final recommendations reflect the discussion on the initial and the additional issues raised at the workshop. In addition, the recommendations also reflect Merrimack Energy's review and assessment of the energy procurement practices of other similarly situated utilities.

Recommendations

Energy and Demand Supply Planning

1. Link the Integrated Resource Planning process (IRP) and procurement activities, i.e. the timing and level of need for new resources should be determined through the IRP process, and assure that the IRP:
    a. is consistent with government policy;
    b. identifies opportunities for procurement;
    c. is the vehicle to conduct analyses regarding inputs and assumptions underlying the procurement process; and
    d. is updated as frequently as necessary to prevent over or under supply.

Sourcing and Procurement

2. Make the Energy Procurement process more transparent for all stakeholders and First Nations:
    a. Prepare Energy Procurement procedures, as well as a Code of Conduct, for undertaking procurement processes and post both on the website;
    b. Develop project viability criteria and transparent weightings for price and non-price factors to evaluate bids in select procurements.

3. Implement smaller but more frequent energy procurements in the future which are linked to the IRP, as updated, to accomplish the following objectives:
    a. Provide more certainty to the market regarding procurement activity;
    b. Allow for quicker adjustment to market and governmental policy changes;
    c. Encourage suppliers to maintain project development activity to create a more competitive market.

4. Continue to follow the recent trend in BC Hydro's procurements, combining or mixing procurement vehicles to match the type of overall solicitation being implemented:
    a. Utilize a more flexible Request for Proposals (RFP) process for larger and broader (province-wide) solicitations;
    b. Continue to implement other procurement vehicles such as Call for Tenders, Request for Offers, or Feed-in Tariffs for smaller or targeted resources as required.

5. For larger procurement processes, utilize a multi-stage evaluation process which includes the following stages:
    a. Threshold process for eligible offers;

b. Indicative bid process combined with project viability criteria to select a short-list;
c. Best and final price offer for final bid selection;[1]
d. Simultaneous competitive negotiations that allow for consideration of value-added provisions such as buyout options and expiration transfers under standards which assure fairness.

6. Develop standards for evaluating and negotiating bilateral contracts and make the standards transparent to stakeholders.

7. Consider creating an Advisory Group comprised of non-supplier stakeholders and First Nations to advise BC Hydro on procurement activities. The Advisory Group would likely be comprised of stakeholders and First Nations from the IRP working group. This is similar to the Procurement Review Group utilized in California as an advisory group only for energy procurement activities.

Interconnection

8. In the process of integrating BC Hydro and BCTC, assess how other utilities are addressing the following issues:
    a. Providing information about the availability of transmission capacity and estimated costs to expand capacity in different regions/delivery points (e.g. PacifiCorp and California utilities);
    b. Considering cluster studies by region (e.g. Southern California Edison);
    c. Developing final portfolios of projects from procurements based on bid price, interconnection and transmission upgrades (e.g. Hydro-Quebec).

Evaluation and Risk Allocation

9. Complete a financial analysis, in collaboration with stakeholders and First Nations, to assess if more flexible contract provisions, which shift less risk to the supplier than the following EPA provisions, achieve a better balance of costs and benefits to ratepayers. If the analysis does suggest a better balance will occur, modify the contract provisions for better alignment with prevailing industry practices:
    a. The five year ratchet provision adjusting "full-price" delivery levels down to levels exceeded in 80% of the performance periods;
    b. Financial penalties for over or under delivery from the first MWh;
    c. Pricing intermittent resources on the basis of strict seasonal delivery requirements.

[1] The indicative bid/best and final offer process would allow the supplier to incorporate market or project cost changes in its best and final bid. In addition, this process can be effectively integrated with the interconnection process to ensure that interconnection cost information included in system impact studies and possibly facility studies can be incorporated in final bid prices.

I. Background

A. Introduction

In early September 2010, BC Hydro initiated a review of its energy procurement and contract management practices in conjunction with a corporate-wide review of procurement practices relating to other materials and services. Based on the unique nature of energy procurement, BC Hydro has decided to conduct the Energy Procurement review on a separate track from procurement of other services and materials.

The Energy Procurement review has the following objectives:

- Review and assess current procurement practices
- Achieve best-in-class procurement practices
- Strengthen BC Hydro's relationships with energy suppliers
- Provide a strategic vision for undertaking and structuring future procurement processes.

In addition, the Energy Procurement review is being conducted in three phases:

1. Phase 1 – internal review by BC Hydro of past assessments, engagement feedback, summary of future procurement trends and identification of potential areas of focus for the independent consultant tasked with performing Phase 2;

2. Phase 2 – review by independent consultant with solicitation of input from energy suppliers and other stakeholders and First Nations plus comparison with procurement practices in other jurisdictions;

3. Phase 3 – development of an action plan and implementation strategy.

For this assignment, BC Hydro commissioned Merrimack Energy Group, Inc. ("Merrimack Energy") to undertake the Phase 2 tasks. The following specific tasks were undertaken by Merrimack Energy during the review:

- Conduct a review of BC Hydro's existing energy procurement and contract management practices, including the initial areas of focus identified by BC Hydro, as well as other areas that are deemed as being important to developing best in class performance;

- Employ a higher-level strategic perspective in reviewing BC Hydro's energy procurement practices placing particular emphasis on how BC Hydro engages with its energy suppliers;

- Review previous input and procurement reviews by BC Hydro as well as review feedback from stakeholders provided to the BC Government during the Green Energy Advisory Task Force;

- Solicit input from IPP suppliers, First Nations, other stakeholders, contract holders, and the BC Government;

- Assess and compare findings against best practices procurement approaches in comparable jurisdictions (e.g. similar policies and regulatory oversight) across North America to identify areas for both maintaining current practices and identifying areas of improvement.

Merrimack Energy has had significant experience working with utilities, utility Commissions and IPPs on a range of competitive procurement processes throughout North America. Merrimack Energy has served in the role of Independent Evaluator, Independent Monitor, Fairness Advisor and outside consultant for over 60 procurement processes in 19 states and 3 Canadian Provinces. Our assignments have focused on a full array of resource options including renewable resources, conventional resources, distributed resources, demand response, and demand-side management options. Merrimack Energy has served as independent consultant for all of Hydro-Quebec's Call for Tenders, as Independent Evaluator for renewable solicitations for Southern California Edison, Pacific Gas and Electric, Arizona Public Service Company, Avista Utilities, and PacifiCorp, and on the Fairness Advisor team for two Ontario Power Authority solicitations.

B. BC Hydro Procurement Activities

BC Hydro has solicited and procured energy resources via a Call for Tenders ("CFT") or Request for Proposals ("RFP") process for a number of years. Recent procurement processes reflect lessons learned over time in undertaking past solicitations and have been shaped by regulatory and policy directives in the Province.

Since 2005, BC Hydro has conducted several internal and external reviews of energy procurement practices and received input from a number of stakeholders in the process.[2] BC Hydro also recently completed the Clean Power Call, which was initiated in 2008. The Clean Power Call resulted in the selection of 27 projects for contract awards totaling 3,300 GWh/year. Other Energy Calls either completed or underway include the following:

1. F2006 Open Call for Power CFT – issued on December 8, 2005
2. Bioenergy Call for Power – Phase 1 RFP – issued on February 6, 2008
3. Standing Offer Program – launched April 11, 2008
4. Clean Power Call RFP – issued June 11, 2008
5. Haida Gwai RFP – Draft issued November 6, 2008
6. Integrated Power Offer – launched Summer 2009

[2] These assessments include: (1) Sage Report on IPP Procurement Process (January 2008); (2) Deloitte Report on BC Hydro Clean Power and Bioenergy Calls (August 2008); (3) IPPBC Submission to Green Energy Advisory Task Force (December 2009); and (4) Green Energy Advisory Task Force Report (April 2010).

7. Community-based Biomass Power Call RFQ – issued April 7, 2010
8. Bioenergy Phase 2 Call RFP – issued May 31, 2010

During that period, BC Hydro's energy procurement process has evolved to reflect lessons learned from previously initiated processes.[3] BC Hydro has indicated that it has over 110 active IPP contracts in its portfolio from a range of project developers that equal 15-20% of BC Hydro's total power supply.

One of the major issues identified by a range of stakeholders with regard to the implementation and execution of Calls undertaken by BC Hydro is the resulting high attrition rate of projects that have been awarded contracts. Stakeholders have identified a number of reasons for the attrition rates in British Columbia in response to the survey questions and interviews conducted by Merrimack Energy. Some of the reasons given by stakeholders include:

- The award of contracts to inexperienced and under-funded developers;
- Over-emphasis on price in combination with the goal of suppliers to "secure a contract";
- Under emphasis on project maturity and viability;
- Difficulties bidders have matching resource data to pricing constraints in the EPA. Attrition is a direct result of developers not pricing in the risk built into BC Hydro's contract terms;
- Political interference or reversal of policy makes it difficult to raise investment capital in an uncertain political environment;
- Calls for power are irregular, making it difficult for developers to stay in the game long enough to plan for project development.

While Merrimack Energy has not confirmed the reasons provided by stakeholders, high attrition rates for renewable resources have been common in other jurisdictions. For example, a study by KEMA, Inc. for the California Energy Commission[4] concluded that failure rates of 50% or greater for renewable energy projects in North America are supported by historical experience. Furthermore, it may be difficult to correlate attrition rates to any specific events or procedures.[5] Nevertheless, the feedback provided by stakeholders provides useful insight into some of the potential reasons for attrition rates in this industry.

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[3] As will be noted in this report, some of the comments received reflect supplier, First Nations and other stakeholder critique of previous calls such as the Clean Power Call. However, recent Calls, such as the Bioenergy Phase 2 Call, reflect improvement in the procurement process. In such cases, the report will identify those specific areas where revisions to the procurement process already reflect suggested changes by respondents to the survey conducted by Merrimack Energy or stakeholder interviews.

[4] Building a "Margin of Safety" into Renewable Energy Procurements: A Review of Experience with Contract Failure, January 2006.

[5] For example, the financial crisis which started in 2008 may have been a major reason why projects failed due to inability to secure financing.

C. Legislation and the Role of Government

BC Hydro operates with a clearly articulated sense of obligation to meet all expectations of the Crown, its sole shareholder.[6] The expectations of its sole shareholder are set forth formally in the Shareholder's Letter of Expectations which the Province and BC Hydro review annually and update as required. As described in the 2010 BC Hydro Annual Report (at pages 117-119), the Shareholder's expectations include:

- "BC Hydro shall conduct its operations and financial activities in a manner consistent with the legislative, regulatory and policy framework established by the Shareholder; and . . . .
- BC Hydro shall aggressively pursue all actions necessary to implement the objectives of the BC Energy Plan; continue to provide Government with a monthly progress report on key initiatives and as well a summary of annual progress on environmental leadership, innovation, energy conservation and efficiency, and energy security and self-sufficiency in BC Hydro's Annual Report to the Shareholder."

Ownership by the Crown sets BC Hydro apart from most similar US utilities which are privately owned. Privately owned utilities must observe in all respects applicable legislation and the orders of regulatory agencies empowered by legislation to regulate their operations through orders and regulations promulgated within the scope of the agencies' statutory authority. However, private utilities are less directly influenced by general governmental policies which are not specifically authorized by enabling legislation. In many cases, energy agencies in such jurisdictions operate with no greater influence over privately held utilities than other intervening stakeholders in regulatory adjudications.

In contrast, the Energy Ministry operates in this Province with the authority associated with the sole Shareholder of BC Hydro, turning what in other jurisdictions would be policy guidance into directives which BC Hydro cannot ignore. Evidence of the authority of the Ministry is shown in the above-cited provision of the Letter of Expectations calling for adherence to the directives in the BC Energy Plan.

In addition to the governmental control of the Ministry, the executive cabinet, formally referred to as the Lieutenant Governor in Council, also exercises considerable control over BC Hydro through its ability to issue directives to BCUC under the Utilities Commission Act (§3) and its control over the integrated resource plan, certificate proceedings and electricity purchase agreements of BC Hydro under the 2010 Clean Energy Act (§§3 and 4). This degree of control by a fourth arm of government, the cabinet of executive agency leaders, appears to set BC Hydro apart from both other

[6] No legal analysis of the statutory framework in which BC Hydro operates has been or could be performed by Merrimack Energy. Members of the bar of the Province must be relied upon for such an analysis. Nonetheless, Merrimack has included here assessments regarding that framework which are set forth in public documents reviewed by Merrimack Energy. The positions stated in these public documents are those of the authors.

publically-owned Canadian utilities and other public and private North American utilities which are predominately controlled by the legislature, a utilities commission with regulatory powers and to a lesser extent, by an energy ministry providing policy guidance.

This legislative, regulatory and policy framework creates constraints on BC Hydro's procurement activities which have been significant in recent years. While some stakeholders and First Nations may view those constraints as positive influences and others may view the same constraints as negative, Merrimack Energy has no role in this report judging governmental policy. However, the effects of the governmental framework on BC Hydro's procurement choices will be noted in this report as they are encountered.

In its 2010 Annual Report (at pages 120-121), BC Hydro reviewed the legislation and governmental expectations to which it is subject. Foremost in this regard is the recent enactment of the 2010 Clean Energy Act (CEA). The CEA establishes a long-term vision for British Columbia to become a clean energy powerhouse.

> "The Act sets the foundation for a new future of electricity self-sufficiency, job creation and reduced greenhouse gas emissions, powered by unprecedented investments in clean, renewable energy across the province. The Act builds upon British Columbia's unique heritage advantages and wealth of clean, renewable energy resources. The Act's priority areas include (2010 Annual Report at page 120):
>
> - Ensuring electricity self-sufficiency at competitive rates;
> - Harnessing BC's clear power potential to create jobs in every region; and
> - Strengthening environmental stewardship and reducing greenhouse gas emissions."

The CEA formally lists the energy objectives of the Province (§2); requires BC Hydro to submit, and the Lieutenant Governor in Council to review and approve, an integrated resource plan (IRP) (§§3 and 4); and pre-approves seven specific elements of BC Hydro's IRP, including Site C, the Bio-energy Phase 2 Call, the Clean Power Call of 2008, and the Standing Offer Program described in §15 and the Feed-in Tariff Program described in §16 of the CEA.

With its enactment, the CEA settles for the time the issue of the allocation of future resource needs between BC Hydro and the private sector and the issue of adding more green resources to the system even if they represent diminishing returns to an already green system. This allocation is consistent with energy directives in British Columbia for most of this decade. As early as the 2002 BC Energy Plan, it was clear that governmental directives were allocating incremental supply between the IPP industry and BC Hydro in a certain fashion described as follows:

> "Policy Action #13 (new): The private sector will develop new electricity generation, with BC Hydro restricted to improvements at existing plants."
> 2002 BC Energy Plan at page 30.

The text supporting this action item addressed the relative strengths of both parties, commenting on BC Hydro as follows: "BC Hydro's relative strengths lie in the operation of large-scale hydroelectric generation. . . . [a]ny new BC Hydro hydroelectric facility, such as Peace Site C, must be brought to Cabinet for approval before being considered by the Utilities Commission as a source of supply." The CEA can be seen as the evolution of the earlier allocation of resources which was anticipated as early as 2002.

Other recent legislation includes the 2008 Greenhouse Gas Reductions (Cap and Trade) Act, establishing a cap and trade system of emission regulation; amendments to the emissions standards of the former act setting into law the BC Energy Plan's zero net emissions requirement; 2008 amendments to the Utilities Commission Act, aligning the act with the BC Energy Plan's objectives; the 2008 Carbon Tax Act, encouraging the reduction in use of fossil fuels; and the 2007 Greenhouse Gas Reduction Targets Act.

Furthermore, the 2007 BC Energy Plan, following in the path of the 2002 BC Energy Plan, continues to exert influence over the procurement activities of BC Hydro, limiting its role and confirming the role of private suppliers in future procurements and establishing fundamental goals for BC Hydro.

> "The plan sets a goal for BC Hydro to acquire 50 per cent[7] of incremental resource needs through energy conservation and efficiency by 2020, while at the same time requiring:
>
> - All new electricity projects developed in BC will have zero net greenhouse gas emissions;
> - Existing thermal generation power plants will reach zero net greenhouse gas emissions by 2016;
> - There will be zero greenhouse gas emissions from coal-fired electricity generation;
> - Clean or renewable electricity generation will continue to account for at least 90 per cent of total provincial generation, placing the province among the top jurisdiction in the world; and
> - The province will be electricity self-sufficient by 2016."
>
> 2010 Annual Report at page 121.

Finally, in late 2009 key leaders in electricity and energy development from across British Columbia and Canada participated in the Green Energy Advisory Task Force to provide recommendations and advice to Government. The Task Force consisted of four Advisory Task Force Groups, including Procurement and Regulatory Reform. As we will discuss later in this report, many of the comments and recommendations of the Task

[7] The CEA increased this per cent to 66 (§2(b)) and the target for clean or renewable energy to 93%.

Force regarding energy procurement were consistent with the comments submitted to Merrimack Energy by stakeholders interviewed or those that submitted responses to the survey.

In summary, BC Hydro, in designing its procurement activities, must meet broad and comprehensive energy directives originating from four sources, the legislature, the Lieutenant Governor in Council (the cabinet), its financial regulatory agency (the BCUC) and the BC Ministry of Energy These arms of government have been proactive in recent years and may continue to be so in the future. As policies may change, BC Hydro must be ready to react quickly.

Coming from four arms of government, the present directives create constraints on BC Hydro's procurement activities which are at least as significant as any set of constraints Merrimack Energy has seen in other jurisdictions where government direction commonly comes from only the legislature and the regulatory agency. Since these constraints must be observed, they effectively limit the ability of BC Hydro to accommodate many of the comments Merrimack Energy has received from stakeholders and First Nations in this procurement review. Where those comments are inconsistent with these governmental policies, BC Hydro is constrained to follow its policy directives.

D. Objectives of Assignment

As noted, Merrimack Energy has been commissioned by BC Hydro to provide an independent assessment of the energy procurement and contract management practices of BC Hydro, with particular emphasis on the interactions with energy suppliers. The objective of this evaluation is to (a) assess current procurement practices and identify areas for improvement, and (b) assess current interactions with energy suppliers and identify areas for future enhancement of the relationship with suppliers. This energy procurement practices review will address the following functional areas within the overall energy procurement function:

1. Energy demand and supply planning
2. Sourcing and procurement
3. Project interconnection
4. Evaluation and risk allocation
5. Contract management and payment administration

E. Characteristics of BC Hydro's Procurement Activities

As previously noted, BC Hydro has issued a number of power calls over the past 5-6 years. There are several common characteristics that we can gather with regard to the procurement process, including the following:

- BC Hydro has conducted or is in the process of conducting several energy procurement processes and has executed a large number of contracts via the energy procurement processes initiated;

- Many of BC Hydro's procurements have either been directed by the Government or are tied to explicit government policy (e.g. removal of Burrard Thermal in BC Hydro's planning);

- BC Hydro's process provides significant opportunity for bidders to participate in the upfront activities associated with Call design;

- The process is focused on price as a primary determinant of project success, although BC Hydro does employ a project team with specific area skill sets to review bids from a project viability basis as well;.

- The success rates of projects that have received contracts has been somewhat low;

- While stakeholders have raised several issues regarding the risk allocation provisions contained in the EPA, there is a general consensus that the EPA is financeable;

- The IPP market in British Columbia contains a mix of small and large suppliers, however many of the traditional large IPPs present in US and other Canadian markets are not active in British Columbia;

- The stakeholder interest groups in BC have very different perspectives and interests that often conflict. In general, IPPs see a need and a large role for private sector development power in BC, whereas customer groups do not see a need for new supply or necessarily a large role for private sector development power in BC.

- BC Hydro's procurement processes have been evolving to reflect "lessons learned" and recent industry trends. For example, recent solicitations include more supplier involvement in the pre-proposal stage (i.e., opportunity for pre-proposal meetings between the supplier and BC Hydro) and post-proposal stage (i.e. opportunity for post-proposal bilateral meetings with select proponents before selecting preferred proponents), the application of a short listing process, and the identification of key criteria for evaluations.

II. Approach

As noted, the two key areas of focus of Merrimack Energy in undertaking this assignment are: (1) solicit input about BC Hydro's energy procurement process from suppliers, other stakeholders and First Nations for purposes of identifying options for improving the energy procurement process going forward and (2) assess the best practices from review and assessment of other utility procurements throughout North America as input into the development of best-in-class procurement practices for BC Hydro.

A. Overall Process

With regard to interaction with suppliers, other stakeholders, and First Nations, Merrimack Energy has undertaken a multi-stage process designed to solicit input and collect feedback and recommendations from stakeholders that will assist in improving BC Hydro's energy procurement process. The overall approach undertaken by Merrimack Energy includes the following activities:

1. Review previous CFT and RFP documents, reports on solicitations, consulting reports prepared by other consultants on the procurement process, and public policy documents;

2. Conduct face-to-face and phone interviews with stakeholders in the process as well as BC Hydro staff and management;

3. Conduct an independent survey of suppliers, other stakeholders and First Nations with a focus on the following issues:
    a. View of the parties with regard to the strengths and weaknesses of BC Hydro's energy procurement process;
    b. Suggestions for improving the process; and
    c. Rating of BC Hydro's interaction with suppliers at various stages of the procurement process.

    Merrimack Energy initially met with representatives from Clean Energy BC (the IPP industry association) in late September to discuss our suggested process for undertaking the assignment. Merrimack Energy prepared a draft survey and solicited input from Clean Energy BC and BC Hydro with regard to survey questions. The survey included information-gathering questions as well as several questions designed to rank specific aspects of BC Hydro's energy procurement processes. Additionally, Merrimack Energy sought feedback on the interaction between BC Hydro and suppliers on a range of activities during a solicitation process where interaction between the utility and suppliers generally occurs.

    A copy of the survey distributed by Merrimack Energy as well as the background memo explaining the survey that was sent to stakeholders is included in Appendix A. Respondents to the survey could choose to identify their organizations or remain anonymous. Merrimack Energy received fourteen responses to the survey.

In addition, Merrimack Energy conducted over 25 interviews encompassing a range of interested stakeholders and First Nations.

A list of the respondents to the survey as well as those who provided input via interviews or phone conversations is included in Appendix B.

4. Conduct a one-day workshop with interested stakeholders and First Nations to discuss consistent issues raised through the surveys and interviews as well as issues identified by Merrimack Energy regarding the procurement process relative to other jurisdictions. Merrimack Energy's approach was to identify 20-25 issues within the five major categories as raised by stakeholders and First Nations, along with potential solutions for addressing each issue. The initial part of the workshop focused on a broad discussion of each issue. After the discussion, the participants were separated into working groups to discuss the issues in more detail.

5. Conduct a detailed review of the procurement processes undertaken by similarly situated utilities[8] The utilities reviewed and evaluated include Hydro-Quebec, Ontario Power Authority, Southern California Edison, Arizona Public Service Company, PacifiCorp, and Puget Sound Energy. Exhibit 1 provides high level summary information for each utility including utility size, recent procurement processes, and jurisdictional requirements for competitive solicitations.

Exhibit 1 Summary of Sample Utilities

Utility	Size of Utility	Recent Solicitations	Jurisdictional Requirements
Hydro Quebec	Hydro Quebec's annual energy requirements based on recent data is 180,900 GWh with a peak demand of 36,625 MW. Hydro Quebec has over 42,000 MW of capacity, with over 90% hydro.	Hydro Quebec is completing a Call for Tenders for Wind Generated Electricity for two blocks of 250 MW each for Aboriginal projects and community projects. Hydro Quebec also completed a Power Purchase Program for Small Hydro Generating stations of 50 MW or less. The program involves the acquisition of a block of energy in Quebec from new aboriginal or local community hydroelectric projects for a total installed capacity of 150 MW.	Government policy in Quebec influences the type of solicitation and select evaluation criteria and weightings for each solicitation. Hydro Quebec's procurement process and the steps involved are based on a set of Procedures and Code of Conduct which is posted on the website. Hydro Quebec generally undertakes targeted solicitations.
Ontario Power Authority	Peak demand in Ontario is about 24,000 MW. Total	OPA initiated a Feed-in Tariff (FIT) program in 2009, which has been the primary source of	OPA/Government in Ontario has a major role in power procurement activities. OPA

[8] The list of utilities reviewed was developed based on the types of solicitations undertaken by the sample list of utilities, consistent regulatory and policy environments, focus on clean energy solicitations, and market structure.

(OPA)	existing generating capacity is 32,115 MW. Nuclear represents 32% of capacity and coal 18%. 3,300 MW of conceptual renewable resources are expected on line by 2019.	procurement recently. Contracts for FIT program projects totaling 2,000 MW were executed.	issues RFPs and executes contracts.
Arizona Public Service Company (APS)	APS has a peak demand of 7,218 MW; generation capacity of 6,288 MW and annual sales of 32,335 GWh.	In 2010, APS issued three major RFPs for renewable power supplies and several solicitations targeted to specific customer segments or areas of the service area. The major procurements include: • RFP for photovoltaic resources for a total of between 15-50 MW with the goal of 220,000 MWh. • RFP for 15-100 MW of wind resources in Arizona • Small Renewable Resource RFP	The issuance of RFPs in Arizona is driven by several factors: • Arizona has a RPS requirement • APS files an annual Renewable Implementation Plan which influences future RFPs. This is reviewed and approved by the Commission • APS has an Arizona Sun Program approved by the Commission which requires APS to invest $500 million for 100 MW of turnkey solar power projects in Arizona • RFPs in 2010 were the result of a Commission approved rate case settlement.
PacifiCorp	PacifiCorp system peak (7 states – east and west part of the system) is 11,406 MW; System generation capacity is 12,500 MW; annual energy requirements are 62,477 GWh.	Over the past few years PacifiCorp has undertaken an All Source RFP for 1,500 MW of resources, most of which are expected to be conventional generation resources. PacifiCorp has also issued RFPs for renewable resources over the past few years for a total of over 500 MW of nameplate capacity. Given its location, the predominant renewable resource is wind.	Utah has formal bidding rules which specify how the IRP and competitive procurement process is to be undertaken. Oregon has bidding guidelines which describe the requirements of the bidding process. The general process is that for renewable resources, Oregon takes a lead role but for conventional resource RFPs the Utah Commission has stricter requirements.
Southern	SCE system peak	SCE, like other California utilities,	California has a strict RPS

California Edison (SCE)	demand is 22,112 MW and annual energy requirements are 91,717 GWh; SCE has generating capacity of 9,820 MW but contracts for most of its energy requirements.	issues annual RFPs or RFOs for renewable energy resources to meet RPS requirements. SCE has also issued RFOs for Solar PV (rooftop and ground-mounted systems) resources as part of a five year 250 MW program and a Renewable Standard Offer RFP for renewable resources under 20 MW. SCE has a Feed-in Tariff program (called CREST) and has also issued regular RFPs for gas commodity resources and all source conventional generation resources.	requirement. In addition, although California has no formal bidding rules, procurement requirements have evolved over time through Commission Resolutions and Decisions. Recently, the Commission developed a Project Viability Calculator that utilities are required to utilize in the bid evaluation process. While the Commission has developed a number of procurement requirements, the utilities carry out the processes on their own.
Puget Sound Energy (PSE)	PSE peak demand is 4,987 MW and annual energy requirements are 22,000 GWh; PSE has 6,034 MW of generating capacity.	PSE generally issues all source RFPs based on the results of their IRP every two years. The all source RFP includes conventional and renewable resources. In addition, PSE has issued separate RFPs for energy efficiency resources.	Washington state has bidding rules which require utilities to issue RFPs for new resource requirements. Washington also has an RPS requirement. The timing and amount of resources sought are based on the results of the IRP.

The approach taken by Merrimack Energy involved a review of all or most of the following utility solicitation processes, RFP documents, model power contracts, and regulatory oversight requirements. Merrimack Energy also directly interviewed representatives from several utilities to enhance the information base. To develop a reasonably consistent base of information on each utility, Merrimack Energy developed a list of information requirements within each of the five categories on which to compile information and evaluate the utility procurement process.

The focus of the review of utility procurement processes is to assess the best practices and lessons learned from these utility processes, procurement practices and interactions with suppliers. The objective of this assessment is to compare and evaluate the characteristics of BC Hydro's procurement process to other utilities active in third-party procurement processes. Detailed summaries of the characteristics of the procurement processes for each of the selected utilities are included as Appendix C.

6. Based on the information received, conduct follow-up discussions with stakeholders and other utilities to confirm any important information and to supplement the information gathered.

III. Results

As previously noted, the surveys conducted as well as the interviews with stakeholders and First Nations were designed to solicit feedback and information on BC Hydro's procurement process with a focus on procurement and contracting practices and interaction with suppliers. In addition, we also solicited comments on the strengths and weaknesses of BC Hydro's procurement process, and information associated with the five procurement-related categories. To put the comments of respondents in perspective, background comments on the strengths and weaknesses of BC Hydro's procurement process and a high level summary of key general perspectives are first presented.

A. Strengths and Weaknesses of BC Hydro's Procurement Process

The surveys distributed to interested participants included a question about the strengths and weaknesses of BC Hydro's procurement processes. While there were a number of consistent responses, particularly with regard to weaknesses in the process, Exhibit 2 below provides a summary of the responses.

Exhibit 2: Strengths and Weaknesses of BC Hydro's Procurement Process

Strengths	Weaknesses
• BC Hydro's credit rating – reduces financial risk	• The process is not transparent enough
• Opportunity for long-term contracts up to 40 years in length	• The process does not provide enough information to allow companies to pursue projects with full information (which would then allow companies to allocate resources effectively)
• BC Hydro has run clear, fair and transparent Calls. BC Hydro is very good at running the mechanics of procurement steps once the Call rules are set, including process updates and posting Q&A's	• There is no regular timing for procurements which creates uncertainty and increases risk
• BC Hydro's record of fair and reasonable contract management and payment administration during the many years of IPP project operations is a strength	• BC Hydro has done a sub-optimal job of risk allocation in the Electricity Purchase Agreements. Contract terms are too complicated, which increases risk and bid price. Onerous terms are related to First Nations consultation, joint and several liability, 5 year ratchet and not allowing flow through of taxes.
• BC Hydro's post award reports have been well done and are	• BC Hydro does not seem to honor their own rules regarding contracts

informative	that have failed (e.g. Dokie Wind), and issuing contracts to developers that don't meet technical criteria
• The EPA is a financeable document	• The wind integration adjustment of $10/MWh is higher than almost all other North American jurisdictions and is based on a 20% wind penetration rate which is higher than actual experience in BC.
• BC Hydro does an excellent job of working effectively with suppliers and intervener groups to design the Calls.	• The evaluation criteria used by BC Hydro to determine which potential bidders meet the eligibility requirements for financial resources and experience are set too low. For larger project calls the eligibility criteria should be set higher than those for smaller projects. One option may be to set higher net worth requirements for larger projects.
• The initiative of BC Hydro in recent calls, such as the IPO, to meet with bidders to describe their projects before submission of the proposal was very useful.	• The practice BC Hydro uses to select winning bids based on the lowest adjusted price after having screened out projects that do not pass the eligibility stage results in a high attrition rate. The BC industry is still relatively immature and some developers that do not have any intention of constructing or operating the facility will submit low prices in order to obtain an EPA so that they can sell the EPA to another party.
	• Prior power calls have been structured to enable all sources to participate and allow all to compete on a level playing field. In theory this sounds reasonable and fair but in practice it is sub-optimal because two resources, hydro and wind dominate (biomass has their own power call). Power calls should be structured to reflect this reality and reflect the inherent characteristics of these technologies.

B. Summary of Stakeholder and First Nations Comments

Based on the interviews conducted by Merrimack Energy with stakeholders and First Nations as well as survey results, provided below is a listing of the major issues within each of the functional categories.

Before identifying the issues by functional area, a few higher level issues identified by respondents emerged throughout the responses, including the following:

1. The inherent conflict between BC Hydro in its role of supplier of public power and its role of acquiring private power contributes to a suspicion on the part of some respondents with regard to BC Hydro's interest in private power development. There is suspicion on the part of suppliers that BC Hydro is not committed to acquiring resources in competition with its own corporate mission;

2. The evaluation criteria do not effectively filter out weak projects/bidders and result in financially viable and stronger projects losing bids. The process is not transparent and is focused on price only. It is also not clear to stakeholders how the evaluation of bids is undertaken, particularly from a project viability perspective;

3. Although they have reservations, the bidders readily expressed appreciation and a positive viewpoint for the skills and outreach shown by BC Hydro in many aspects of the procurement process, including workshops, procurement design and mechanisms for interaction in the development of a procurement process, and the evident technical competence in contract administration;

4. The Electricity Purchase Agreements are financeable but also contain provisions that unduly shift risk to suppliers and result in higher cost projects;

5. There appears to be an inherent conflict between consumer groups and industry associations who prefer procurement processes to meet a defined need for power only in combination with procurement of the lowest cost resources for the benefit of customers and suppliers who prefer more frequent procurement processes to encourage the maturation of the industry;

6. There appears to be an inherent conflict between large and small developers with larger developers generally advocating for a more detailed project viability assessment as part of the evaluation process;

7. Bidders appear to be anxious to improve the process. They think changes can improve the success rate of projects and result in viable projects at a more reasonable price.

C. Discussion of Issues Raised by Stakeholders and First Nations by Functional Area

As illustrated in Appendix D, we received a number of comments in each of the functional areas. To reasonably address key areas, we have attempted to focus on five to six issues raised by stakeholders and First Nations within each functional area as a starting point for follow-up discussion of issues at the workshop. For purposes of addressing the objectives of the assignment, Merrimack Energy is adding a separate functional area to address interaction with stakeholders and First Nations rather than including these issues across the functional areas.

Energy Demand/Supply Planning

1. The results the Integrated Resource Plan ("IRP") should play a very important role in shaping BC Hydro's Energy Procurement, including:
    a. IRP should be consistent with government policy;
    b. The IRP and procurement activity should be linked, that is, the IRP should affect the timing and amount of Calls under all reasonable circumstances;
    c. The IRP should identify opportunities for procurement, provide consistent and regular timing for procurement, and identify the timing for the development of transmission infrastructure and interconnection to new resources that will meet the procurement plan;
    d. The IRP should provide guidance not only on the timing and volume of supply gaps but also the location and types of supply gaps;

2. The IRP should consider both domestic and foreign supply and demand. The IRP should include the outlook for exporting long-term firm electricity and how new generation for export markets affects the domestic market;

.

3. Political decision-making by the Legislature and Ministry of Energy is being second guessed by various stakeholders and First Nations, including ratepayer advocates who question the prices at which private supplies are being procured and suppliers who question whether the allocation of resources between BC Hydro (Site C, etc.) and IPPs in the BC Energy Plan and in the CEA is better than the competitive procurement of all resources with self-builds competing with IPPs. As noted above in the discussion of the role of government, this second-guessing by stakeholders and First Nations does not free BC Hydro of its duty to observe governmental directives.[9] Those directives presently include duties to

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[9] As early as the 2002 BC Energy Plan, it was clear that governmental directives were allocating incremental supply between the IPP industry and BC Hydro ("Policy Action #13 (new): The private sector will develop new electricity generation, with BC Hydro restricted to improvements at existing plants." (2002 BC Energy Plan at page 30). The text supporting this action item addressed the relative strengths of both parties, commenting on BC Hydro as follows: "BC Hydro's relative strengths lie in the operation of large-scale hydroelectric generation. . . . [a]ny new BC Hydro hydroelectric facility, such as Peace Site C, must be brought to Cabinet for approval before being considered by the Utilities Commission as a source of supply." Most recently, the allocation of resources was addressed in the 2010 Clean Energy Act, §7, confirming the same basic division of resources as first mentioned in the 2002 BC Energy Plan.

purchase additional green power and to develop its assigned assets, each in a cost-effective manner. In Merrimack Energy's view, meeting these duties may readily increase rates under current economic conditions notwithstanding the fact that BC Hydro could be performing its duties in a cost-effective manner;

4. Other stakeholders are comparing the regulatory adjudication of earlier Integrated Resource Plans at the BCUC to the Clean Energy Act's decision changing the regulatory review framework so that future IRPs will be reviewed administratively by submission to the Cabinet agencies. These stakeholders are also second-guessing this governmental decision and questioning whether their interests will be as well protected by administrative review as previously by regulatory adjudication;

5. Some stakeholders are willing to withhold judgment and have commented that the administrative review of an IRP must be implemented before its chances of succeeding can be evaluated. While the process provides ample opportunity for stakeholder input, questions remain whether it will be more effective than regulatory adjudication, which is resource-intensive and very time consuming, or less effective than regulatory adjudication, which is supported by formal fact-findings and evidentiary requirements;

6. For certain stakeholders, the basic question still remains whether the success of the IPP industry and the allocation of incremental needs to green IPPs should be carried out irrespective of costs and ratepayer benefits. In their mind, for a supply system of the nature of the BC Hydro system, it is still far from clear whether or not additional green resources from an infant industry represents diminishing returns at an undue cost. Although the Clean Energy Act and the earlier 2002 and 2007 BC Energy Plans have created for BC Hydro firm governmental directives to procure additional green resource and to achieve zero net greenhouse gas emissions, these advocates have not accepted current governmental direction as the final word.

Major Issues for Demand and Supply Planning

Several potentially contradictory issues emerged in our review of the comments made by respondents that were addressed in the workshop and set the stage for discussion. These include:

- While there appears to be wide-ranging support for a close link between IRP results and procurement activities, there are potential conflicts between the request for regular procurement activities and the need for new power supplies. We have found that in a number of other jurisdictions, the timing for procurement is based on the results of an IRP process (e.g. PacifiCorp (Utah and Oregon primarily), Portland General Electric, and Puget Sound Energy). If IRP results are closely linked to the issuance of Calls for Power, instead of regular procurements, the timing of power needs would drive the timing of power calls. If a need does not exist in sufficient quantity, regular procurements would be wasteful or impractical for the small quantities procured;

- Should there be a process to assess whether large generation projects generally undertaken by BC Hydro (i.e. Site C) should be subject to a competitive process or whether there would be a mechanism to seek a waiver from a procurement process before moving forward? In short, does the Clean Energy Act settle all questions about a Site C type project to the satisfaction of the stakeholders?

- What role should transmission planning have in the IRP process? Should transmission planning be the subject of an IRP or a separate process (e.g. California has initiated a separate process to identify transmission projects as a means of encouraging location-specific renewable development such as the Tehachapi area and the Imperial Valley transmission project)?;

- The role of the export market is fraught with uncertainty, long-lead time decisions, competition from other resources in the US and the current uncertain regulatory environment in states such as California. What is the preferred path forward and are there any models to use as a guide? In withdrawing any ratepayer financial support for the development of the export market, has the Clean Energy Act doomed the market to likely failure?

- Should the key input assumptions and methodologies used to develop the IRP process also serve as inputs and methodologies for undertaking the procurement process to ensure consistency of results?

- Should the IRP process be the proper vehicle to analyze important inputs for the procurement process such as integration costs, loss factors, transmission cost adders, etc.?

- Should the IRP process focus on planning for the entire BC Hydro system or should planning be regional or area based?

Sourcing and Procurement

Responses of stakeholders and First Nations in this category reflected the most diverse set of issues. In a number of cases, however, multiple respondents identified the same issues as being important. Thus, Merrimack Energy has attempted to identify the most frequently commented upon issues as well as those that, in Merrimack Energy's opinion, may have the most impact on assessment of BC Hydro's energy procurement process. The key issues are identified and discussed below.

1. For the most part**,** respondents described BC Hydro's current procurement approach as large, province-wide, and open to all renewable technologies provided they meet the clean energy guidelines published by the Province. Several respondents indicated that procurement activities may benefit from processes that are targeted (technology/region/product specific), smaller, but more frequent

a. Resources of different sizes should have separate procurements
b. Procurement for larger projects should be as flexible as possible
c. Different resources have different characteristics and should be procured separately;

2. BC Hydro's procurement process is not a very transparent process because it is not clear how BC Hydro evaluates the bids received. BC Hydro needs to be clearer with regard to identifying the criteria applied in the evaluation process and the method for selecting resources for contract negotiations. In this way, the bidder would know what it must do to compete. The level of frustration that low quality projects are selected is high, as expressed by the larger suppliers that provided input;

3. Price is the primary driver of bid selection, not project viability. Several suppliers claimed that neophyte bidders drive larger, more realistic bidders out of the market by bidding unrealistically low prices to get a contract. Several bidders also stated that BC Hydro's evaluation methodology focuses on the lowest price and does not give adequate weight to the viability of the bidder;

4. The Request for Proposals ("RFP") process is preferable to the Call for Tenders ("CFT") process. CFTs are rigid with no room for negotiations. Also, the time to close is too long and expensive which increases bid prices unnecessarily. An RFP process in general is a better form of procurement;

5. Several of the components of the bid evaluation methodology need to be reassessed including:

a. Wind integration costs
b. The calculation of losses
c. Pricing methodology which forces sellers to offer much higher prices for seasonal firm power;

6. Uncertainty associated with the time required to complete a solicitation process is troublesome for bidders. Suppliers were not happy with modifications that took place during or after the procurement process, such as the renegotiation of the Dokie Wind agreement after its execution.[10] Once a process is initiated there should be no modifications and BC Hydro should do what it can to maintain its schedule;

7. Some suppliers thought that the information contained in the solicitation documents is adequate to submit an effective proposal, but this view was not universal.

[10] The suppliers making this comment were aware that the renegotiation followed the bankruptcy of the original supplier and can be seen as implicitly criticizing bankruptcy as a valid basis for changing the procurement process.

Major Issues for Sourcing and Procurement

a. Targeted Solicitations (Project Type and Size)

Several stakeholders advocated more targeted procurement processes as opposed to larger open calls.[11] In addition, several respondents indicated they preferred a process that differentiates between larger and smaller projects. In that regard, there are a number of approaches undertaken by utilities.

A number of utilities base their procurement process on targeted solicitations based on resource type or size. For example, Hydro-Quebec's solicitations for renewable resources are all targeted solicitations for specific types of resources (e.g. wind-only, biomass, hydro, etc.). Other utilities distinguish between renewable and conventional resources but generally allow multiple renewable resource options to compete. One of the trends we have noticed in the electric market recently is the issuance of RFPs targeted to smaller renewable projects for specific applications. For example, Arizona Public Service Company (APS) has issued RFPs for distributed resources, small scale renewable resources, wind-only resources, small scale solar photovoltaics and even some solicitations at specific customer sites.

The California utilities, such as Southern California Edison Company (SCE), have issued RFPs or Request for Offers (RFO) for roof-top solar installations and a Renewable Standard Contract solicitation for small-scale renewable resources (under 20 MW) using primarily a standard offer contract. For the small scale RFOs, price is the primary determinant of resource selection once a bidder meets the general eligibility or threshold criteria specified.

The Ontario Power Authority (OPA) has issued solicitations for specific areas within the province as well as specific types of resources such as Demand Response and renewable resources. The RFPs issued are based on integrated power system planning initiatives undertaken by OPA in conjunction with the Ministry of Energy and the Independent Electricity System Operator.

Such targeted solicitations facilitate the bid evaluation process by allowing for evaluation of similar resources. These resources will generally have similar generation profiles and project structures and can be evaluated using more simplistic quantitative evaluation methodologies, such levelized cost analysis, as is the case with the SCE processes noted above. In addition, these solicitations are usually undertaken by utilities that conduct multiple solicitations over a short period of time. For example, APS has issued a number of very small solicitations for specific resources over the past few years based on its annual Renewable Energy Standard Implementation Plan and settlement agreements approved by the Arizona Commerce Commission.

[11] A few respondents indicated that calls should be larger in nature and should allow all resources to compete, including conventional generation, to ensure the lowest cost resources are selected.

Other utilities still rely on larger all source type RFPs when soliciting for renewable resources. Utilities such as Portland General, Puget Sound Energy, and PacifiCorp issue fewer solicitations that are broader in nature and may be based on the IRP results or Renewable Portfolio Standard ("RPS") requirements.

There are several issues to consider in identifying the best approach for BC Hydro. While targeted solicitations facilitate evaluation and contracting, in utility jurisdictions with a limited need for power and multiple competitive resource options, deciding on the resource allocation question is an important and often controversial decision. For example, when limited product is required, should a wind-only, hydro-only or biomass-only RFP be issued first? In British Columbia this issue may have to be linked to both the need for power and construction of transmission facilities if such facilities are needed to unlock the particular resource.

Several of BC Hydro's recent procurements are consistent with the targeted, smaller procurement approach used by both APS and SCE and are quite different from the larger procurement processes initially undertaken by BC Hydro.

b. Transparency of the Solicitation Process

Several respondents mentioned lack of transparency as a weakness of BC Hydro's procurement process but focused on lack of transparency with regard to the evaluation criteria and evaluation process as the primary examples. Merrimack Energy believes issues about transparency address both a macro as well as micro perspective.

From a more macro perspective, many jurisdictions have either adopted formal competitive bidding rules vetted through adjudicated regulatory or legislative processes (i.e. Utah, California, Washington, Arizona) or have developed bidding protocols, procedures, or guidelines that define how a procurement process would generally be undertaken (i.e. Hydro-Quebec and Oregon). For example, Hydro-Quebec Distribution developed bidding procedures prior to undertaking its first Call for Tenders in 2002. The procedures are posted on Hydro-Quebec's website along with a Code of Conduct that defines the requirements that internal and external resources must meet. Hydro-Quebec's bidding procedures is a seven page document that defines the steps in the process. BC has not adopted such high level guidelines for undertaking a procurement process and therefore suppliers and other stakeholders may be uncertain about the process as it is developing.

From a micro perspective, one of the primary considerations associated with transparency is a clear identification how bids will be evaluated, ranked and scored. Bidders generally want to know how they can effectively compete, including the criteria of importance to the buyer. One option for increasing transparency is to develop a point system or ranking system for the evaluation and identify at least the higher level evaluation categories and weights. Such an approach has taken several forms in recent solicitations, ranging from a utility identifying the weights for all major and sub-criteria (e.g. Hydro-Quebec, SCE and other California utilities, PacifiCorp), to identification of weights or rankings based on major criteria only (e.g. Ontario Power Authority and Hawaiian Electric), or identification of only general criteria with no weights identified (e.g. Arizona Public Service Company and Puget Sound Energy). As the review of other utility processes indicates, there is no clear cut approach used consistently in the industry.

Debate on the options and merits of each option should be undertaken by BC Hydro in conjunction with input from stakeholders and First Nations. The issues to be considered and balanced would include potential improvements made to bids based on clearer evaluation criteria and the relative need/desire for the utility to maintain commercial discretion in selecting bids.

c. Evaluation Methodology

Suppliers raised concern that price is the primary or perhaps only criteria used by BC Hydro to evaluate and select bids.[12] While BC Hydro has identified non-price and risk criteria of importance in the evaluation process, the apparent subjective nature of these criteria, the multi-facet stages and results of the evaluation process may be leading some stakeholders to conclude that price is the only criteria in bid selection.[13]

Utilities in other jurisdictions employ a range of approaches for conducting the evaluation of bids for larger more detailed procurement processes (such as the Clean Power Call) which may be simpler and more direct including the following:

1. Multi-stage evaluation process comprised of (1) threshold criteria to ensure the proposal meets certain minimum requirements to compete; (2) price and non-price screen to select a short list; and (3) detailed price evaluation to select the final projects;

2. Pre-Qualification process whereby bids have to meet certain minimum requirements to qualify. The process from there can be consistent with steps 2 and 3 above but the bidders may have to meet rigid hurdles to compete;

3. Indicative bid/final bid evaluation whereby the bidder submits an indicative bid only in the first stage and if accepted for stage 2 is then required to submit a firm price. In some cases, the allowed increase in price from indicative bid to final bid is limited to a specific percentage.

The use of rigid or lenient threshold criteria (i.e. demonstration of site control, experience in developing similar projects, demonstration of financial strength, etc.) generally

[12] The suppliers seemed to be focusing on the Clean Power Call as the example for raising this issue. While larger calls may include a more detailed evaluation process, targeted or smaller calls may not require such a detailed process. For example, Southern California Edison applies a more detailed evaluation process for its annual Renewable RFP but simpler, price-driven processes for smaller scale targeted solicitations such as the Renewable Standard Contract program and the Solar PV program solicitations.

[13] BC Hydro in its report on the Clean Power Call identifies a multi-stage process, which includes eligibility and conformity review, Quantitative and Risk assessment, initial evaluation and selection for post-proposal discussions, post proposal discussions, final evaluation, and EPA approval and award.

depends on the maturity of the market. If a competitive market is in its infancy stages, a buyer may want to use lenient threshold criteria to encourage more suppliers but more detailed non-price criteria to encourage the supplier to reach a certain minimum level of project development. On the other hand, if the market is fairly mature, more stringent threshold criteria are sometimes used as a mechanism of ensuring mature, well-developed projects are competing.

As an example, Hydro Quebec's Bid Procedures identify the multi-step process as the process to be followed by Hydro-Quebec. While this process is identified in the Bid Procedure, the specific criteria are not specifically identified and may vary from one solicitation to another.

It is also typical that the weights or rankings are used to conduct an initial screen to select a short-list. The final evaluation and selection is generally based largely on price, with non-price criteria used as a tie-breaker or to identify risk factors or fatal flaws. For example, typical weights are 60% price and 40% non-price, with the non-price percentage further disaggregated into a number of categories for evaluation purposes. Thus, the intent is that the best price and most viable bids will be selected for the short-list and from there price would generally be the primary determinant, with non-price or risk factors used as tie-breakers.

Of course, one of challenges is to determine the weights for price and non-price categories as well as the weights for each higher level non-price category and sub-categories. This process can be quite lengthy and challenging.

Also, the implementation of such a potentially subjective evaluation system can be the subject of controversy if suppliers feel they were not fairly evaluated. In response, utilities either attempt to make the non-price criteria as objective as possible (e.g. Hydro-Quebec) or retain an Independent Evaluator or independent consultant to ensure the evaluation and scoring is done fairly and objectively.

The issue of the appropriate methodology was addressed during the workshop and many stakeholders and First Nations supported the indicative bid/final bid evaluation process based on allowing suppliers who make the short list the opportunity to further refine their projects, including updating prices, with the additional time allotted between initial and final bids. Also discussed was the opportunity to use the time between submission of the indicative bid and final bid to undertake interconnection studies and develop more accurate pricing for their final proposal.

d. Other Issues

Several other issues were also discussed at the workshop related to sourcing and procurement issues. These included:

- A view by stakeholders that if bilateral contracts are considered, they would have to meet certain standards such as ensuring the pricing is consistent with other resource costs such as prices from recent solicitations along with the same contract terms. While it is our understanding that BC Hydro currently relies upon recent prices as a benchmark for bilateral contract pricing, it may be advisable to develop more transparent standards to guide bilateral negotiations;

- Although stakeholders supported using Request for Proposals processes as the default procurement mechanism, there was recognition during the discussions that it may be more appropriate for certain procurements to utilize other processes such as Call for Tenders or Request for Offers. Utilities such as Southern California Edison and OPA use different mechanisms based on the type of procurement implemented;

- While there were several comments about the wind integration charge used by BC Hydro in the Clean Power Call as well as the impact of losses on project evaluation in the surveys and interviews, there was little discussion during the workshop. As discussed, it is our understanding that BC Hydro is conducting an assessment of the wind integration charge as part of the IRP process, which is generally the appropriate vehicle used by other utilities to address inputs and assumptions for the IRP and RFP processes.

Project Interconnection

The experience of Merrimack Energy as Independent Evaluator in a number of procurement processes throughout the US and Canada is that transmission interconnection issues are the most challenging to resolve and have a major impact on project costs and ultimately, successful development of projects. The comments submitted by respondents through the survey and interviews mirror the types of comments raised throughout the industry.

Responses to the survey question about project interconnection were varied with regard to key topics but were generally consistent. Some of the major issues addressed include:

1. The entire interconnection process has to be revisited. Current efforts to integrate BCTC into BC Hydro and align the interconnection process are a step in the right direction and will go a long way to improve the process. Some specific comments included:
    - Turn around time to complete studies needs to be improved
    - BCTC's cost estimation process and assumptions used needs to be transparent and defensible;

2. The issue of concern to IPPs is the impact of the cost of interconnection and transmission on the bid evaluation and ranking process. Bidders have no idea what the impact will be on their competitive cost position:
    - Transmission and distribution will be stressed after the Clean Power Call meaning future expansions will add to costs and delay projects

- While BC Hydro absorbs the cost of transmission expansion, a higher actual cost than originally estimated increases the amount of security and the cost to the bidder without a commensurate increase in contract revenues;[14]

3. While BC Hydro has generally managed to build interconnection facilities on time for bidders to meet the Commercial Operation Date ("COD") it has been a challenge. Also delays in completing interconnection and transmission facilities increases the carrying costs to the supplier;

4. Interconnection request data forms may be onerous at the feasibility stage. BC Hydro should just ask for generic data at this stage. For example, BCTC wanted hard data on a specific generator/turbine. However, such data is not available from suppliers unless the supplier agrees to buy the equipment. This adds uncertainty to the process, particularly for small generators. The time at which the information is required is too early in the process for the bidder to identify its project-specific information;

As BCTC is integrated back into BC Hydro, it is anticipated that restructuring of the generator interconnection process needs to be considered. This may include a more integrated process as opposed to following FERC jurisdictional requirements.

Major Issues for Project Interconnection

- Is it possible for BC Hydro to identify areas of its transmission and distribution systems where the addition of new generation will trigger no or very limited interconnection issues, including transmission upgrades? These areas of the system are likely those areas where BC Hydro would want to encourage location of new resources;

- What are the primary issues associated with the interconnection process?
    - Cost risk associated with the unknown cost and therefore security requirements of bidders;
    - Time to complete interconnection facilities which delays the COD;
    - Cost responsibility for completing the studies and constructing the facilities;
    - Amount and type of information required of bidders to conduct the interconnection studies;
    - Amount and accuracy of information provided by BCTC in the various studies;

- Is it reasonable to conduct a study such as the California Transmission Ranking Cost Report ("TRCR"), which provides an estimate of the available

[14] While several suppliers raised this issue, it is our understanding based on review of the EPA and discussions with BC Hydro interconnection personnel that in fact, the cost of security for interconnections is a flow through under the EPA.

capacity at each major delivery point and the system transmission upgrade costs at the specific delivery point or area. While California utilities use the results for network upgrade costs and scope of facilities from interconnection studies to the extent they are available, for resources that do not have an existing interconnection to the electric system or a completed facility study the TRCR costs are used. PacifiCorp and OPA use similar approaches;

- Should there be a contract provision that allows for a free termination provision by the seller if interconnection and network upgrade costs exceed the estimated level plus a margin?

Discussions at the workshop by a BC Hydro interconnection group leader illustrated that BC Hydro is already initiating several revisions to the interconnection process. For example, it was noted that BC Hydro is assessing potential transmission capacity and costs at different points on the system, in a manner similar to the approach undertaken by PacifiCorp. Also, BC Hydro indicated it recognizes the issues associated with information requirements for specific turbines or technology when filing for the initial interconnection study even though the supplier has not committed to its generation technology at that time. BC Hydro is looking at ways to incorporate generic technology data at the initial interconnection stage to simplify the process.

A review of the approaches used by other utilities, some which are integrated utilities similar in approach to the direction followed by BC Hydro, as well as utilities which follow the FERC interconnection process, is provided below as examples of approaches which BC Hydro could consider.

Perhaps one model for BC Hydro as the BCTC is integrated back into BC Hydro is the Hydro-Quebec example. TransEnergie, the transmission business unit of Hydro-Quebec, is actively involved in the Call for Tenders process. In the first Step of the evaluation, TransEnergie conducts an assessment whether the proposal received can be interconnected based on the in-service date proposed. One unique aspect of Hydro Quebec’s process is that bidders generally have the opportunity to offer prices based on different in-service dates. TransEnergie’s analysis may result in rejection of one or two options, with perhaps only the latest in-service date proposed being the only eligible bid. In any case, the bidder will know the estimated time required to construct the interconnection facilities and will plan for the proposed in-service date accordingly. SCE has recently used a similar process to assess if an offer is capable of being interconnected within the time allotted to reach commercial operations under the renewable standard contract program.

Once the short-list of bids is selected, TransEnergie then conducts an assessment of the transmission costs necessary to interconnect portfolios or clusters of bids, if there are multiple projects in a same or similar location. The final selection is not based on the individual project and associated transmission cost but on the costs associated with a portfolio of projects, if applicable. See Appendix E for a more detailed description of the interconnection process undertaken by TransEnergie.

BC Hydro has made strides in the interconnection area as illustrated by the recent Bioenergy Phase 2 Call, e.g. use of a preliminary adjusted price spreadsheet and screening processes. As articulated by BC Hydro's interconnection group leader, it is expected that additional progress will be made as the interconnection function is integrated into BC Hydro.

Evaluation and Risk Allocation

This category primarily focuses on contract risk allocation issues as well as pricing issues in the contract, since pricing and contract risk allocation are woven throughout the process. In addition to addressing the contract and risk allocation issues raised by several suppliers, other stakeholders, and First Nations, Merrimack Energy has also prepared a detailed assessment of the provisions of the BC Hydro EPA which is used for large-scale projects and has made a comparison to other power purchase agreements used for comparable large-scale renewable resource procurement processes in other jurisdictions. This assessment is included as Appendix E. In general, BC Hydro's contract provisions, when considered as a whole, are notably more conservative than similar contract provisions for other comparable jurisdictions, thereby placing more development and operating risk on IPPs. Several of the major issues with regard to the EPA as raised by respondents include:

1. Suppliers feel some costs they currently must absorb are outside of their ability to control and should be passed through to BC Hydro with some tracking mechanism in the EPA. The flow-through costs most often mentioned are fibre costs, property taxes, water rights, and costs arising from changes in law. BC Hydro believes in most cases in the past that costs which are candidates for flow-through treatment are better managed by IPPs than by BC Hydro. However, BC Hydro recognizes in some cases, such as fibre costs and water rentals, that cost management is difficult for all involved.

   In general, BC Hydro emphasizes that governmental directives have limited its ability to respond to certain risk allocation issues raised by suppliers. For example, water rentals are controlled by government action and until recently, were set to follow changes in BC Hydro's rates, making BC Hydro reluctant to have a pass-through of water rental rates in its EPAs which compounded the effects of its rate changes. Since the government has very recently made water rental rates change with inflation,[15] this element of supplier costs has been brought within the reasonable control of suppliers who can incorporate an inflation-adjusted cost for water into their bids. For fibre costs, a governmental direction at the time the CEA was introduced on April 28, 2010,[16] prevents BC

[15] On December 2, 2010, the Province and BC Hydro announced that effective January, 2011, British Columbia's water rental rates will no longer be indexed to the rates of BC Hydro. In the future, water rental rates will be indexed to inflation.

[16] In a press release dated April 28, 2010, the same day the CEA was introduced, the Ministry of Energy announced that certain recommendations of the Green Energy Task Force, announced by then Premier

Hydro from passing fibre cost risk on to ratepayers. As discussed earlier in this report, Merrimack Energy recognizes that these governmental directives should be observed by BC Hydro.

With regard to other costs claimed to be outside the control of suppliers, Merrimack Energy notes that provisions which pass through costs for increased taxes and costs arising from changes in law are not common in industry contracts in other jurisdictions. As a result, Merrimack Energy is not making any recommendation with regard to cost pass-through issues.

2. The entire pricing structure for large scale projects was challenged by members of the IPP community as too strict, assigning more risk to the IPP suppliers than optimal to protect the interests of ratepayers. In fact, the claim made by the IPP community is that the assignment of more realistic and more flexible delivery risks to suppliers would result in lower bid prices that would more than offset the additional costs imposed on BC Hydro by the less strict delivery requirements. IPP suppliers expressed an interest in working collaboratively with BC Hydro in quantitative modeling which tests the impact of more flexible pricing rules against the impact of the stricter current EPA rules on the balance of costs and benefits to ratepayers represented by each approach.

3. Foremost among the key pricing issues was the firm delivery obligation for seasonally firm energy. In Merrimack Energy's experience with intermittent resources, firm delivery obligations are uncommon over short seasonal periods, particularly so when combined with financial penalties starting with the first MWh of under- or over-delivery in a season. Other utilities of varying sizes, which purchase intermittent renewable resources for their energy value and/or in satisfaction of renewable portfolio policies, most commonly, in Merrimack Energy's experience, set target energy delivery amounts based on an annual production target bid by the IPP. Common to all utility efforts is some requirement to acquire resources in a prudent, cost effective manner and implementing this requirement has generally meant that these utilities test for delivery performance against the target each year, or every two years against some multiple up to twice the annual target or alternatively, every year against the annual target but calculated on some multi-year rolling average.

4. In addition to the seasonal delivery requirements, liquidated damages (LDs) starting at the first MWh of under-delivery and large price reductions starting at the first MWh of over-delivery were criticized by IPPs. LDs were viewed as onerous and, although BC Hydro defended them as reasonably low at $5.00/MWh (or cover costs), IPPs complained that they were higher than actual damages. Since bid prices have generally exceeded the cost of cover to BC Hydro, this low damage amount is likely to exceed actual damages. However, BC Hydro points out that without this low penalty, there would be little, if any, disincentive to

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Campbell in November, 2009, were not being moved forward, including, "Transfer of all biomass fuel price risk to BC Hydro under biomass electricity purchase agreements."

bidders against setting unrealistically high target amounts for seasonally firm energy which amounts are then entitled to receive full price payments from BC Hydro. In Merrimack Energy's view, this could result in overpayment for renewable deliveries on which BC Hydro could place little reliance in planning its supply.

Certain other jurisdictions also have low minimum damages (such as $2.00/MWh or cover costs for Hydro Quebec), but use them in combination with different, more flexible testing procedures based on annual or multi-year testing periods and with different, more flexible pricing rules for delivered energy. In this regard, a three-year rolling average is used by Hydro Quebec to measure yearly performance against its annual target and its low liquidated damages amount does not apply to the first 5% of under-delivery against that annual target. Furthermore, over-deliveries to Hydro Quebec receive full price payments up to 120% of the annual target, which encourages lower, more realistic annual targets. In the United States, PG&E uses 160% of Contract Quantity over each consecutive two-year period for its target performance for non-wind renewables and the annual P-95 Value for its wind resources. Under-deliveries are less likely with these reduced targets and PG&E also allows the supplier another year to cure any under-delivery by achieving in the following year delivery of 90% of the annual target amount. In the absence of cure, a minimum penalty of $20/MWh is imposed from the first MWh of shortfall. Another Canadian jurisdiction (Ontario) has no minimum delivery requirement, and no liquidated damages, for under-delivery of renewable resources. Other utilities (such as PacifiCorp) test annual availability for wind resources and not actual energy delivery and rely solely on formulae for cover damages and not minimum liquidated damages.

The financial penalty which applies under the BC Hydro large-project EPA starting with the first MWh of over-delivery in each season is non-firm pricing. This is generally far below firm energy pricing but is defended by BC Hydro as market pricing. IPPs challenged the non-firm pricing as too low to carry actual project costs. In the view of the IPPs, the overall pricing structure has unfavorable incentives in each direction - - if firm nominations are set too high, liquidated damages are frequently paid and if too low, the seller loses necessary, firm price revenues. In Merrimack Energy's experience, utilities generally have more flexible pricing provisions which often allow firm pricing for over-deliveries up to a significant percentage above a target annual amount (120% is common, such as for Hydro Quebec and Hawaiian Electric).

In Merrimack Energy's overall assessment, it is the combination of the strict seasonal delivery requirements with the financial penalties immediately above and below the seasonal targets that may transfer more risk from BC Hydro to the suppliers than necessary to protect ratepayers.

5. The 5-year ratchet clause was attacked by IPPs as too harsh since it could force the contract seasonal firm energy amount down for five years to a dramatically lower level based on a small proportion of bad seasons occurring after the first anniversary of the COD. The new level each five year period would be based on the seasonal amount exceeded 80% of all of the similar seasons since the first anniversary. Over the term of the EPA, the levels would be set by the worst season when considering the first five years, the second-worst season when considering the first ten years, the third-worst season when considering the first fifteen years, the fourth-worst season when considering the first 20 years, and so forth. Since reductions increase the portion of delivered energy priced at the lower non-firm price, dramatic reductions could have dramatic negative effects on revenues. While other industry contracts have similar mechanisms to adjust delivery requirements and pricing terms for past under-performance, other adjustments are not focused on the worst evidence of seasonal under-performance over long periods of time. For example, Hydro Quebec reduces the delivery target to the amount that reasonably can be maintained based on historical performance back to the Commercial Operation Date. On the other hand, Hawaiian Electric does use the lowest three-year rolling average, but the adjustment is not triggered unless the average is less than 80% of the Annual Contract Energy.

6. In the view of Merrimack Energy, it would be useful for BC Hydro to complete a financial analysis, in collaboration with stakeholders and First Nations, to assess if more flexible contract provisions, which shift less risk to the supplier than the EPA provisions, achieve a better balance of costs and benefits to ratepayers. If the analysis does suggest a better balance will occur, BC Hydro would presumably then modify its contract provisions for better alignment with prevailing industry standards.

7. The EPA provisions dealing with First Nations' risk raise questions whether the risk is being managed completely and effectively. If prior to the second anniversary of COD BC Hydro is subject to actual or threatened legal proceedings or a court or regulatory decision regarding potential adverse impacts on aboriginal rights arising from the EPA or the project, then BC Hydro can delegate any consultation requirements to the Seller and can require the Seller to take measures to prevent, mitigate, compensate or otherwise accommodate the affected First Nations. However, if the Seller is unable to adequately consult with and/or accommodate the impacted First Nations without being exposed to commercially unreasonable costs or other obligations, having regard to all other financial benefits and burdens of the EPA to the Seller over the full term of the EPA, the Seller may terminate the EPA without liability to the Buyer. Termination of the EPA may be voided if the parties can work out an alternate solution such as an amendment of the EPA or if BC Hydro withdraws the delegation of these requirements to the Seller. Terminating the EPA before COD or within two years after the project has entered service appears to be an incomplete solution for both the Buyer and the Seller.

In the event that the EPA is terminated, the project developer will no longer receive a contracted revenue stream from BC Hydro. For BC Hydro, depending on the status of the legal proceedings and the project there may still be a legal requirement to address the First Nations consultation and accommodation deficiencies identified in the actual or threatened legal or regulatory proceeding.

Thus, when the parties cannot reach a satisfactory solution regarding the First Nations consultation and accommodation requirements, the EPA termination appears to be the sole post-COD remedy provided. Recognizing this possibility should bring renewed attention to resolving all First Nations questions during the procurement process or the contract milestone process. Resolution of First Nations issues appears to require early and effective management.

Contract Management and Payment Administration

The functional category where comments were most limited was in the contract management and payment administration. However, the responses from those who were able to opine on this area were very favorable overall. A sample of responses includes the following:

1. We are very pleased with contract management activities. BC Hydro has developed a spreadsheet to keep track of billings and meters. The process is very efficient and well done;

2. The contract management process has gone very well. The large excel spreadsheet developed by BC Hydro is complex but effective. BC Hydro has a good support team to deal with counterparties. Management of the contracts has been good;

3. Once the bidder gets through the procurement and interconnection processes with COD in place, the contract management and billing function works well.

Nevertheless, Merrimack Energy has communicated with other utilities that have executed and managed a number of contracts to assess whether there are other practices that may aid BC Hydro improve its contract management practices as more projects come on-line. Similar to BC Hydro, other utilities generally manage power contracts within the same group that is responsible for the contract negotiations. Other utilities have also developed their own software to track contracts through the project development process as well as the operations phase. APS, for example, adopted a critical path software package to track milestones in project development and to track performance once the project is on line. APS also indicated that its contract management group communicates frequently (at least monthly) with the counterparties for all contracts it has under development or in operations.

Interaction with Suppliers

Given the importance of this issue to BC Hydro and based on the responses provided to the survey, Merrimack Energy decided it would be useful to break-out this category into a separate category for purposes of this report. As illustrated in Exhibit 3, suppliers awarded BC Hydro fairly high marks for the interaction with suppliers in the RFP development stage of the process but lower marks once the RFP was issued and proposals were being developed and evaluated. For example, BC Hydro was lauded for the usefulness of the workshops as a valuable means for understanding the procurement process and its requirements. In addition, incorporation of feedback from suppliers in designing the RFP and EPA were viewed as responsive along with BC Hydro's responses to questions. For example, one respondent mentioned that the initiative of BC Hydro in the IPO to meet with bidders and allow bidders to describe their projects before bid submission was very helpful. We did not receive any comments complaining that BC Hydro did not consider the bidders comments in the RFP development phase of the process.

Exhibit 3: Summary of Responses – BC Hydro/Supplier Interaction

Areas of Interaction	Excellent or Very Responsive	Good or Generally Responsive	Average/Needs Improvement	Poor or Not Responsive	Not Applicable
1. **Development of CFT, RFP, or other Call Documents**					
• Comments on development of documents		4	3	1	
2. **Bidders Conferences, Workshops and Meetings**					
• Opportunity for questions	1	4	3		
• Quality of BC Hydro presentations	1	4	2	1	
• Interaction with Interconnection team	1	1	1	2	1
3. **Questions and Answers**					
• Quality of responses		2	4	1	
• Timeliness of posting responses to website		4	4		
• Level of direct contact with BC Hydro team		3	3	2	
4. **Preparation of Proposals**					
• Responses to questions		2	2	1	2
• Clarity and transparency of solicitation documents		4	2	1	1
• Quality of information provided to suppliers		4		2	1

5. **Bid Evaluation**					
• Follow-up clarification questions		1	1	3	2
• Time provided for clarification response		2		3	2
• Timeliness for completing evaluation			1	6	1
6. **Selection of Winning Bidders**					
• Timeliness of selection			1	7	
7. **Response to losing bidders**					
• Adequacy of feedback			1	2	4
8. **Contract Negotiations**					
• Interaction during negotiation process			2		5
• Time for completing contract negotiations					7
9. **Contract management**					
• Invoicing and payment process	1			1	5
• Interpretation of EPA clauses		1	2		4

The negative responses were associated with the interaction with suppliers after issuance of the RFP. Suppliers had a sense that BC Hydro was overly cautious in providing information to bidders for fear that some bidders may be treated unfairly or may not receive the same level of information as other bidders, thus jeopardizing the fairness of the process. In doing this, BC Hydro provided little guidance or assistance to suppliers to prepare their proposals. Some of the responses from stakeholders included the following:

- BC Hydro is open in how it will conduct the process prior to it commencing, but once the process is underway, it is not open;

- The Clean Power Call was not very transparent in how various value-added offers would be evaluated. Further, after the process is commenced, it is not transparent in how decisions are made even in the evaluation report;

- The workshops offered were very helpful in understanding the process and requirements;

- The initiative of BC Hydro in the IPO to meet with bidders to describe their projects before submission of the proposals was very useful;

- BC Hydro de-briefed the suppliers after the process was completed and provided reasonable information;

- Once the contract is signed, there is no dialogue about progression of the project;

- BC Hydro staff has been good in addressing specific problems faced by suppliers;

- One of the strengths of BC Hydro's procurement process is its ability to work effectively with suppliers and intervener groups to design the calls.

Utilities generally vary in their response to bidders throughout the solicitation process. In a number of processes we have found that, like BC Hydro, the interaction with bidders is greatest prior to proposal submission. Once proposals are submitted the interaction with bidders is more limited until a bid is accepted for contract negotiations. Also, in most cases the information provided by utilities to losing bidders is limited in scope and generally does not involve a detailed review of the evaluation of the bid on a point-by-point basis. Instead, feedback is generally limited to those areas where the proposal did not rank highly versus those areas where it did rank highly.

However, there are exceptions to the general approach followed primarily for larger procurements where bidders are more sophisticated and experienced. For example, Southern California Edison has conducted solicitations for smaller projects, such as their Solar PV program (roof-top projects and ground-mounted solar projects less than 10 MW) and the Renewable Standard Contract ("RSC") program (bids less than 20 MW). Merrimack Energy served as the Independent Evaluator ("IE") in both cases. In both these programs, the level of communications about specific projects between SCE's project team and the bidders was substantial. Instead of restricting communications to the website only, suppliers were allowed to send questions or comments to the specific mailbox established for the process and SCE staff responded "interactively" to questions as they came in. In fact, as IE we also received all questions and answers. As IE, there were occasions where we suggested that SCE provide the information provided to one bidder to all bidders instead.

A second example of interaction with bidders is the approach of the Ontario Power Authority to meet with registered bidders for one hour about one month prior to receipt of bids. The purpose of these meetings is to allow the bidders to ask questions about the RFP with regard to their specific projects. The Fairness Advisor is present at the meetings. In recent procurements (e.g. Bioenergy Phase 2 Call), BC Hydro has also followed a similar approach, offering to meet with bidders at least once before bids were due to discuss their projects.

A third example of interaction with bidders through the solicitation process is the approach used by PacifiCorp to ensure that PacifiCorp's evaluation team and the bidder are in total agreement how the bid should be interpreted prior to beginning the evaluation of bids.[17] In this case, PacifiCorp establishes a summary sheet of all the key project information submitted by the bidder based on its interpretation of the bid. The Company

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[17] PacifiCorp uses this approach for the conventional generation RFPs which require a more thorough understanding of the operating parameters for each proposal.

then submits the summary sheet to the bidder for review and revision. If there are any inconsistencies, PacifiCorp initiates a conference call with the bidders to ensure there is agreement about the proposal.

Another approach undertaken by utilities is to meet with short-listed bidders only after the initial evaluation and prior to undertaking the detailed evaluation. The purpose of these meetings is to assess whether the project or any elements have changed since the submission of proposals and to address any areas of the proposal where the utility has questions of the bidder. As IE, Merrimack Energy has found such meetings with short-listed bidders to be particularly valuable because the meetings generally provide a more in-depth discussion of the proposal via direct contact with bidders. Arizona Public Service Company has used this approach very effectively in its solicitation process, particularly since APS does not use a point ranking system but a system based primarily on price but including a detailed risk assessment of specific project categories.

A final approach used by utilities to effectively interact with stakeholders is the Procurement Review Group (PRG) process used in California. The PRG is an advisory group only. As previously noted, all California utilities are actively involved in procurement processes and all have a PRG which is involved in reviewing procurement activities including procurement design, evaluation and selection of proposals, and contract negotiations and advising the utility on these aspects of the procurement process. The PRG is comprised of non-bidding stakeholders who have a knowledge of and interest in the state energy markets.

For the Solar PV Program in California, the Commission requires that the utility hold a forum with bidders and other stakeholders after completion of a solicitation to discuss lessons learned with the objective of improving the process for the next solicitation. This is another example of interaction between the utility and bidders for purposes of improving the procurement process.

While there may be options to address the concern of stakeholders that BC Hydro does not undertake adequate interaction with suppliers after issuance of the RFP, it is noteworthy that BC Hydro has begun in recent procurements to interact with bidders after bid submission through the opportunity for face-to-face meetings.

D. Experiences of Utility Procurement Processes Relative to BC Hydro

In addition to assessing the comments and views of stakeholders and First Nations with regard to BC Hydro’s energy procurement process, Merrimack Energy also conducted an assessment of the approaches of other utility procurements in relation to BC Hydro’s process and procedures. The approaches of other utilities also served to influence our recommendations. A description of BC Hydro’s procurement activities and processes, the approach of other utilities and Merrimack Energy’s ranking of BC Hydro relative to industry practices is included in Exhibit 4.

Exhibit 4: Procurement Approach of BC Hydro Relative to Industry Practices

Procurement Component	BC Hydro Approach	Other Utility Practices	BC Hydro Rank and Comments
Energy Demand and Supply Planning			
1.Role of IRP	BC Hydro has not had a formal IRP process until the recent Clean Energy Act has mandated IRP. The Long-Term Acquisition Plans completed in 2005 and 2008 served as a basis for planning and procurement in the past. However, it does not appear if this process is as comprehensive as a formal IRP process.	Several utilities in the US rely on a formal IRP process as the basis for determining when to solicit for power, how much and what type of resources (PacifiCorp, APS, Puget Sound Energy); Others have relied upon a combination of government policy and supply plans to determine the basis for procurement (California, Ontario and Quebec)	BC Hydro rank – below average at this point. However, the implementation of the IRP with a close linkage between the IRP, government policy and procurement activities will bring BC Hydro to a position of consistency with other utilities and in line with or above best practices.
Sourcing and Procurement			
2. Transparency of the Procurement Process	There are no formal bidding rules, guidelines or procedures in BC. BC Hydro has developed procurement practices that have not been formally adopted.	In most states or provinces with active competitive procurement processes there are generally formal bidding rules or guidelines developed through a stakeholder process (i.e. Utah, Oregon, Washington, and California), in consultation with the regulatory Commission (Arizona), or developed by the utility (Hydro-Quebec).	BC Hydro rank – below average. The development of guidelines or procedures serves to improve transparency of the process for all stakeholders and sets the framework for conducting the procurement process so that all stakeholders are aware of the rules or guidelines in advance of preparing a bid.
3.Clarity of Procurement Documents	BC Hydro has significant experience in the development and implementation of procurement processes and has developed clear and concise solicitation documents.	Other utilities generally provide the same or similar information as provided by BC Hydro in their procurement documents. The one difference appears to be the level of detail associated with the evaluation criteria and evaluation process.	BC Hydro rank – Average. BC Hydro's procurement documents are generally clear and provide a substantial amount of information on which to base a proposal. Suppliers had no problem with the clarity of the procurement documents.
4.Types of Solicitation Processes and Mechanisms	BC Hydro has been launching a number of	Utility practices have varied from those that	BC Hydro rank – Above Average. The

	different procurement processes to reflect the specific target market for the solicitation such as the Clean Power Call, Bioenergy 1 and 2 Calls, Standing Offer Program and Feed-in Tariff. In addition, BC Hydro has used multiple procurement mechanisms to procure power such as RFPs, Call for Tenders, Feed-in tariff, and standard contracts.	issue a range of procurement mechanisms and processes based on the specific resources solicited (i.e. SCE, OPA and APS) to those that conduct infrequent all source type solicitations (i.e. PacifiCorp and Puget Sound Energy) using primarily an RFP process.	recent procurement processes undertaken by BC Hydro reflect an approach used by some of the more sophisticated utilities who actively rely on a variety of procurement mechanisms and processes to target specific types of resources and markets.
5.Interaction with Suppliers Prior to Receipt of Bids	BC Hydro interacts with suppliers on a number of levels prior to submission of bids. For example, bidders and other stakeholders have the opportunity to provide comments on the RFP and EPA documents; BC Hydro conducts workshops and conferences for bidders; there is an active Q&A process, and BC Hydro also offers the opportunity for bidders to meet with the company prior to bid submission.	The standard practice by utilities is to issue an RFP (that may or may not be approved by the public utility commission), hold a bidders conference to explain the RFP and solicitation process, and respond to questions via the company website. There is generally no direct interaction with individual bidders. In some cases, bidders and other stakeholders have the opportunity to comments on the draft RFP and contracts.	BC Hydro Rank – Above Average. BC Hydro interacts considerably with bidders prior to receipt of bids and to a greater degree than is the industry norm for procurement processes in other jurisdictions.
6.Interaction with Suppliers After Receipt of Bids	Until the recent Bioenergy 2 Call, it can be argued that there was little interaction with bidders once the proposals were received. The historical lack of engagement with bidders by BC Hydro has been exacerbated by the lengthy bid evaluation and selection process that has resulted from a number of factors.	Common practices in the industry have varied by utility and range from no involvement until a short list or final award group is selected (with the exception of clarification questions) to limited involvement with bidders prior to the initiation of contract negotiations. A number of utilities do hold follow-up meetings with short listed bidders or engage bidders through communications on solicitation status. A	BC Hydro Rank – Below Average. The below average ranking is based on previous practices of BC Hydro. However, recent practices appear to be moving in the direction of engaging bidders to a greater degree through the opportunity for meetings with select bidders during the selection process as implemented in the Bioenergy 2 Call.

		number of utilities also maintain a fixed schedule so bidders know when to expect a decision.	
Evaluation and Risk Allocation			
7.Evaluation Factors	BC Hydro identifies the factors it uses to evaluate and select bids in the reports prepared by BC Hydro for each procurement process. However, the specific evaluation factors are either not identified in the RFP or CFT documents. Furthermore, there have been questions on the magnitude of the factors included in the evaluation (e.g. integration costs, losses, etc.)	Integration costs are used by other utilities along with losses as evaluation factors in the selection of the preferred resources. While the level of integration costs used by BC Hydro may be higher than some utilities, the level of integration cost is not "out of the ballpark".	BC Hydro Rank – Average. BC Hydro has indicated that it is conducting an assessment of evaluation factors such as wind integration costs and losses as part of the IRP process.
8.Evaluation Process	BC Hydro relies upon a process based largely on price of the proposal along with other evaluation criteria. The evaluation criteria are identified in the RFP documents but there are generally no weights or indication how bids would be ranked within each category. Also, there has traditionally been no short listing process or identification how a bid would be selected for contract award. Although BC Hydro indicates that risk or non-price assessment will be part of the evaluation process, it is reasonable to conclude, as a number of suppliers have, that price has traditionally been the primary determinant for selecting a resource.	Most utility processes involve some combination of price and non-price or risk/project viability criteria and defined steps for reaching contract award. While the level of transparency of ranking at various stages of the process varies by utility, there is generally an indication how bidders will be evaluated throughout the procurement process. While price is generally a final selection determinant, most procurement processes include some form of risk or non-price assessment as a means of selecting a short list. The transparency of the process ranges from a utility identifying the	BC Hydro rank – Below Average. In Merrimack Energy's view, BC Hydro's traditional procurement processes have not provided a defined evaluation process or the stages of the evaluation that would be reasonably transparent to bidders. BC Hydro provides limited information on how bids will be evaluated and ranked at different stages of the process, including the basis for resource selection. Most utilities provide more information on the bid evaluation and selection process than BC Hydro.

		specific criteria for consideration to providing a scoring and ranking system to select a short list of bids.	
9.Timeliness of Completing the Solicitations	One of the issues raised by suppliers is that BC Hydro does not complete its procurement process on schedule which creates uncertainty for bidders and adds to project costs	Many utilities focus on completing the procurement process consistent with the proposed schedule to send a clear message to bidders for this and future solicitations that the utility will follow its schedule and process as stated to meet bidder expectations. While this is a common objective of many utilities, it is not uncommon for schedules to be revised or changed due to extenuating circumstances. Some utilities such as Hydro-Quebec and SCE are very focused on meeting proposed schedules while PacifiCorp has often revised their schedule for completion of the RFP.	BC Hydro Rank – Below Average – In Merrimack Energy's view one of the objectives of BC Hydro, the government and participants for future solicitations should be to do everything possible to meet schedule deadlines and manage unforeseen circumstances in the most appropriate manner. The goal should be to enter discipline in the process to send a clear signal to the market.
10.Contract Risk Allocation	BC Hydro has developed a detailed EPA that is viewed by sellers as being financeable. There are, however, a few issues that were identified by stakeholders and First Nations and addressed by Merrimack Energy that shift undue risk to suppliers and could lead to higher project cost.	Utilities have developed PPAs that contain many of the same provisions and risk sharing mechanisms as addressed in BC Hydro's contract. Merrimack Energy has presented summaries of several contracts in this report.	BC Hydro Rank – Merrimack Energy has assigned a two-part rank for the pricing and non-pricing provisions of the EPA. For pricing provisions, until a financial or economic analysis resolves doubts whether the present pricing algorithms serve consumers as well as other more standard provisions, our view is that on balance BC Hydro's contract would rank lower than industry average. This price rank is only

			slightly below average, however, since the outcome of the financial analysis is not yet known. With regard to non-price provisions, we balance the fact that the contract risk terms are very complex against the fact that the provisions are consistent with or less onerous than other industry contracts and that some degree of complexity is unavoidable in this type of industry agreement. As a result, for non-price provisions, the contract risk allocation is average or slightly above average.
Project Interconnection			
11.Interconnection Process	BC Hydro has implemented an interconnection process which includes a preliminary assessment of interconnection and system upgrade cost prior to submission of proposals and conducts system impact and facility studies after contract execution.	Interconnection problems are common to virtually every procurement process. The challenges with regard to interconnection are influenced by whether or not the utility is part of an ISO or includes the interconnection process within the integrated utility system.	BC Hydro Rank – Average. Despite the issues raised by suppliers about interconnection, BC Hydro has performed consistent with industry practices. We feel BC Hydro has an opportunity to improve this rank with the integration of BCTC back into BC Hydro and initiatives underway within the Interconnection group.
Contract Management and Payment Administration			
12.Contract Management	BC Hydro has developed an organized and detailed process to manage contracts including keeping track of billing and metering information. BC Hydro utilizes a detailed excel spreadsheet to manage and implement	Contract management is one area where utilities have their own unique methodologies and approaches for managing contracts. All utilities appear to have some form of software to monitor contract progress as well as track contract	BC Hydro Rank – Average. The average rating is based on the fact that there are no specific industry standards and utilities are still evolving their contract management and payment administration process. Contract management

	contracts.	milestones and payment requirements. Similar to other utilities, BC Hydro manages power contracts within the same group responsible for contract negotiations.	appears to be one area where utilities feel there are plenty of opportunities to improve their processes.

IV. Conclusions and Recommendations

Merrimack Energy has reviewed the documents and EPAs underlying recent BC Hydro solicitations, reports on the procurement process, and information surrounding the Clean Energy Act as well as soliciting input and comments from stakeholders and First Nations and conducting a review and assessment of procurement practices of other utilities in North America. Through this process we have found that recent procurement initiatives of BC Hydro are incorporating "lessons learned" from previous procurements and are moving BC Hydro's procurement process more inline with the procurement processes implemented by utilities that are recognized as leaders in the industry. However, despite the improvements made by BC Hydro to enhance their procurement process, including interaction with suppliers, Merrimack Energy has identified several potential areas for improvement. Fortunately, the timing for conducting this assessment and making improvements to the process is ideal given the implementation of the Integrated Resource Planning (IRP) process, the reintegration of BCTC into BC Hydro, and the current resource balance, which would not require the need to issue an RFP in the very need future

A list and description of our recommendations follow by functional area.

Energy and Demand Supply Planning

1. Link the Integrated Resource Planning process (IRP) and procurement activities, i.e. the timing and level of need for new resources should be determined through the IRP process, and assure that the IRP:
    - is consistent with government policy;
    - identifies opportunities for procurement;
    - is the vehicle to conduct analyses regarding inputs and assumptions underlying the procurement process; and
    - is updated as frequently as necessary to prevent over or under supply.

Sourcing and Procurement

2. Make the Energy Procurement process more transparent for all stakeholders and First Nations:
    - Prepare Energy Procurement procedures, as well as a Code of Conduct, for undertaking procurement processes and post both on the website;
    - Develop project viability criteria and transparent weightings for price and non-price factors to evaluate bids in select procurements.

3. Implement smaller but more frequent energy procurements in the future which are linked to the IRP, as updated, and accomplish the following objectives:
    - Provide more certainty to the market regarding procurement activity;
    - Allow for quicker adjustment to market and governmental policy changes;
    - Encourage suppliers to maintain project development activity to create a more competitive market.

4. Continue to follow the recent trend in BC Hydro's procurements, combining or mixing procurement vehicles to match the type of overall solicitation being implemented:
   - Utilize a more flexible Request for Proposals (RFP) process for larger and broader (province-wide) solicitations;
   - Continue to implement other procurement vehicles such as Call for Tenders, Request for Offers, or Feed-in Tariffs for smaller or targeted resources as required.

5. For larger procurement processes, utilize a multi-stage evaluation process which includes the following stages:
   - Threshold process for eligible offers;
   - Indicative bid process combined with project viability criteria to select a short-list;
   - Best and final price offer for final bid selection[18]
   - Simultaneous competitive negotiations that allow consideration of value-added provisions such as buyout options and expiration transfers under standards that assure fairness;

6. Develop standards for evaluating and negotiating bilateral contracts and make the standards transparent to stakeholders.

7. Consider creating an Advisory Group comprised of non-supplier stakeholders and First Nations to advise BC Hydro on procurement activities. The Advisory Group would likely be comprised of stakeholders and First Nations from the IRP working group This is similar to the Procurement Review Group utilized in California as an advisory group only for energy procurement activities.

Interconnections

8. In the process of integrating BC Hydro and BCTC, assess how other utilities are addressing the following issues:
   - Providing information about the availability of transmission capacity and estimated cost to expand capacity in different regions/delivery points (e.g. PacifiCorp and California utilities);
   - Consideration of cluster studies by region (e.g. Southern California Edison);
   - Development of final portfolios from procurements based on bid price, interconnection and transmission upgrades (e.g. Hydro-Quebec).

[18] The indicative bid/best and final offer process would allow the supplier to incorporate market or project cost changes in its best and final bid. In addition, this process can be effectively integrated with the interconnection process to ensure that interconnection cost information included in system impact studies and possibly facility studies can be incorporated in final bid prices.

Evaluation and Risk Allocation

9. Complete financial analysis, in collaboration with stakeholders and First Nations, to assess if more flexible contract provisions, which shift less risk to the supplier than the following EPA provisions, achieve a better balance of costs and benefits to ratepayers. If the analysis does suggest a better balance will occur, modify the contract provisions for better alignment with prevailing industry practices:
   - The five year ratchet provision adjusting “full-price” delivery levels down to levels exceeded in 80% of the performance periods;
   - Financial penalties for over or under delivery from the first MWh;
   - Pricing intermittent resources on the basis of strict seasonal delivery requirements.

Report on BC Hydro's Energy Procurement Practices

Appendices

Merrimack Energy Group, Inc.

February, 2011

Prepared by
Merrimack Energy Group, Inc.

Merrimack
Energy

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APPENDIX A

Survey/Questionnaire on BC Hydro's Energy Procurement Practices

Background

Respondents are requested to submit responses to the following questions. Respondents could choose to identify their organization in their responses or remain anonymous. Respondents could choose to answer all or some of the questions. The questions are presented by functional area associated with BC Hydro's energy procurement practices:

1. Energy Demand/Supply Planning
2. Sourcing and Procurement
3. Project Interconnection
4. Evaluation and Risk Allocation
5. Contract Management and Payment Administration

A. Energy Demand/Supply Planning

Question 1. What role should the Integrated Resource Planning (IRP) process serve regarding the energy procurement process? Should the IRP and energy procurement process be linked? Under what circumstances should the results of the IRP affect the timing of a power call and the amount of resources solicited/selected? What information from the IRP process is most important for suppliers?

B. Sourcing and Procurement

Question 2. What are the strengths and weaknesses of BC Hydro's energy procurement practices?

Question 3. Identify and describe areas for improvement in BC Hydro's energy procurement practices and processes.

Question 4. Have you participated in power procurement solicitations in other jurisdictions? If yes, please identify the process and describe the positive aspects of the solicitation process. Please identify any positive attributes which could possibly be applied to BC Hydro's energy procurement process.

Question 5. Based on your experience please list the reasons for the attrition rate for independent power projects in British Columbia. Please rank order from the most important to least important.

Question 6. Please describe your overall view of the types of solicitations initiated by BC Hydro and the products sought. Please provide any recommendations or preferred approaches to ensure that all resources, technologies, and project sizes have an equal opportunity to compete.

Question 7. Please complete the following table which addresses the interaction between BC Hydro and the suppliers during various stages of the procurement or solicitation process. Please submit a separate response for each procurement process if preferred or provide a general response for BC Hydro's procurement processes overall. Respondents should provide specific comments below or on a separate sheet if desired.

Areas of Interaction	**Excellent or Very Responsive**	**Good or Generally Responsive**	**Average/Needs Improvement**	**Poor or Not Responsive**	**Not Applicable**	**Comments**
Procurement Process – Identify Below						
1. **Development of CFT, RFP, or other Call Documents**						
• Comments on development of documents						
2. **Bidders Conferences, Workshops and Meetings**						
• Opportunity for questions						
• Quality of BC Hydro presentations						
• Interaction with Interconnection team						
3. **Questions and Answers**						
• Quality of responses						
• Timeliness of posting responses to website						
• Level of direct contact with BC Hydro team						
4**. Preparation of Proposals**						
• Responses to questions						
• Clarity and transparency of solicitation documents						
• Quality of information provided to suppliers						
5. **Bid Evaluation**						
• Follow-up clarification questions						
• Time provided for clarification response						
• Timeliness for completing evaluation						
6. **Selection of Winning Bidders**						
• Timeliness of						

selection						
7. **Response to non-successful bidders**						
• Adequacy of feedback						
8. **Contract Negotiations**						
• Interaction during negotiation process						
• Time for completing contract negotiations						
9. **Contract management**						
• Invoicing and payment process						
• Interpretation of EPA clauses						

Question 8. How would you rate BC Hydro's energy procurement processes relative to the following characteristics: (1) fairness; (2) openness; and (3) transparency? Please explain.

C. Interconnection

Question 9. Please describe your view of the interconnection process and the impacts on your project development activity. Provide suggestions how the interconnection process can be improved.

D. Evaluation and Risk Allocation

Question 10. Do the Electricity Purchase Agreements (EPAs) generally provide an appropriate balance of risk between the utility and the suppliers? Please identify specific provisions where you feel the risk allocation is skewed. Please provide comments relative to specific calls or power acquisition solicitations.

E. Contract Management and Payment Administration

Question 11. For suppliers who have executed contracts and are operating under a contract with BC Hydro, please provide your overall assessment of the contract management process. Identify areas for improvement.

Name of Respondent: ____

Contact Person: ____

Phone Number: ____

Email Address: ____

Proposed Process for Soliciting Input from Energy Suppliers Regarding BC Hydro's Energy Procurement Practices

Background

Merrimack Energy Group, Inc. has been commissioned by BC Hydro to provide an independent assessment of the energy procurement and contract management practices of BC Hydro, with particular emphasis on the interactions with energy suppliers. The objective of this evaluation is to (a) assess current procurement practices and identify areas for improvement, and (b) assess current interactions with energy suppliers and identify areas for future enhancement of the relationship with suppliers. This energy procurement practices review will address the following functional areas:

1. Energy demand and supply planning
2. Sourcing and procurement
3. Project interconnection
4. Evaluation and risk allocation
5. Contract management and payment administration

Approach for Soliciting Input from Stakeholders

Merrimack Energy is proposing a multi-stage process design to solicit input and collect feedback and recommendations from stakeholders that will assist in improving BC Hydro's energy procurement process. The multi-stage process recognizes that it may take several iterations to fully develop recommendations and feedback on specific activities. Each step in the proposed process is described below

1. Step 1 – Survey/Questionnaire

Merrimack Energy plans to prepare a survey/questionnaire that could be distributed to energy suppliers to solicit their feedback and recommendations on the above functional areas associated with BC Hydro's energy procurement process. Our idea is to work directly with Clean Energy Association of British Columbia to solicit responses from members of the organization as an initial base of information and suggestions. We also hope the survey can illicit a number of consistent themes and suggestions that can serve as the focus of this assessment. The survey includes information gathering questions as well as several questions designed to rank specific aspects of BC Hydro's energy procurement processes. In one of the questions, we are seeking feedback on the interaction between BC Hydro and suppliers in a range of activities during a solicitation process where interaction generally occurs. A draft survey is attached for review and comments.

Respondents to the survey/questionnaire could choose to identify their organization or remain anonymous.

2. Compile Results of Survey/Questionnaire

Merrimack Energy will then compile the responses to the survey/questionnaire by functional area and prepare a summary of the comments and recommendations.

3. Follow-up Discussions with Respondents

Merrimack Energy will use the results of the survey to follow-up with specific respondents to gain additional insight into their comments or to further define the comments and recommendations. The intent of these discussions will be to further flesh out the comments and recommendations.

4. Conduct Group Meeting With Stakeholders

This step in the process is proposed to be group meetings or individual meetings with stakeholders at the IPP conference in November. Merrimack Energy proposes to distribute the list of findings and recommendations from the survey and follow-up calls to stakeholders that will attend the group meetings prior to such meetings. The purpose of the group meetings will be to further discuss and enhance the evolving recommendations. We feel in such a group setting that feedback and comments from different stakeholders will provide valuable insight and serve to flesh out the recommendations.

5. Hold Workshop With Interested Stakeholders to Discuss Results of the Survey and Review of Utility Best Practices From Other Jurisdictions

As part of this assignment, Merrimack Energy is also tasked with undertaking an assessment of best practices from other jurisdictions and utilities with regard to energy procurement practices and interactions with suppliers. In addition to sharing the results of the surveys and follow-up discussions, we will share the comments from the best practices assessment as a basis for discussion at the workshop.

Schedule

The following is our proposed schedule for completing the information collection process with stakeholders.

1. Distribute Survey/Questionnaire to Clean Energy British Columbia for review and comment – September 30
2. Receive comments and finalize survey/questionnaire – October 5
3. Distribute to Clean Energy British Columbia members – October 6
4. Receive comments from survey participants – October 13
5. Compile summary of responses and distribute to survey participants – October 15
6. Meetings with stakeholders in Vancouver – Week of October 18
7. Attend IPP Conference and conduct group meetings with stakeholders – Week of November 8
8. Conduct Workshop with interested stakeholders – Week of December 6

APPENDIX B

List of Respondents

Name	Organization
Doug Little	BC Hydro
Rohan Soulsby	BC Hydro
Bryan Corns	BC Hydro
Mark Dayton	BC Hydro
Dave Hardman	West Fraser Timber Co. Ltd.
Paul Lowry	Borden Ladner Gervais LLP
Shelley Murphy	BC Ministry of Energy
John Johnson	Cloudworks Energy, Inc.
Paul Kariya	Clean Energy BC
Loch McJannett	Clean Energy BC
Darcy Fear	Fosthall Creek Power Ltd.
Keith Boutcher	Capital Power Corporation
Ron Sanderson	IPP Developer
Richard Lemaire	Boralex Inc.
Harold Kalke	Fosthall Creek Power Ltd.
Stephen Cheeseman	Chinook Power Corp.
Paul Liddy	Cedar Road LFG Inc.
Alison Thompson	Canadian Geothermal Energy Association
Sammy Chow	Fred Olsen Renewables
Frank Lin	BC Hydro
Thomas Hackney	B.C. Sustainable Energy Association
Michael Margolick	Northland Power
Paul Sweeney	Plutonic Power Corporation
Harvie Campbell	Pristine Power Inc.
Jim Quail	B.C. Old Age Pensioners Organization
Les MacLaren	B.C. Ministry of Energy
Bill Adams	Domtar Pulp and Paper
Randy Reimann	BC Hydro
Michael Towers	Tolko Industries Ltd.
Dave Kusnierczyk	Greenleaf Consulting Inc.
Daryl Peters	TTQ Economic Development Corp.
Richard Stout	Joint Industry Electricity Steering Committee
Dave Craig	Commercial Energy Consumers Association
Colin Coolican	Regional Power, Inc.
Judith Sayers	First Nations Representative
Caroline Findlay	Blake, Cassels & Graydon LLP

APPENDIX C

Summary of Utility Procurement Processes

Issue	Utility
	Hydro-Quebec
A. Energy Demand/Supply Planning	
• Basis for Planning	Every 3 years, Hydro-Quebec Distribution prepares a Supply Plan covering the next 10 years. This plan presents forecasts of its customers electricity requirements, taking into account energy efficiency measures that have been implemented, along with the various means that the division intends to use to ensure a secure supply of electricity for Quebec. The Supply Plan is subject to an annual update. The November 2007 Supply Plan was approved by the Regie in October 2008.
• Mechanism for determining issuance of RFP/CFT	As stated in Hydro-Quebec's Call for Tenders and Contract Award Procedure ("Procedure"), the date for issuing the Call for Tenders is determined by Hydro-Quebec Distribution based on the needs identified and the time required to complete the Call for Tenders. The Triennial Supply Plan may provide specific timetables for different call for tenders. When such timetables are provided for in the plan, the Regie may review them if need be, at the time of the supply plans yearly update. Also, as stated in the Procedure, Hydro-Quebec must enter into power supply contracts to satisfy Quebec market needs beyond those of the heritage pool electricity and to purchase blocks of energy determined by regulation of the Government. To this end, Hydro-Quebec Distribution must issue Call for Tenders to potential suppliers. The Procedure sets out the procedures to be followed for these Call for Tenders and the awarding of resulting contracts. The Government of Quebec also plays a major role in deciding when a Call for Tenders will be issued, the products to be solicited, and the evaluation criteria, particularly the criteria related to local and regional economic development.
• Lead time for issuance of RFP	Hydro-Quebec generally announces the issuance of the RFP far in advance of when the bids are due to allow the bidders to develop detailed and comprehensive proposals. For example, the most recent Call for Tenders (A/O 2009-02) for Wind-Generated Electricity for a Total of 500 MW (block of 250 MW from Aboriginal projects and a block of 250 MW from Community projects) was issued on April 30, 2009 and bids were due June 6, 2010.
• Role of Stakeholders	The role of stakeholders outside the Government of Quebec is limited.
• IRP Approval Process	The Supply Plan must be approved by the Regie
• Other Planning Considerations	The Call for Tenders processes undertaken by Hydro-Quebec Distribution are governed by the "Call for Tenders and Contract Award Procedure" and the "Code of Ethics on Conducting Call for Tenders", both of which are located on Hydro-Quebec's website.
B. Sourcing and Procurement	
• Recent Solicitations	Hydro-Quebec has been conducting long-term solicitations since 2001. Examples of Call for Tenders include: (1) Call for Tenders for Baseload and Cycling Resources – 1,200 MW – 2003; (2) Call for Tenders for Electric Generating Facilities Using Biomass – 100 MW – 2003; (3) Call for Tenders for Wind Generated Electricity – 1,000 MW – 2004; (4) Call for Tenders for Electricity Generated by Cogeneration – 350 MW –

	2005; (5) Call for Tenders for 2,000 MW of Wind-Generated Electricity – 2,000 MW – 2007; (6) Call for Tenders for Energy Produced by Biomass Cogeneration – 125 MW – 2009; (7) Call for Tenders for Wind Generated Electricity for Aboriginal Projects and Community Projects – 500 MW – 2010.
• Frequency of Solicitations	The number of solicitations per year has averaged about 1 per year. However, there have been periods where no solicitations have been issued for a few years and other cases where there are two solicitations within one year timeframe.
• Solicitation Strategy	Hydro-Quebec Distribution has initiated Targeted solicitations where the bids requested are generally for the same product, including the wind Call for Tenders and the biomass CFTs, where the about of capacity requested has been identified in advance.
• Time for Completing Solicitation	As previously noted, the Hydro-Quebec solicitation process is a lengthy process designed to ensure viable projects and solid entities from a financial perspective are the one selected
• Type of Solicitation	Targeted solicitations – i.e. wind-only solicitations; Biomass solicitations, etc.
• Stakeholder Involvement	Stakeholder involvement has been somewhat limited. Hydro-Quebec does hold a bidders conference shortly after release of the RFP. The Procedure also states that HQ will work with an expert.
• Interaction with Suppliers Throughout the Process	Hydro-Quebec accepts questions from suppliers prior to submission of proposals and posts all Q&As on the website. Once bids are submitted, all interaction between Hydro-Quebec and the bidders is initiated through Deloitte, which serves as Official Representative. Deloitte is also responsible for ensuring that Hydro-Quebec adheres to the Call for Tenders and Contract Award Procedures.
• Role of Utility Own Resources	Proposals from Hydro-Quebec Generation were acceptable in the first CFT process.
• Expected Trends in Procurement Process	Hydro-Quebec has over-procured power through Call for Tenders and expects that any future solicitations will be focused on specific sectors or applications. Recent examples such as the biomass cogeneration Call, the small scale hydro Call, and the 500 MW Call for Aboriginal and community projects are examples. With the exception of the first call conducted in 2002-2003, all calls have been for renewable resources.
• Unique Aspects of Solicitation Process	There are several unique aspects of Hydro-Quebec's process: • Call for Tenders Committee and its functions • Over 90% of the criteria have been developed as objective criteria • The long lead time between issuance of the RFP and receipt of bids means that most of the proposals received are fairly mature and well developed • Hydro-Quebec is committed to a schedule for completion of the Call for Tenders and has maintained its schedule • HQ has had a lower failure rate than in most jurisdictions • Contract negotiations and approval processes are very short – 4-5 months for negotiations and approval
• Use of Independent Evaluator/Fairness Advisor	Deloitte serves as Official Representative on the solicitation process. Merrimack Energy serves as Technical Advisor on all solicitation processes. In that role, Merrimack Energy conducts an independent evaluation of the bids received and works with Hydro-Quebec's bid evaluation team to ensure the evaluation and scoring is fair and accurate. Representatives of Merrimack Energy and Deloitte also are members of the Call for Tenders Committee which is also comprised of the President of Distribution, Director of Energy Supply, the Project Manager, and internal counsel. The Call for Tenders Committee is responsible for approving Project Management decisions at each step in the process (Minimum Requirements, Short List selection, and Final Award). The minutes of each meeting are sent to the Regie after the meetings.

C. Interconnection	
• Interconnection Study Process	Potential bidders have the option of requesting that Hydro-Quebec TransEnergie conduct an exploratory study for connection of the wind farm or other resource in order to obtain an indication of the connection scenario and costs. This additional step is intended to avoid having significant costs incurred in the preparation of a bid where the electricity transmission costs would be prohibitive and not make the bid very competitive. The exploratory study provides a parametric estimate of the costs related to a possible integration scenario for the project involved in the request. Since the aim of the study is solely to provide a brief estimate of the costs and lead times involved in carrying out an integration scenario at the request of the potential bidder, it should never be interpreted as a final integration solution. More in depth studies have to be done at the time of the bid assessment and, if applicable, after the Facilities Study Agreement has been signed in view of an integration of the wind farm to the system. Once the bids are received, the studies for estimating the cost of system connection and reinforcement, as well as the applicable electrical loss rate, is conducted during Step 2 of the selection process by Hydro-Quebec TransEnergie at Hydro-Quebec Distribution's request. Bidders are required to provide technical information on their projects and include such information in their bid. If a bidder is retained to execute a contract, it shall sign a Facilities Study Agreement as well as a Connection Agreement with Hydro-Quebec TransEnergie to have the work carried out, in accordance with the rates and conditions of Hydro-Quebec's Open Access Transmission Tariff.
• Time and Data Requirements for Completing Interconnection Studies	With regard to the exploratory study, for the 500 MW Wind Call for Tenders the deadline for submitting the exploratory study request form was December 1, 2009 and the due date for submission of proposals was July 6, 2010. The cost for the exploratory study is $5,000 per project. It takes about 6 weeks to complete an exploratory study, starting from the date on which all of the required information has been provided to Hydro-Quebec TransEnergie. In addition, Hydro-Quebec TransEnergie conducts summary studies of each project in Step 2 of the evaluation to determine how long it will take to interconnect the specific project and the estimated cost to interconnect as well as the cost of the transmission upgrades. In Step 2, therefore, TransEnergie will conduct the summary study to determine a connection scenario for each bid. On the basis of this scenario, TransEnergie will estimate the cost of the substation, which is added to the cost of the wind farm collector system as estimated by the bidder, up to Hydro-Quebec's maximum contribution applicable to the cost of the switchyard. Hydro-Quebec TransEnergie will also provide an estimate of the cost of connection to the regional system, the electrical loss rate and the time required to complete the work. If the proposed project results in investments being avoided or deferred, which would otherwise have been required as part of the expansion of Hydro-Quebec TransEnergie sysem, these avoided costs will be estimated for the project. In Step 3, TransEnergie will assess the combination of offers based on the short listed bids from Step 2. The cost of reinforcing the bulk transmission system is evaluated for each combination of bids. The analysis in Step 2 and 3 is done consistent with the schedule identified by Hydro Quebec for each Call for Tenders. In the case of the 500 MW Wind Call for Tenders, bids were received in July and final selection in due in early December 2010.

• Cost and Responsibility for Completing Studies	The connection and system reinforcement work on the transmission and distribution systems is executed by Hydro-Quebec TransEnergie. The associated costs are borne by Hydro-Quebec TransEnergie. Accordingly, these costs are not taken into account when determining the price of electricity offered by the bidder. However, before the start of the Facilities Study and then the work on the system, Hydro-Quebec TransEnergie requires the bidder to deposit security covering the reimbursement of such costs in the event that the project to be connected does not materialize as per the timetable. The amount of such security is equal to the cost of the studies and the work required to integrate the project to the Hydro-Quebec system.
• How are results of the Interconnection Study used in the Evaluation	As noted, interconnection and transmission costs are estimated for each bid in Step 2 of the evaluation and for bid combinations in Step 3 of the evaluation. The impact on transmission costs takes the following into account: • Cost of connecting the wind farm to the regional transmission (315 kV and less) or distribution system, including the cost of modifying the regional system lines and substations and, if applicable, the curtailment cost • Cost of the wind farms switchyard as defined in the Call for Tenders • Electrical loss rate associated with the wind farm's generation • Avoided costs associated with future transmission system investments, if applicable • Cost of reinforcing the bulk transmission system (735 kV) as a result of adding new wind farms (only in Step 3).
• Unique Aspects of Interconnection and Transmission Analysis Process	Hydro-Quebec Distribution and Hydro-Quebec TransEnergie work very closely together on the evaluation process, even though each organization is a separate business unit. However, Hydro-Quebec does not meet FERC requirements for open access and separation of the functions. The interaction of the two organizations and expectations that TransEnergie staff will assist Hydro-Quebec Distribution in a Call for Tenders process results in the transmission assessment being completed in the expected amount of time no matter how many bids are received.
• Areas for Improvement	N/A
• Other Issues	N/A
• Allocation of Interconnection and Transmission Costs	See Above
D. Evaluation and Risk Allocation	
• Evaluation Process	Hydro-Quebec consistently follows a Three Step process for evaluating bids. The three steps are: (1) Evaluation of Bids per the minimum requirements; (2) Ranking of Bids; and (3) Simulation of bid combinations. In the first step, bids that do not meet the minimum requirements for the criteria that are established in the CFT are not retained for future consideration. In the second step, the remaining bids are divided into categories according to the features of the products offered. Each bid is studied individually without taking into account any possible interactions with other bids. An evaluation of cost and non-monetary criteria is conducted. The results are weighted using pre-specified weights for each criteria. The bids are ranked by scores and a short-list is selected. The pricing reflects the bid price and transmission costs estimated by TransEnergie.

	In the third step, monetary or cost criteria are evaluated in more detail taking into account possible combinations of bids. Transmission costs for the bid combinations are also taken into consideration at this step. The result of this step is the selection of the projects chosen for contract execution. The Call for Tenders states that the contracts shall be awarded to the bidders that submitted the bids that resulted in a combination with the lowest price in $/MWh for the quantity of electricity and the conditions requested while taking into account the applicable transmission costs. Contract negotiations with bidders are limited.
• Evaluation Criteria (e.g. importance and weighting of price and non-price factors)	The evaluation criteria vary by solicitation. In the recent 500 MW Wind Call for Tenders the following criteria were applied: Minimum Requirements: • Bidder has to demonstrate site control • Price of electricity must be below the cap • Bidder must demonstrate experience in at least one similar project • Aboriginal groups and communities must demonstrate a minimum interest in the capitalization of the project • The technology must be mature • The project must be able to be interconnected to the grid in time to meet the date requested by the bidder for COD. TransEnergie completes this evaluation. • Bidders must guaranteed a specified region and Quebec content • Bidders must have wind measurements at the site for at least 8 months (including the December through March period) prior to bid submission. The evaluation criteria in Step 2 include the following with the weights used: • Cost of Electricity – 30% • Regional content beyond minimum requirements – 15% • Regional content beyond minimum requirements – 10% • Sustainable development – 25% • Financial Capability – 7% • Project feasibility – 7% • Relevant experience – 6% The weights and some categories vary in other Call for Tenders. Also, there are sub-criteria within the major criteria listed above. The sub-criteria are described in detail in the Call for Tenders document but the bidder is provided the specific weights of the sub-criteria.
• Transparency of Evaluation Criteria	The Hydro-Quebec process is a very transparent process in that bidders are provided a significant amount of information about the bid evaluation and selection process as well as the weights for the higher level and sub-criteria categories. In addition, the scoring methodology is highly objective with even subjective criteria quantified as much as possible. Close to 90% of the weightings are objective.
• Evaluation Methodology	With the exception of the first Call for Tenders undertaken by Hydro-Quebec for conventional baseload and cycling facilities, all other Call for Tenders have been targeted solicitations with like resources competing against one another (e.g. wind projects only, biomass only, etc.). As a result, Hydro-Quebec has generally used a real levelized cost analysis as the basis for the Step 2 evaluation with the real levelized cost based on the bid price formula proposed. For Step 3 combinations, Hydro Quebec may use a linear programming

	model to determine the cost of the best combination of bids based on the large number of constraints usually included in each solicitation.
• Are Model Contracts Included With the Solicitation Documents	Yes. A detailed model contract (with limited opportunity for revisions) is included in the Call for Tenders package.
• Presence of Mandatory Provisions	N/A
• Role of Contract Negotiations	Hydro-Quebec states in its Call for Tenders document that the terms and obligations of the contract to be signed by the parties shall conform to those of the Standard Contract, with the exception of the changes needed to reflect the characteristics specific to the bid. Should the parties fail to agree on the changes to be made to the Standard Contract in order to take into account the specific features of the bidders bid, Hydro-Quebec may end the discussions after giving the bidder advance notice of 7 days. A bidder from the back-up list is then chosen and a deadline is fixed by the Distributor for the closing of a contract.
• Identification of Most Contentious Contract Provisions	Bids with regional and Quebec content requirements must guaranteed such requirements in the contract and are subject to contract penalties if the level of regional and Quebec content is lower than the contract amounts.
• Contract Approval Process	When a contract is final, the parties proceed with the execution of the contract. Its enforcement is subject to the Regie's approval under the conditions and in the cases determined by regulation of the Regie. If the Regie does not approve the contract it is terminated. Along with its request for the approval of the contract, the Hydro-Quebec Distribution submits to the Regie a report providing the results of the evaluation of bids, when a mandated firm has been retained, its report regarding the application of the bid evaluation methods as well as the Call for Tenders procedures. If contract approval is not forthcoming from the Regie within 120 days following submission of the contract, the Supplier may cancel the contract by sending 10 days prior written notice.
• Level of Contract Simplification	N/A
E. Contract Management	
• What Department Within the Utility Manages Power Contracts	Within Hydro-Quebec there are two units responsible for managing the power contracts. One managing PPAs signed by Hydro-Quebec Production and one managing the PPAs signed by Hydro-Quebec Distribution. At Hydro-Quebec Distribution, Energy Supply is responsible for the procurement and management of electricity supply contracts.
• Relationship to Energy Procurement Function	Energy Supply is also responsible for energy procurement activities, including implementing the Call for Tenders issued by Hydro-Quebec Distribution.
• Major Issues Related to Contract Management	Major issues are mostly on the contract administration side, before, during and after the contract period.
• Lessons Learned Related to Contract Management	N/A
• Contract Management Tools or Procedures	Hydro-Quebec uses different tools such as MS Projects, and other tools developed specifically by Hydro-Quebec such as OPA for invoicing and measuring.

Issue	Utility
	Arizona Public Service Company
A. Energy Demand/Supply Planning	
• Basis for Planning	Integrated Resource Plan; APS annual Renewable Energy Standard Implementation Plan; IRPs filed every two years; discussions about procurements are a component of the discussions on IRP issues; Certification of new resource planning rule in 2010. The rule requires explicit consideration of major risks, resource options, and proposed solutions.
• Mechanism for determining issuance of RFP/CFT	Solicitations are aligned with resource plans, regulatory rules, standards and commitments. All acquisitions, inside or outside of an RFP, will require a market test. In 2009, in a Rate Case settlement there was agreement to issue several renewable resource RFPs in 2010 including the Wind Only RFP. The Settlement called for 1.7 million MWh of additional renewables by 2015.
• Lead time for issuance of RFP	RFPs are issued within a 3-4 months of initiation of the requirement to issue the RFP. APS uses a fairly standard format and evaluation criteria.
• Role of Stakeholders	The IRP process has major stakeholder involvement including market participants, policy makers, and other industry stakeholders. As an example, for the 2010 IRP, APS has held monthly meetings which have included presentations by APS staff and other stakeholders on key issues including resource procurement.
• IRP Approval Process	IRP process is undertaken on a two year cycle. The utility requests Commission approval of the Resource Plan or acknowledgement that APS considered all relevant resources, risks and uncertainties. The process generally takes 9 months from initiation to filing with the Commission.
• Other Planning Considerations	Arizona has a 15% Renewable Energy Standard by 2020.
B. Sourcing and Procurement	
• Recent Solicitations	In the last seven years APS has conducted 14 formal solicitations, adding 660 MW of renewable resources and 2,316 MW of conventional resources. Since 2008, APS has completed 5 targeted renewable resource solicitations including: (1) Renewable Distributed Energy solicitation in 2008; (2) Small Renewable Generation in 2009; (3) PV solicitation in 2010; (4) Arizona Wind Only solicitation in 2010; and (5) Small Renewable Generation in 2010
• Frequency of Solicitations	APS is issuing solicitations on an annual basis. In 2010 APS issued three major solicitations (Wind, Utility-scale PV, and Renewable Small Generation) as well as very select solicitations (Distributed residential PV systems in Flagstaff, Arizona, RELP Solar RFP for solar PV systems on selected government buildings, LIRPP PV Solar for multifamily residential complexes, and a community based solar PV program).
• Solicitation Strategy	APS' recent solicitations have been very targeted solicitations and have involved both IPP type projects as well as distributed resources. Several recent solicitations have involved specific customer segments as well as customer involvement such as the Renewable Distributed Generation Solicitation.
• Time for Completing Solicitation	For the Arizona Wind Only RFP, the RFP document was prepared during December and January 2009-2010. The RFP was released on January 27, 2010. Bids were due on April 14, 2010. Short Listed bidders were notified on June 4, 2010 and Final Selection Notification and contract completion was late July 2010. It has been Merrimack Energy's experience that the time for completing a solicitation by APS has generally been 6-8 months. APS really focuses on maintaining its schedule.

• Type of Solicitation	Arizona Wind Only RFP and Renewable Small Generation RFP are examples of recent solicitations. Merrimack Energy has served as Independent Monitor for both solicitations as well as the Renewable Distributed Energy RFP.
• Stakeholder Involvement	Stakeholder involvement is very limited during the solicitation process. The main involvement by stakeholders is during the IRP process or other regulatory docket which deals partially with procurement issues. The Commission or its staff is not involved during the solicitation process or in the preparation of the bidding documents. The Commission may establish the parameters of the solicitation via regulatory decision but the utility is responsible for carrying out the solicitation. Merrimack Energy has served as Independent Monitor for three major solicitations and has had no discussions with Commission staff or suppliers throughout the process
• Interaction with Suppliers Throughout the Process	During the solicitation process, there is very little interaction between the utility and suppliers. Suppliers and other stakeholders have no role in the design of the RFP and related documents. APS holds a bidders conference that is generally limited to about 1 hour. There are generally few questions from bidders. APS posts any questions and responses on its website for the specific RFP. There is also one-on-one interaction between the bidder and APS project team management during the process focused on issues associated with a specific project question or issue. Once the short list is selected there is generally more interaction with suppliers but again it is somewhat limited. APS does invite the short listed bidders to meet face-to-face for either one-half day to discuss their project, including any updates or issues. The schedule and issues for negotiations are generally discussed, although this is not a formal negotiation.
• Role of Utility Own Resources	Utility-owned resources are not competing in renewable solicitations. For the Arizona Wind Only RFP, APS indicated an interest in receiving bids for both PPAs as well as turnkey bids on the bidder site which would be owned by APS.
• Expected Trends in Procurement Process	APS' procurement process has been evolving to reflect a range of creative solicitations designed to target not only different resource options but also to target different rate classes such as residential and commercial solar options as well as customer-supported larger scale distributed renewable (primarily PV) systems.
• Unique Aspects of Solicitation Process	The procurement processes instituted by APS have several unique aspects: • The RFPs target both large and small scale markets and applications • APS generally does not include a model contract in its solicitations • APS' bid evaluation methodology has been designed to compare the costs and benefits of each proposal and calculate the ratio of costs to benefits for each option. • APS has probably initiated more solicitations involving specific customer segments than any other utility we have noticed.
• Use of Independent Evaluator/Fairness Advisor	The Arizona bidding rules require the utility to use an Independent Monitor for its solicitations. The Commission has outlined the requirements and role of the Independent Monitor in the solicitation. APS may select from a pre-approved pool of Independent Monitors approved by the Commission.
C. Interconnection	
• Interconnection Study	APS operates under a FERC-approved open access transmission tariff. APS is required therefore to study large generators and small generators

Process	separately and perform feasibility studies serially. APS first accepts an application for interconnection. APS also completes three studies for the generator seeking interconnection: (1) feasibility study; (2) system impact study, and (3) facilities study. The bidder is responsible for the costs to complete all three studies. APS recently submitted a waiver to FERC allowing the Company to waive APS' first come first serve interconnection study order for Interconnection Requests in the Gila Bend area of its system to allow APS to conduct a clustering study for projects in this region applying to the Renewable Small Generation RFP.
• Time and Data Requirements for Completing Interconnection Studies	APS has a large generator interconnection queue. In accordance with the provisions set forth in Section 4.2 of Attachment O (LGIP) of APS Open Access Transmission Tariff, APS has elected to evaluate Large Generator Interconnection Requests utilizing clustering for the purpose of conducting the Interconnection System Impact Study.
• Cost and Responsibility for Completing Studies	The Interconnection customer shall pay the actual cost of the interconnection studies.
• How are results of the Interconnection Study used in the Evaluation	The results of the interconnection studies are not used specifically in the evaluation.
• Unique Aspects of Interconnection and Transmission Analysis Process	For the Wind RFP, APS will accept bids for sites in constrained areas. However, due to known APS transmission constraints and to further aid bidders in their determination of RFP participation, APS has identified a constrained transmission area that will require transmission upgrades in order to deliver firm project output to APS load centers over all hours of the year. These upgrades may add significant costs to the project bid as part of APS screening. In the absence of transmission upgrades, APS can still accept delivery of energy in the transmission constrained area. Projects in constrained areas will be assigned a 0% capacity value and a 5% reduction in delivered energy for potential curtailments. A project obtaining transmission wheeling on another transmission provider's (non-APS) transmission system can avoid the identified constraint.
• Areas for Improvement	
• Other Issues	The RFP states that if a generating unit is not yet operational and will be interconnected to APS' transmission or sub-transmission system, but an interconnection request has not been submitted at the time of the Proposal, the bidder is notified that it is responsible for completing an Application for Generator Interconnection in accordance with the proposed construction schedule.
• Allocation of Interconnection and Transmission Costs	
D. Evaluation and Risk Allocation	
• Evaluation Process	APS conducts a three-stage evaluation process comprised of the following steps: (1) proposal threshold requirements; (2) proposal screening (quantitative and qualitative evaluation to identify the proposals that will be short listed); and (3) detailed evaluation of short-listed proposals. APS states that it reserves the right to select an offer that is not the lowest price, if APS determines that to do so would result in the greatest value to APS' retail customers.
• Evaluation Criteria (e.g. importance and weighting of price and non-price	Proposals must first meet the threshold requirements. Threshold requirements are not rigid but generally fairly lenient. Proposals that meet threshold requirements will undergo a quantitative and qualitative evaluation to identify proposals that will be short listed. Price will be a

factors)	major factor, but APS will consider other qualitative risk factors
• Transparency of Evaluation Criteria	While APS identifies the evaluation criteria, there are no weights identified in the RFP or included in the evaluation and selection process. APS may select a higher cost project if it deems a lower cost option is too risky based on its qualitative evaluation. Qualitative criteria used by APS include: • Technology assessment • Project viability • Developer experience • Financing, including financing plan, access to capital, transaction structure, and investor relations • Credit risk (based on financial statement review and post-development security • Interconnection • PPA risk
• Evaluation Methodology	The quantitative evaluation methodology used by APS is designed to compare costs and benefits of each proposal. The cost of the proposal consists of: (1) the bid price, plus (2) transmission wheeling and system upgrade cost, plus (3) integration costs, where integration costs consist of system integration costs. Due to the intermittent nature of wind generation resources, APS has added additional costs to compensate for increased resource and regulating reserve required for energy output intermittency and forecast uncertainty. APS added a value of $3.25/MWh flat for the term of the contract based on a study of such costs prepared by Northern Arizona University, plus (4) imputed debt The net present value of the cost stream was calculated and levelized over the term of the contract based on the Company's discount rate. APS also calculates the benefits associated with each proposal. The benefits consist of the value of energy and capacity associated with the resource. The benefits include: (1) Avoided Energy costs based on the hourly system avoided costs based on a PROMOD simulation of the APS system. The hourly avoided energy costs are applied to each bid based on the 12x24 generation profile submitted by the bidder (2) Avoided Capacity cost based on the market prices for a proxy peaking resource including related transmission and gas pipeline charges times the capacity value of the resource based on its maximum hourly capacity. APS discounts the benefit stream and then calculates the levelized bid cost as a percentage of the levelized avoided cost. Projects with the lowest ratio are ranked highest.
• Are Model Contracts Included With the Solicitation Documents	APS includes model contracts with some solicitations but mot others. For example, APS included both a PPA and Turnkey contract with the Arizona Wind RFP but not with the Renewable Small Generation RFP.
• Presence of Mandatory Provisions	There are no mandatory provision specifically identified
• Role of Contract Negotiations	Contract negotiations are an important aspect of APS' solicitation process. APS generally establishes a fixed timeframe to complete negotiations and holds to the schedule. APS therefore encourages bidders to conform their PPA, including markups, to the provisions included in the model PPA.

• Identification of Most Contentious Contract Provisions	For the recent Wind RFP, the most contentious issue was the security requirements required by APS.
• Contract Approval Process	APS files the contracts executed with the counterparty to the Commission for approval.
• Level of Contract Simplification	
E. Contract Management	
• What Department Within the Utility Manages Power Contracts	The same group within the Company that is responsible for procurement activities also does the contract negotiations and manages the contracts.
• Relationship to Energy Procurement Function	See above
• Major Issues Related to Contract Management	Transition from contract execution to follow project status.
• Lessons Learned Related to Contract Management	Preferable to have a manageable number of milestones. APS talks to suppliers very frequently, particularly during the project development process.
• Contract Management Tools or Procedures	APS had adopted the Primavera P6 program (critical path software) to keep track of the project development process for projects under contract.

Issue	Utility
	PacifiCorp
A. Energy Demand/Supply Planning	
• Basis for Planning	PacifiCorp undertakes a detailed and sophisticated Integrated Resource Planning process. The IRP is developed with considerable public involvement from state utility commission staff, state agencies, customer and industry advocacy groups, project developers, and other stakeholders. The key elements of the IRP include a finding of resource need, focusing on the first 10 years of a 20-year planning period; the preferred portfolio of supply-side and demand-side resources to meet this need; and an action plan that identifies the steps taken during the next two to four years to implement the plan. The IRP is prepared on a biennial schedule, filing its plan with the state utility commissions each odd-numbered year. The Company updates its preferred resource portfolio and action plan in even-numbered years by considering the most recent resource cost, load forecast, regulatory and market information. A major issue in the current IRP is assessment of wind integration costs.
• Mechanism for determining issuance of RFP/CFT	The Resource Supply Requests for Proposals are initiated from the Action Plan within PacifiCorp's Integrated Resource Plan PacifiCorp uses the input assumptions in the IRP, the resources identified for the next increment of supply, and an updated demand forecast as the basis for conducting the evaluation of the bids received.
• Lead time for issuance of RFP	In Utah, which contains PacifiCorp's most significant load, the Commission must approve PacifiCorp's RFP. In the past, the approval process has involved workshops with stakeholders facilitated by the Independent Evaluator as well as comments from stakeholders and formal hearings on the RFP. The approval process can take 4-6 months.
• Role of Stakeholders	As noted above, the IRP process involves significant stakeholder input and a large number of workshops and meeting on key issues associated with planning processes.
• IRP Approval Process	See above
• Other Planning Considerations	PacifiCorp has a $6 billion investment plan to expand its transmission in the West. Transmission planning is included as part of the IRP. PacifiCorp's IRP is one of the most sophisticated plans in the US and is vetted through 4 public utility commissions.
B. Sourcing and Procurement	
• Recent Solicitations	PacifiCorp has one currently active solicitation at this time for baseload, intermediate, and Summer peak (Q3) purchases for potentially up to 1,500 MW over the 2014-2016 timeframe. Bidders could offer PPAs, Tolling Service Agreements, and turnkey projects on a PacifiCorp site. PacifiCorp has also issued several RFPs for renewable energy resources on an all-source basis, although the vast majority of the projects expected were wind projects. The 2008R-1 Renewable RFP was soliciting for up to 800 MW of renewables but the company signed one project for less than 300 MW.
• Frequency of Solicitations	The frequency of the solicitations varies based on the IRP and changes in load or costs. PacifiCorp has had a history with regard to its conventional generation solicitations of starting a solicitation process, putting the process on hold, reinstituting the process and then terminating contract negotiations. The track record of PacifiCorp has not been favorable to bidders.

• Solicitation Strategy	The overall objective of PacifiCorp is defined to include securing resources on the market to meet generation requirements in a least cost and reliable manner. PacifiCorp is allowed to submit a benchmark bid that is a cost of service bid that will compete with third-party bids. PacifiCorp has done turnkey or self-build projects through past solicitations for conventional generation but third-party bids for renewable resources.
• Time for Completing Solicitation	For the 2008R-1 Renewable RFP, the RFP was issued on October 6, 2008 and the due date for bid submission was December 22, 2008. The evaluation was completed in March 2009 and bid negotiations were complete in July, about 1 month late.
• Type of Solicitation	PacifiCorp generally implements an all-source solicitation for both conventional resources and renewable resources. In fact, renewable resources could compete in the conventional generation RFP if they meet eligibility requirements.
• Stakeholder Involvement	Stakeholder involvement is primarily undertaken in the RFP development phase of the process. In Utah, the Independent Evaluator and Energy Division staff are directly involved in monitoring the solicitation process. The Independent Evaluator and staff report back to the Commission if needed.
• Interaction with Suppliers Throughout the Process	The vast majority of the interaction with bidders occurs via questions and answers posted on the Utah website. PacifiCorp does interact with bidders once the bids are received and reviewed by PacifiCorp for conformity with the RFP requirements. In this stage of the process, PacifiCorp prepares a term sheet or bid summary and works with the bidder to ensure all input information into PacifiCorp's models are accurate. The Independent Evaluator monitors all interactions with suppliers including monitoring contract negotiations.
• Role of Utility Own Resources	The Bidding Rules in Utah and Guidelines on Oregon allow the utility to propose a self-build option. The Independent Evaluator is required to review the benchmark resources to ensure the costs and operating parameters are reasonable and the utility is not trying to low ball bids. In addition, PacifiCorp has put its own site up to bid on a turnkey basis. PacifiCorp also entertains acquisition of existing resources through an RFP process.
• Expected Trends in Procurement Process	PacifiCorp has been at the forefront with regard to credit requirements and security as well as including out provisions in the contract.
• Unique Aspects of Solicitation Process	In the most recent all-source conventional RFP, PacifiCorp adopted an indicative bid and best and final offer process based on lessons learned in previous RFP. Under this process, bidders were required to submit indicative price bids. The bid prices will be used to determine along with non-price factors if the bid would be selected for the short-list. Once on the short-list, within four months of submittal of the indicative bid, the bidders are required to provide their best and final offer with the caveat that the price bid in the best and final could not be more that 10% higher than the indicative bid.
• Use of Independent Evaluator/Fairness Advisor	Both Utah and Oregon require the use if an Independent Evaluator. Merrimack Energy has served as the Utah Independent Evaluator for several solicitations.
C. Interconnection	
• Interconnection Study Process	PacifiCorp follows the traditional FERC process of (1) preliminary activities – 30-45 days; (2) Feasibility study – up to 45 days for a large generator interconnection study; (3) System Impact Study – up to 90 days; (4) Facilities Study – up to 90 days; (5) Generator Interconnection Agreement – Approved project up to 60 days; and (6) Executed GIA – Construction can take 2-4 years.
• Time and Data Requirements for	See above

Completing Interconnection Studies	
• Cost and Responsibility for Completing Studies	All costs required to upgrade PacifiCorp's electrical infrastructure (integration costs) will be considered in the overall economics of the resource. The Bidder must include interconnection costs in their proposal and other costs (e.g. applicable transmission wheeling expenses) necessary to deliver the energy to an interconnection point on PacifiCorp's system. Once the Bidder is selected, PacifiCorp's transmission function has the option of funding the interconnection upgrades or requiring the Bidder to fund such upgrades and then receive revenue credits per PacifiCorp's OATT.
• How are results of the Interconnection Study used in the Evaluation	PacifiCorp has developed an Attachment 13 for cost assumptions for integration costs at each major delivery point. Should a bidder select an alternative delivery point the bidder must request that PacifiCorp provide an estimate for interconnection. PacifiCorp will use the best information it has available to undertake the bid evaluation assessment for transmission costs.
• Unique Aspects of Interconnection and Transmission Analysis Process	For the conventional resources RFP, PacifiCorp is interested in proposals that demonstrate that they can deliver the power to the PacifiCorp system. The RFP identifies actual delivery points of interest as well as the estimated resulting costs for any upgrades required at the delivery point. All proposals are contingent on the ability of PacifiCorp to designate the proposed resource as a network resource.
• Areas for Improvement	
• Other Issues	Merrimack Energy as Independent Evaluator for the Utah Public Service Commission requested that PacifiCorp hold a workshop for bidders on transmission issues to explain the basis of cost estimates on Attachment 13 as well as describe the generator interconnection process. For the last two RFPs, PacifiCorp has held such workshops and they have been well attended.
• Allocation of Interconnection and Transmission Costs	See above. The costs associated with transmission upgrades are the responsibility of PacifiCorp Transmission and are included in transmission rates.
D. Evaluation and Risk Allocation	
• Evaluation Process	PacifiCorp undertakes a multi-stage evaluation process for all solicitations. Step 1 involves a price and non-price screen to determine a list of bids that will be deemed an initial short list. Price is weighted at 70% and non-price at 30%. The price points are allocated to proposals based on a pre-specified range of scores relative to market price projections. For both renewable and conventional resources, Step 2 involves a production cost run to assess which offers are selected under a range of market price assumptions. The methodology varies for renewable and conventional resources in that some of the important scenarios involved in the evaluation of conventional resources include CO2 cost cases. For conventional resource RFPs there is a Step 3 process that involves detailed risk assessments and portfolio optimization analysis to evaluate the portfolios identified in Step 2. The remaining discussions below will focus on evaluation of renewable resources only.
• Evaluation Criteria (e.g.	As noted, price accounts for 70% of the weight in Step 1 and non-price accounts for 30%. The RFP document lists the high level non-price

importance and weighting of price and non-price factors)	criteria and their weights. These include: • Conformity to RFP requirements – 6% • Conformity to pro forma PPA or Build-Own-Transfer Agreement – 6% • Status of project development – 6% • Bidder's experience – 6% • Performance guarantees – 6%
• Transparency of Evaluation Criteria	The evaluation criteria are reasonably transparent. The bidder knows the higher level evaluation criteria but does not know exactly how it will be evaluated from a price and non-price basis. From a price perspective, the bidders score is based on its relative ranking to all other proposals. From a non-price perspective, there are more detailed criteria that the Company uses to evaluate the bids.
• Evaluation Methodology	PacifiCorp uses its Alternative Cost for Compliance (ACC) methodology for evaluating bids for final selection once the short list is determined. The ACC method attempts to calculate the net benefits of a renewable energy resource. Bids which generate the most net benefits (or the least negative impacts) on a dollars per MWh basis will be selected for the final award group. While PacifiCorp used its forward price curve as the basis for assessing bids in the initial short list evaluation stage, in this assessment the Company essentially estimates its system avoided cost based on running the PaR model (Planning and Risk model). As noted, the Company first runs PaR with the preferred renewable portfolio from its latest IRP, including resources selected or under consideration. The result is a baseline value of the portfolio by analyzing the average cost of 100 separate least cost dispatch solutions based on different assumptions about gas prices, wholesale electric prices, load, thermal outages, and hydro generation levels. PacifiCorp then removes the proxy renewable resources from the plan and re-runs the PaR model. The model then calculates the cost to replace the proxy resources by either redispatching the system resources or purchasing or selling power from or into the spot market. The additional costs are divided by the generation produced by the proxy resources to determine the avoided cost (in $/MWh) or renewable resources. The net benefits of the bid are calculated as the avoided cost less the bid cost adjusted for integration costs, capacity value and terminal value. The ACC value is that value which results in the net benefits equaling to zero. Negative ACC values imply that the benefits exceed the cost of the resource. Positive values indicated that the costs exceed the benefits. In summary, ACC = (System Benefit – Cost of Energy + Production Tax Credit – Cost of Capacity + Capacity Credit + Terminal Value – Cost of Integration) Integration costs were calculated for each region of PacifiCorp's system and for each identified zone. There was no one specific adder for all wind resources.
• Are Model Contracts Included With the Solicitation Documents	Yes. PacifiCorp included both a PPA and Build-Own-Transfer Agreement in the RFP. Bidders were requested to submit red-line comments with its proposal.
• Presence of Mandatory Provisions	The non-price factors include a criterion to address compliance with pro-forma contract provisions. PacifiCorp will rank bids lower which take exceptions to the contract that shifts risk to customers.
• Role of Contract Negotiations	Contracts are actively negotiated. PacifiCorp negotiates both price and non-price factors during post-bid negotiations.
• Identification of Most	Credit requirements proved to be the major contract issue by far as one bidder who was selected withdrew because of the credit requirements.

Contentious Contract Provisions	
• Contract Approval Process	Each state has a slightly different process for contract approval.
• Level of Contract Simplification	Contracts are sophisticated contracts based on negotiations of several renewable energy and other contracts from PPAs.

Issue	Utility
	Southern California Edison
A. Energy Demand/Supply Planning	
• Basis for Planning	The California utilities have to file an Annual Procurement Plan focused on the annual Renewable Resource RFP/RFO to meet Renewable Portfolio Standard (RPS) requirements. The utilities are targeting a 33% RPS goal by 2020.
• Mechanism for determining issuance of RFP/CFT	SCE conducted renewable solicitations in 2002, 2003, 2005, 2006, 2007, 2008 and 2009. The 2010 solicitation is due out first quarter of 2010.
• Lead time for issuance of RFP	The California Public Utilities Commission (CPUC) must approve the Annual Procurement Plan. The annual Procurement Plan includes the RFP or Protocol documents, the Power Contracts, Transmission Ranking Report, Evaluation and Selection process, Previous year compliance plan. The RFP is issued within a few weeks of approval.
• Role of Stakeholders	Stakeholders can provide comments on the documents. In addition, the Procurement Review Group (PRG) for each utility is generally active in Procurement Plan comments and approvals.
• IRP Approval Process	The CPUC has to approve the Annual Procurement Plan before the solicitation can be issued.
• Other Planning Considerations	SCE has developed a Base Case and High Need Case of the renewable procurement initially required to meet the 20% RPS target by 2015. The base case assumes 100% delivery at the currently expected on-line dates of all executed contracts. The high need case assumes only 70% delivered energy from executed, but not yet delivering contracts. The High Need case is modeled to represent project development success rates as well as any contingency that would make meeting RPS goals less likely (e.g. delays due to transmission, material shortages, load growth beyond that which is forecasted, or less than expected output)
B. Sourcing and Procurement	
• Recent Solicitations	SCE has two groups within the Company to undertake different types of solicitations. The Renewable and Alternative Power group is responsible for undertaking the Renewable RFPs and Energy Supply and Management is responsible for all-source solicitations and gas contracts. From a renewables perspective, the following are the solicitation that are on-going or close to completion: • Renewable Standard Contract program 2010 – 250 MW for any eligible renewable resource up to 20 MW • Solar PV Program 2010 – 50 MW of roof-top or ground mounted projects over each of 5 years. Project size could be up to 10 MW. • 2009 Renewable RFP • CREST program – ongoing – Schedule CREST is for SCE retail customers who want to sell renewable energy to SCE from generators that do not exceed 1.5 MW – FIT program • Expression of Interest to sell RPS eligible biogas.
• Frequency of Solicitations	The annual solicitations have been issued on a regular basis since 2003. The 2010 RPS RFP is due out in the first quarter. The Solar PV program is a five year program although there is no set schedule when the RFO is issued.
• Solicitation Strategy	SCE is evolving its solicitation strategy to combine larger projects vetted through the annual solicitations with standard offer contracts and

	simplified procurement processes for smaller projects (less than 20 MW). While there is now a focus on project viability for the annual solicitation and larger more sophisticated contracts, the contracts for the smaller solicitations are viewed to be standard contracts with little or no negotiations.
• Time for Completing Solicitation	The annual solicitations can take an extreme amount of time when one considers the lengthy contract negotiation process. Bidders have 6 weeks to submit their proposals and SCE allots 4 weeks to conduct the evaluation and select the short list. However, contract negotiations can take 18 months to complete after short-list selection. The bidding process of SCE becomes a competitive negotiation process given the time to complete negotiations.
• Type of Solicitation	SCE issues RFPs and RFOs (Request for Offers)
• Stakeholder Involvement	All California utilities have a Procurement Review Group. The Procurement Review Group is comprised of non-bidding stakeholders such as environmental groups, TURN, Union of Concerned Scientists, Union interests, the Energy Division, etc. The members of the PRG provide input on procurement decisions and ask questions about the utility decisions.
• Interaction with Suppliers Throughout the Process	For the annual solicitation, most of the communications with suppliers occurs via the company website, until a short list is selected and contract negotiations begin. For the smaller solicitations communications between the utility project team and the bidders are extensive. As Independent Evaluator, Merrimack Energy was copied on all emails which easily exceeded 1000 emails during the process.
• Role of Utility Own Resources	For renewable resources, SCE has had affiliate bids from Edison Mission Energy but no self build. The Solar PV program has a component that allows for utility-owned generation of solar projects.
• Expected Trends in Procurement Process	SCE seems to be moving toward a portfolio of solicitations that include a full spectrum of opportunities for bidders. For example, bidders of projects 20 MW and less could bid into the RSC program or the annual solicitation or both.
• Unique Aspects of Solicitation Process	SCE has developed a mix of solicitations that allow a wide range of entities to compete across the size and technology spectrum.
• Use of Independent Evaluator/Fairness Advisor	IEs are required by Commission decisions and resolutions.
C. Interconnection	
• Interconnection Study Process	Applications for interconnection in California can be made either to the CAISO or host utility. A project's point of interconnection to the utility's electrical system determines to which entity the interconnection application is submitted. Interconnection directly to the CAISO controlled grid (primary voltages at or above 220kV) is processed by the CAISO under the CAISO tariff. Interconnection within a utility's distribution system is processed by the utility under the Wholesale Distribution Access Tariff. The original CAISO Large Generator Interconnection Process (LGIP) was developed according to FERC open access rules, which works on a "first-come first-serve" basis. When the project submitted an eligible application to interconnect, the project was assigned a queue position that defined when and how the project will be studied relative to the other applicants. However, the process has recently been redesigned due to the problems associated with a large queue and an extremely time

	consuming process to process the applications received. As a result, the LGIP was redesigned as a part of the Generation Interconnection Process Reform (GIPR). As a result, the LGIP process has been split into two tracks, based on the date of application for interconnection. If a project applied for interconnection prior to June 3, 2008, the triggered network upgrades are studied according to the previous serial queue process. If a project applied for interconnection on or after June 3, 2008, the projects are grouped by geographic location into clusters. Each cluster is now studied for a plan of service based on the type of interconnection requests received from interconnection customers.
• Time and Data Requirements for Completing Interconnection Studies	The new clustering study approach under the GIPR-revised LGIP moves away from the incremental system impact studies in favor of a full plan of service by geographical area. This GIPR process alleviates some of the risks inherent in the serial queue pertaining to project development and transmission lumpiness. The process calls for multiple studies of a collection, or cluster, of resources within a geographical region. At the end of a particular cluster study, the respective projects are required to commit the necessary funds to develop the network upgrades at the same time.
• Cost and Responsibility for Completing Studies	Under the cluster process, there are two open season application windows per year, which are open for 120 days each. The cost for applying for a study is $250,000.
• How are results of the Interconnection Study used in the Evaluation	Since transmission upgrade costs are included in the bid evaluation methodology, some methodology is required to estimate network upgrade costs. Further complicating the process is the fact that projects bidding into the RFP could be located within the host utility service area, in another utility service area, or outside the state. These factors have created significant problems for assessing transmission upgrade costs for each proposal. For resources that do not have an existing interconnection to the electric system or a completed facility study, system transmission upgrade costs are estimated using the utility's Transmission Ranking Cost Report (TRCR) methodology and specific details provided by Sellers in the RFP. Network upgrade costs and scope from interconnection studies are used to the extent they are available and applicable. Transmission cost adders for new generation are based on unit cost guides used in the interconnection cluster studies. Unit Cost guides for both SCE and PG&E are attached. The California utilities develop the TRCR each year for purposes of including the report in the RFP process. The purpose of the TRCR is to provide necessary cost information to be used solely for evaluating renewable resource bids so that the most cost-effective bids can be selected on a total cost basis. The TRCR is also designed to identify potential upgrade costs at key points on the transmission system to encourage bidders to minimize these costs in siting their projects.
• Unique Aspects of Interconnection and Transmission Analysis Process	There is a major issue in California associated with energy-only deliverability vs firm deliverability. Small Generators have been required to execute energy only interconnection studies. At the same time, utilities have been counting these projects toward Resource Adequacy (Capacity). Utilities are now saying that unless a generator has firm deliverability they will receive no capacity benefit.
• Areas for Improvement	N/A
• Other Issues	N/A
• Allocation of Interconnection and Transmission Costs	There are two types of interconnection costs defined. Direct Assignment Costs are the costs for interconnection and transmission facilities (excluding network upgrades) that are necessary to physically and electrically interconnect a generating facility to a transmission providers electric power grid at the point of interconnection. Sellers are responsible for all Direct Assignment Costs for interconnecting to the Transmission

	Provider. Seller's energy price bid should be based on the assumption that the Seller will bear the Direct Assignment Costs because there is no reimbursement of these costs to the Seller. Network Upgrade costs include the additions, modifications, and upgrades to a particular Transmission Provider's transmission system required at or beyond the Generating Facility's point of interconnection to accommodate the interconnection of the Generating Facility to the Transmission provider's system. With regard to the CAISO grid, the Seller is responsible for initially paying for Network Upgrades, unless a transmission provider under the jurisdiction of the CAISO elects to pre-fund the Network Upgrades and the pre-funding is approved by the CPUC. If not pre-funded, these costs are later reimbursed to the Seller pursuant to the CAISO tariff. Funds are repayed to the seller ithin 5 days of the generation facilities' initial operation, which reduces the cost burden on the interconnection customer. Therefore, network upgrade costs are an integral component in the utility's evaluation of proposals. For cost allocation purposes, under the cluster process, the following cost allocation principles apply: • Interconnection facilities costs and Distribution System Upgrade Costs are directly assigned to each customer, unless the facilities are shared; • Reliability network upgrade costs are allocated pro-rata based upon each project's maximum megawatt electrical output proposed; • Delivery network upgrade costs are allocated amonst all generators seeking full deliverability based upon load flow impacts as determined by the generation distribution factor methodology; • Projects not part of a cluster group are responsible for all upgrade costs that the project triggers.
D. Evaluation and Risk Allocation	
• Evaluation Process	Merrimack Energy has classified SCE's evaluation process as a competitive negotiations process. Once the bids are received they are evaluated based almost entirely on price and ranked based on the basis of the "Renewable Premium" value. Based on the Renewable Premium and the results of the Project Viability Calculator, SCE selects a short list. The short list is subject to approval by Internal Management (Risk Management Committee) and comments from the PRG (Procurement Review Group). Once the short list is selected, SCE then requests that selected bids sign an exclusivity agreement to negotiate the contract. Contract negotiations can take many months to complete. SCE and other California utilities also negotiate bilateral contracts with projects that did not bid or were proposed outside the bidding cycle. The bilateral contracts are subject to the same economic evaluation and it must be demonstrated that the bilateral offer would have been accepted to the short-list. For other RFOs, such as the Roof-top Solar PV or Renewable Standard Contract (RSC) program, SCE uses a primarily price-only process based on the levelized cost of the bid. Bidders may have to meet a minimum level of threshold criteria to compete.
• Evaluation Criteria (e.g.	Although the California Public Utilities Commission has developed a Project Viability Calculator as a means of evaluating bids from a non-

importance and weighting of price and non-price factors)	price or viability perspective for the 2009 RPS solicitations, SCE still ranks bids primarily on the price or "Renewable Premium" basis. The Viability Calculator developed by the Commission contains rankings and weights for certain criteria, which would allow the utilities to develop a non-price score for each proposal. In SCE's 2009 RFP, the utility, the Independent Evaluator and the bidder all scored the proposals using the Project Viability Calculator. However, SCE's approach was to only use the results of the Project Viability Calculator on the margin. That is, to either eliminate higher cost bid on the short list that may not be viable or to include bids on the short list that may have a higher price but would be considered highly viable.
• Transparency of Evaluation Criteria	The evaluation criteria, including a description of the bid evaluation methodology, are included in the RFP protocol documents. The bid forms are included on-line and can easily be accessed prior to submission of the proposal. Also, the Project Viability Calculator is available on the website along with the weights and criteria.
• Evaluation Methodology	For the 2009 Rewnewable RFP, SCE began using the Renewable Premium methodology as the primary evaluation metric to evaluate and rank proposals. The Renewable Premium is equal to the levelized cost minus the levelized benefits associated with each proposal in nominal $/MWh. For the quantitative analysis, benefits are comprised of separate capacity and energy components based on the calculated value of these products, while costs include the contract bid price, integration costs, transmission costs and debt equivalence. SCE relies upon the generation profile of the bid in its evaluation assessment. The objective of the quantitative assessment and relative rankings is to develop a preliminary short list that is further refined based on non-quantifiable attributes. The integration cost adder for purposes of conducting bid evaluation has been set at $0/MWh. For resources that do not have an existing interconnection to the electric system or a completed facility study, system transmission upgrade costs are estimated using SCE's Transmission Ranking Cost Report (TRCR) methodology and specific details provided by Sellers in the RFP. Network upgrade costs and scope from interconnection studies are used to the extent they are available and applicable. Transmission cost adders for new generation are based on unit cost guides used in the interconnection cluster studies.
• Are Model Contracts Included With the Solicitation Documents	Yes. The presence of the contracts is an important aspect of the protocol documents.
• Presence of Mandatory Provisions	The CPUC requires that all utilities include certain mandatory contract provisions in the pro forma contract. Initially there were approximately 12 mandatory provisions. Now there are about 4 mandatory provisions
• Role of Contract Negotiations	SCE's procurement process has been classified by Merrimack Energy as a competitive negotiation process. That is, bids are evaluated for purposes of selecting a short list. Once the short list is selected, SCE is free to begin negotiations with short listed bidders. Negotiations can take in excess of one year.
• Identification of Most Contentious Contract Provisions	The most contentious provisions in the contract include: o Curtailment provision o Security requirements o Permitting and interconnection provisions to allow for COD delay without damages o Guaranteed energy generation provisions
• Contract Approval Process	After a California utility executes a contract with a short listed bidder or bilateral contract outside the solicitation process, the utility files an Advice Letter application seeking approval of the contract. In the current regulatory environment, contract approval at the CPUC can take up to 12 months.

• Level of Contract Simplification	SCE has developed a standard contract for small renewable energy projects for both the Solar PV program as well as the Renewable Standard Contract program.
E. Contract Management	
• What Department Within the Utility Manages Power Contracts	Basically all contract management is done with Power Procurement. In RAP (Renewable Acquisition and Procurement), contract management and compliance report up through a senior manager. The contract group manages and monitor performance against the terms and makes sure they are enforcing their contract rights. The group is responsible for all contract amendments, letters, etc. They also perform some of the invoicing calculations in cooperation with the settlement group. Settlements (both bilateral and CAISO) are housed within a separate department, but within Power Procurement. They are responsible for all payment processing and invoice preparation. Risk (outside of PPBU) controls access to some of the contract setup aspects, but not for RAP at this time. When implementing their new system, risk will control access.
• Relationship to Energy Procurement Function	Contract management is closely linked to procurement.
• Major Issues Related to Contract Management	Transmission and permitting delays are probably the two most significant issues. Interpreting contract provisions when these delays are extended beyond an expected time frame creates tensions in the contracts depending how they are operating. For operating projects, changes in market design are typically the most challenging. This includes the introduction of the Market Redesign and Technology Upgrade (MRTU) as well as the introduction of new products/requirements (Renewable Energy Credits, Greenhouse Gas requirements, Standard Capacity Product, NERC requirements, Resource Adequacy, etc.)
• Lessons Learned Related to Contract Management	Try to collect feedback from a range of subject matter experts and incorporate that feedback into new agreements. Add provisions that make sure you have the ability to require the counterparty to comply with changing control area and regulatory provisions. Make sure you have adequate support for the law department and other subject matter experts to give you the best advice possible throughout the term of the agreement. If you can, build a portfolio of mostly shorter term contracts so that terms stay consistent with market status.
• Contract Management Tools or Procedures	According to a SCE spokesperson: *"One of our challenges is that we have a lot of growth and attrition for both contract managers and contract originators. We have to make sure we have recruiting efforts, on boarding and training processes and programs in place to support the constant need for qualified contracts staff. We have spent a lot of time to develop these programs and we have a lot more work to do. We are in the process of replacing our contract management system and trying to go through and document our processes and requirements to make sure the replacement system can meet our needs. Our contracts are much more complex and more detailed (and requiring detailed data) and therefore we need a system that can be adaptable as the market continues to evolve. Our contracting efforts are going to continue to grow and we need to become more efficient as well as be able to settle the terms as per the agreement in order to get full value out of the agreement."*

Issue	Utility
	Ontario Power Authority
A. Energy Demand/Supply Planning	
• Basis for Planning	In 2007, the OPA submitted a long-term plan, the Integrated Power System Plan (IPSP). While the regulatory review of the plan was not completed before being suspended in 2008, many of the elements of the plan have been implemented through directives of the Ministry of Energy. For example, by the end of 2010, the OPA will have more than 19,500 MW of new and existing supply under contract. Also, the Feed-in Tariff program has stimulated a renewable energy sector. The Ontario government is now looking to update the Plan. OPA will work with the government in this effort. OPA is also working closely with the Independent Electricity System Operator (IESO) and transmission and distribution companies in developing the IPSP.
• Mechanism for determining issuance of RFP/CFT	The IPSP contains a section on the Procurement Process which describes how the decisions are made to initiate a procurement process. The Procurement Process starts after the OPA has made its initial considerations and assessments whether to issue a solicitation. Prior to initiating the process the OPA will: • Identify the type, timing and location of resources that are capable of meeting the IPSP requirements; • Consider the factors identified in the IPSP regarding the advisability of entering into procurement contracts; and • In consultation with relevant interested parties, assess whether the identified resource requirements can be met through the capability of the IESO-administered markets or by other persons making investments independent of OPA procurements. There are two stages of the process. In the first stage, the OPA will select an appropriate procurement mechanism from among three main types: • Competitive procurement – in this process a value competition based upon price and/or qualitative criteria generally determines the selection of a project/program • Standard Offer Procurement – in this process pricing and resource type are standardized. Projects/programs that meet the requirements are paid the standardized price • Non-Competitive Procurement – this process takes the form of a direct negotiations with a proponent for the delivery of a specific project/program. The OPA's preferred procurement type, to the greatest extent possible, is competitive procurement. The second stage deals with the design and execution of the procurement types. Any of the procurement types may be preceded by registration and/or pre-qualification (RFI, RFQ, Request for Expression of Interest). The OPA can use any of the following competitive procurement options: (1) RFP; (2) CFT or (3) auction.
• Lead time for issuance of RFP	N/A

• Role of Stakeholders	Stakeholders may have input into the development of the IPSP. In addition, to select an appropriate type, the OPA has to gather information on the projects/programs that could meet the identified resource requirements. For these purposes, the OPA can use a variety of mechanisms including: (1) market scans and studies; (2) stakeholder engagement; (3) surveys; and (4) obtaining expert opinion.
• IRP Approval Process	Approval is requested from the Ontario Energy Board.
• Other Planning Considerations	OPA conducted several internal and external studies in 2005 after undertaking a few procurement processes. OPA concluded that competitive procurements would be the default process. Some of the key findings of these assessments included: • Homogeneous competitions are preferable, meaning that having similar projects compete is better than having a variety of project types (i.e. supply and conservation; renewables and gas-fired generation) compete • Targeted procurements that outline clear requirements for the specific resource will result in a fair procurement with a good result. Where a very specific need has been identified, the procurement should outline those specific requirements. • The procurement, in particular the requirements and evaluation criteria, should lead to a robust competition with qualified proponents. • The OPA has to provide sufficient channels to allow proponents to communicate with the OPA to provide input and ask questions. All proponents must have equal and fair access to these channels.
B. Sourcing and Procurement	
• Recent Solicitations	OPA has conducted a range of procurement processes including Combined Heat and Power, 3 Renewable RFPs; several conventional RFPs for Southwest Greater Toronto area, Greater Toronto area west, York Region Demand Response, and an RFP for St. Mary's Paper Corp. The main procurement process is the Feed-in Tariff program which is targeting 6,600 MW of eligible renewable resources over the next 3 years. The Feed-in Tariff program has two components: (1) FIT Program for projects over 10 kW and (2) micro-FIT for projects 10 kW or less. To date there have been 1,270 contracts executed.
• Frequency of Solicitations	The frequency of solicitations varies. It appears that the timing of the solicitations is based on a directive from the Government. The three-year Business Plan for 2011-2013 is only focused on the Feed-in Tariff program.
• Solicitation Strategy	OPA's procurement strategy is based on a multi-step process to identify the type of procurement requested and then select the appropriate process and design to meet the requirements.
• Time for Completing Solicitation	The RES III RFP draft RFP was issued in June 2008; proposals were due on October 30, 2008; and completion of evaluation was scheduled for December 2008.
• Type of Solicitation	Solicitations can either be RFPs, CFTs, or auction. OPA appears to favor RFPs based on their flexibility.
• Stakeholder Involvement	The OPA is developing a rigorous stakeholder engagement process based on the principles of relevance, inclusiveness, accessibility, transparency, and contribution. The traditional practice of stakeholder consultation commonly involves consulting with industry participants that typically follow regulatory proceedings as intervenors. These parties are generally other energy companies, energy-related associations,

	various other industry and consumer associations, and special interest groups such as environmental and social advocacy alliances. Such stakeholders are highly knowledgeable about industry issues and participate actively in regulatory and other industry initiatives. In order to enhance inclusive stakeholdering for the purpose of informing the numerous corporate and government-mandated initiatives, OPA is building on the strengths of traditional stakeholder practices and expanding the process to include a multi-channel engagement plan which extends the traditional foundation with a breadth of views and opinions from non-electricity industry parties including the consumer.
• Interaction with Suppliers Throughout the Process	OPA appears to focus on close engagement with suppliers throughout the procurement process based on its statements and objectives.
• Role of Utility Own Resources	No utility resources are bid.
• Expected Trends in Procurement Process	In addition to the major initiative toward a Feed-in Tariff program, recent procurements involve solicitations on behalf of specific customers as well as bilateral negotiations. OPA is also one of the few utilities that have targeted such resources as combined heat and power options as well as demand response programs and DSM. According OPA's 2010 Business Plan, the introduction of the Feed-in Tariff program in 2009 has changed the way OPA procures and contracts for renewable energy. With this development, the organization is moving away from designing and executing discrete procurements with a known outcome to administering and managing an ongoing program with variable uptake.
• Unique Aspects of Solicitation Process	OPA has developed a range of procurement options, many of which are unique in the industry. Each registered participant is entitled to one private individual information session with OPA for a maximum of one hour prior to submission of proposals.
• Use of Independent Evaluator/Fairness Advisor	OPA uses a Fairness Advisor for its procurement processes.
C. Interconnection	
• Transmission Screening Process	Since OPA is a separate entity from any Transmission Provider in Ontario, OPA had to develop a process for conducting a transmission review of each proposal. According to OPA, Transmission Screening is necessary because available transmission and capacity on the existing Transmission System is limited in certain parts of the Province. The OPA will select proposals that have the lowest Evaluated Proposal Price and in the aggregate, have Contract Capacities that do not exceed the applicable transmission limits. This will ensure continued reliable system operation and provide a reasonable assurance that significant Transmission System upgrade costs will not be necessary. The Transmission Screen has 3 separate stages: the Restricted circuit screen, the Zone screen and the Area screen. The estimate of the limits, as outlined in Appendix Q, is for evaluation purposes only pursuant to this RES III RFP. Proponents should not rely upon Restricted Circuit Limits, Zone Limits and Area Limits as definitive of the actual transmission restrictions and limits that may be applicable to any

	proposal. A proponent should check with the IESO or the Transmitter to determine specific transmission restrictions for its proposed Contract Facility. Proposed Contract Facilities with Connection points located within a Restricted Circuit will be subject to an initial screening. Proposed Contract Facilities within each Restricted Circuit will be ranked in ascending order of Evaluated Proposal Price, and the Proposals with the lowest Evaluated Proposal Prices up to the specified limit will continue to be evaluated. This reserved right can be applied for one or more restricted Circuits at the OPA's sole discretion. All other proposals will be rejected. All proposals that have a Connection Point that is not located on a specified Restricted Circuit, as outlined in Appendix Q, will be subject to a general screen to ensure the general limits are met. Following the completion of the Restricted Circuit screen, all proposals that have passed the Restricted Circuit Screen will be screened by Zone. Proposals within each Zone will be ranked in ascending order of the Evaluated Proposal Price, and the proposed Contract Facilities with the lowest Evaluated Proposal Prices up to the specified limit will continue to be evaluated. This reserved right can be applied for one or more Zones at the OPA's sole discretion. All other proposals will be rejected. Following the completion of the Zone screen, all proposals that have passed the Zone screen will be screened by Area. Proposals within each Area will be ranked in ascending order of the Evaluated Proposal Price, and the proposals with the lowest Evaluated Proposal Prices up to the specified limit will continue to be evaluated. The OPA reserves the right to allow the Marginal Proposal to continue to be evaluated. This reserved right can be applied for one or more Areas at the OPA's sole discretion. All other proposals will be rejected.
D. Evaluation and Risk Allocation	Based on Renewable RFP III – June 2008 On November 20, 2007, the OPA issued an RES Phase III Request for Expressions of Interest, which was the first step in fulfilling the directive from the Ministry of Energy to procure up to 2,000 MW of new renewable energy supply from projects greater than 10 MW in size. This Directive required that the OPA commence consultations on the design of the first procurement for 500 MW of new renewable energy supply by the end of 2007.
• Evaluation Process	OPA uses a 4-stage evaluation process: • Stage 1 – Proposal Completeness Requirements – in this stage each proposal will pass or fail depending on whether the proposal meets all of the completeness requirements identified. • Stage 2 – Mandatory Requirements – In this stage each proposal will pass or fail depending on whether the proposal meets each of the mandatory requirements • Stage 3 – Rated Criteria – In this stage each proposal that passes Stage 2 will be awarded a point score up to a maximum of 100 points. A bidder must achieve a minimum score of 40 total points. • Stage 4 – Evaluation and Selection – In this stage each proposal that passes Stage 3 will have its Proposal Price Statement opened and evaluated. The Proposal Price will be discounted by a factor based on the Proposal's total point score in Stage 3 to determine the Proposal's Evaluated Proposal Price. The Evaluated Proposal Price will then be used to select the most competitive proposals according to the methodology set out in the RFP.

• Evaluation Criteria (e.g. importance and weighting of price and non-price factors)	The evaluation criteria and the maximum point scores for each category as identified in the RFP are provided below: • Environmental Assessment – 20 points • Municipal and Regional Zoning Approvals – 20 points • Equipment Availability – 15 points • Resource Availability Data – 10 points • Proponent Team Experience – 10 points • Financial Assessment – 25 points The RFP also defines how bidders could achieve high, medium, or low points in each category.
• Transparency of Evaluation Criteria	The RFP includes high level non-price weights but not specific sub-criteria weights.
• Evaluation Methodology	Once the Evaluated Proposal Price is calculated, OPA will evaluate each proposal relative to Transmission Screens. Following completion of the Transmission Screens, the remaining proposals will be progressively selected for inclusion in the initial stack from the lowest to highest evaluated proposal price such that the cumulative Contract Capacities of the selected proposals up to 750 MW. The OPA reserves the right to include the Marginal Proposals in the Initial Stack. In the event that the combined total Contract Capacity of all Proposals that have passed the Transmission Screen is less than 750 MW, all such proposals will be selected for inclusion in the Initial Stack. The OPA will establish a Price Threshold in order to select Proposals for inclusion in the Final Stack. The Price Threshold will be 115% of the weighted average Evaluated Proposal Price of all Proposals in the initial stack excluding the Proposals with the highest Evaluated Proposal Price. If the proposal with the highest Evaluated Proposal Price is more than the Price Threshold, then the OPA may reject such proposal.
• Are Model Contracts Included With the Solicitation Documents	Yes
• Presence of Mandatory Provisions	N/A
• Role of Contract Negotiations	All selected proponents shall sign the RES III contract in the form circulated by the OPA within 10 days of being awarded a contract and shall deliver such other closing documents as the OPA requests.
• Identification of Most Contentious Contract Provisions	N/A
• Contract Approval Process	N/A
• Level of Contract Simplification	N/A

APPENDIX D

Respondent Comments on BC Hydro Energy Procurement Practices

This Appendix D contains the comments received by Merrimack Energy from IPPs, other stakeholders and First Nations in a form as close to verbatim as reasonably possible. Merrimack has made no effort to recast the comments and has only grouped them by relevant functional area.

1. <u>Energy Demand/Supply Planning</u>

- The IRP should play a very important role in shaping BC Hydro's energy procurement. Support the notion of an IRP that is consistent with government policies and continuing to be the basis on which power calls are based.
- The IRP should affect the timing and amount of Calls under all reasonable circumstances. We do not see any notable circumstances that would warrant overlooking the results of the IRP.
- IRP process should be similar to the role of BC Hydro's LTAP process, i.e. propose a plan, including resource requirements and schedule, to be subject to review and confirmation of need. Also, the basic parameters for acquiring power should be reviewed, including screening for risk and other factors.
- The IRP and energy procurement process should be linked.
- The IRP should be used to help identify the amount of energy to be acquired. However, the timing between IRPs is too prolonged. Each IRP should be used to provide the industry with sufficient signals to help identify when power calls will occur to help industry players plan better. Interim supply and demand updates should be provided and used to identify the timing of future power calls.
- The IRP should determine the amount of power to be acquired and the timing.
- The timing of need is most important for suppliers.
- It is expected there will be a transmission plan associated with the IRP.
- Some question the role of DSM and conservation in demand/supply planning process.
- Demand forecast is a major issue. Some feel Hydro is understating the demand forecast because the impacts of conservation are overstated and demand from new applications will return demand to the historical growth rate net of conservation. Others feel that the doubling of rates will cause a price-induced drop in demand.
- The IRP should identify opportunities for procurement; provide consistent and regular timing for procurement and identify the timing for interconnection and transmission to new resources that will meet the procurement plan.
- The IRP and procurement activity should be linked.

- The IRP should define energy and capacity required, and work within government policy. The IRP should be visionary and proactive.
- The IRP should consider both domestic and foreign supply and demand; IRP should include the outlook for exporting long-term firm electricity and how new generation for export markets affects the domestic market.
- The CEA made a mistake by removing the IRP from BCUC review during which the allocation of resources between BC Hydro and third parties can be scrutinized with normal cross examination.
- The CEA allocated resources to BC Hydro and to IPPs, but the allocation is not based on cost effectiveness and competition and would be more economic if allowed to be competitive.
- BC Hydro appears to apply creative accounting as to how to price their own projects. For example, Site C costs don't seem to incorporate a new 500 kV line to the lower mainland.
- Pre-building to transmission zones will be considered as a part of the IRP but the likelihood of such investments being cost-justified based on the uncertainty of future projects seems low.
- The IRP is a planning process for BC Hydro so it will obviously be linked to procurement. However, the IRP needs to be a legitimate process that actually looks at the real cost of DSM and the real cost of major projects like Site C. If the IRP process does not include those inputs then it will be of limited value. The IRP and procurement do not need to be formally linked. For example, if early indications support more power purchases then BC Hydro should proceed with a Clean Call prior to the IRP being completed.
- The IRP should not be constrained by the CEA and should investigate whether the allocation of resources between BC Hydro and third parties is justified by costs.
- Government policy that requires BC Hydro to procure more power than they need is crazy.
- No procurement is good procurement except to fill valleys.
- If BC Hydro doesn't like the prices it should not buy anything.
- A policy question is raised about the value proposition of buying more green energy at relatively high incremental prices for a system which is overwhelmingly "green" already. This is not like US systems with huge GHG emissions that are forcing "high price" GHG reductions on the system. The value of the diminishing returns is a legitimate inquiry for the BC ratepaying public.
- IRP should be used to identify opportunities for procurement.
- The CEA was not thought out well on the opportunities for developing an export market. The CEA export provisions describe "pie in the sky" and disable BC Hydro from making any financial commitments to export investment.
- Other large utilities are shying away from BC Hydro in export planning since BC Hydro cannot make funding commitments.

- There is no realistic business plan or model which supports the development of an export market: the CEA appears to be based on the unrealistic expectation that export market buyers in the US will directly or indirectly (by regulatory mandate or the like) support large transmission investment by US utilities or institutional equity investors in order to procure green Canadian power in preference to green US power.
- We have confidence in BC Hydro's load forecasting methodology.
- Favors over-procurement as a substitute for fossil fuel.
- The current supply and demand projections are likely to show only the need for a single procurement in 2015/2016 to fill the need for the Assurance 3,000 GWh by 2020.
- The IRP should provide input to the annual growth in the supply/demand gap so that the quantity of procurement requirements per year can be determined.
- The procurement process should follow upon the conclusion of the IRP.
- The IRP is a comprehensive plan. By definition it should provide the basis for justifying any resource acquisition. However, if the load/resource balance is veering off-track to the extent that requirements or targets of the Clean Energy Act or Special Directions are at risk, we feel BC Hydro should issue a Call even prior to the government approving an IRP.

2. <u>Sourcing and Procurement</u>

- RFP process is preferable to the Call for Tenders process. CFTs are rigid with no room for negotiations. Also, the time to close is too long and expensive which increases bid prices unnecessarily. An RFP process in general is a better form of procurement.
- BC Hydro's current procurement approach is large, province-wide, open to all renewable technologies provided that meet the Clean guidelines published by the Province. I believe the procurement will benefit from processes that are targeted (technology/region/product specific), smaller, but more frequent. This requires the IRP to provide guidance not only on the timing and volume of supply gaps but also the location and types of supply gaps.
- Individuals at BC Hydro involved in the procurement process were very good to work with.
- BC Hydro's process is fair in that BC Hydro follows the rules that were laid out, but the rules may not always be fair.
- BC Hydro is open in how it will conduct the process prior to it commencing, but once the process is underway, it is not open.
- The Clean Power Call was not very transparent in how various value-added offers would be evaluated. Further, after the process is commenced, it is not transparent in how decisions are made even in the evaluation report.
- We prefer a process that differentiates between larger and smaller projects
- It is not clear how BC Hydro evaluates the bids received. BC Hydro needs to be clearer on identifying the criteria to apply in the evaluation.

- BC Hydro debriefed the supplier after the process was completed and provided reasonable information.
- The workshops offered were very helpful in understanding the process and requirements.
- Everyone supplier is treated the same in the process.
- The information provided in the Call documents is adequate to submit a good bid.
- There is uncertainty regarding the basis for including losses in the evaluation and the methodology used to calculate losses. Their argument is that power put into the grid will be used locally and benefit BC Hydro. Why should losses be added to the evaluation?
- Suppliers want to know more about how the bid evaluation process is undertaken.
- More transparency will be well received.
- The procurement process is not overly complex.
- The seller has never found BC Hydro's process to be onerous.
- The fact that the procurement process was comprehensive helped in the financing of the project.
- There are a lot of neophyte developers in British Columbia, particularly with respect to First Nations' consultation and fisheries issues.
- BC Hydro's evaluation methodology only compares firm energy price not non-firm energy. The supplier felt this created a bias against hydro.
- The evaluation and presentation of data should be based on average price not firm seasonal price.
- The cost for permitting a project is significant. The supplier would not undertake this level of development effort unless there is a regular and predictable Call process.
- Attrition reflects in part the state of readiness of bids which were not worked on far enough in advance of the uncertain and unpredictable calls to be mature. This results in permit, equipment supply, First Nations and other problems not be discovered until after the bids are in.
- Often projects are chosen by BC Hydro from developers who are never going to get financing. Many entities with contracts are not bankable.
- Attrition rates are high because BC Hydro's process is a price-driven process. From a financing standpoint, project viability is very important.
- Suggestion for a pre-qualification process for larger solicitations.
- Workshops are very helpful for understanding the process.
- The supplier was not happy with modifications that took place during the procurement process such as Dokie Wind. Once you start the process no modifications. Bidders who bid low were very upset.
- Overall, BC Hydro gets high grades for their process. Good job in procuring power.
- BC Hydro should issue more frequent Calls. For large Calls, three years elapsed between each of the 2003, F2006, and 2008 Calls. Bi-annual Calls are

better for IPP suppliers, permitting, and approvals agencies and BC Hydro procurement staffing.

- For the Standing Offer Program (SOP) update pricing every two years, rather than every three years.
- BC Hydro should set dates for future Calls and SOP updates far in advance and try to stick to those dates.
- For large project Calls, make the target procurement amount large enough to attract enough good bidders, but not so large that it will cause a boom-bust cycle as projects continue through the permitting, construction, and bonding steps.
- Reduce the time from bid receipt – to award – to section 71 approval to reduce bidders having to include contingencies for potential big swings in interest rates or for cost escalation of materials or payment of major equipment holding fees.
- BC Hydro should raise the minimum threshold for Call eligibility to require projects to have virtually all their major permits and key agreements prior to submitting their bids.
- The higher eligibility requirements that BC Hydro uses for its Standing Offer Program should be applied to other Calls.
- The Call asks for the lender to support the bid along with an equity guarantee. No one would really provide this. Bidders got letters that had no teeth or value.
- Price is the primary driver of selection not project viability and some bidders complain that the neophyte bidders drive the realistic bidders out of the market by bidding unrealistically low prices.
- Some bidders claim that pricing should be secondary if need exists, but these claims do not take the uncertainty of need, the duty of BC Hydro to ratepayers and to the Commission and the evidence from other jurisdictions into account.
- The procurement process is not transparent.
- Many developers complain about lack of openness and transparency, but I don't think they appreciate that what they want is to see is commercially sensitive information. Many of the sources of lack of transparency are outside of BCH's control, such as government policies, etc.
- Once the contract is signed, no dialogue about progression of project.
- No evidence BC Hydro uses any other criteria besides price in the evaluation.
- Need to initiate dialogue to create the best structured product for wind and hydro. Now, one size fits all.
- Pricing methodology forces sellers to offer much higher prices for seasonal firm power than they should
- BC Hydro staff has been good in addressing specific problems faced by suppliers.
- Although suppliers may want more emphasis on project viability, the Commission is focused on price.
- BC Hydro's bid selection and evaluation criteria should be clearer. They should publish the list of criteria and show an explicit weighting for each

criteria. Evaluation formula should be algorithmic. Pronounce the weighting. Avoid subjective elements. Once bids are submitted BC Hydro's evaluation process appears to work well.

- Comparison to other resources is very important. Use fully costed risk-adjusted comparisons. A clearly level playing field is especially important as BC Hydro acquires energy from its own generating arm as well as IPPs. Clearer evaluation criteria would reduce IPPs suspicion of BC Hydro procurement arm favoring another arm of BC Hydro which will turn off investment in BC IPPs.
- Attrition rate is affected by the uncertainty when the next call will be issued.
- Favors process of having specific criteria for evaluation. In this way they would know what they need to do to compete. Frustrated that low quality projects are selected.
- The strengths of BC Hydro's process include: (1) worked effectively with suppliers and intervener groups to design calls; (2) procurement deals with a broad spectrum of factors. Weaknesses include: (1) timeliness of the process.
- BC Hydro should report only average prices.
- For the Integrated Power Offer (IPO), BC Hydro involved stakeholders very early in the process. Workshops with stakeholders were informative and valuable. BC Hydro did a great job of stakeholder engagement in the IPO.
- Initiative of BC Hydro in the IPO to meet with bidders to describe their projects before submission of the proposals was very useful.
- BC Hydro focuses on the lowest price and does not give adequate weight to viability of the bidders.
- BC Hydro ran its Bio-Energy Call very professionally. The project team at BC Hydro attempted to put together the best process possible. BC Hydro was fair and forthcoming in implementing the process.
- BC Hydro team lacked experience with biomass-fired power plants. The team did, not show understanding how biomass markets change with paper and construction industry cycles and how prices in the market are set.
- BC Hydro has not pursued energy sector diversity as much as it should to enhance the security and reliability of BC's electricity sector. Some renewable resources, such as geothermal, are not able to effectively compete within BC Hydro's procurement processes.
- BC Hydro should design and launch separate procurement processes for renewable resource options, including geothermal. The procurement should set a target for geothermal and allow competition until the block has been filled.
- The FIT program targets high cost emerging technologies, while existing technologies such as geothermal are lower cost options.
- Small IPPs will not survive with only a single call in the next 10 years.
- The current number of small IPPs will die before the next call and be replaced with a new crop of small IPPs which will be neophytes who again underbid the realistic bidders.

- Large skilled bidders are leaving BC and will not return since the calls have favored the selection of unskilled neophytes.
- Regular recurring calls for power will lead to greater investment in resource exploration and development – for example, conduct procurement calls every two years for 2,000 GWh per call.
- A more pragmatic outcome might be for BCH to issue smaller and more frequent calls for power so that both the attrition from prior calls and the supply/demand gap can be more continually updated.
- I am generally pleased with the entire procurement and discussions with BCH through the process.
- The problem is with the fairly open-ended completion date which makes it hard to continue resourcing projects for up to two years following call issuance before the process is concluded.
- The negotiated settlement process where BCH provides developers with some sense of the price range necessary to be competitive to get a PPA creates the optics of reducing the potential procurement prices from developers but is more likely to lead to those projects becoming future sources of attrition.
- The change within the Call process to RFP/negotiations from the CFT is a good one.

3. **<u>Project Interconnection</u>**

- Cost estimates in feasibility studies are high level and costs can be quite a bit different from the estimates. This was a major issue in the 2006 Call.
- The issue of concern to IPPs is the impact of cost of interconnection and transmission on the bid evaluation and ranking. No idea what the impact will be on their competitive cost position.
- BC Hydro has generally managed to build interconnection facilities on time for bidders to meet their Commercial Operation Date (COD) but it has been a challenge.
- The transmission and distribution system will be stressed since the 2008 Clean Call will use up a lot of capacity. After these projects are interconnected, future expansions will add costs and delay to future projects.
- Delays in completing interconnection and transmission facilities increase the carrying costs to the supplier.
- BC Hydro has encouraged suppliers to request their interconnection studies before they submit a bid.
- The entire interconnection process has to be revisited.
- The transmission adders for projects in clusters are overpriced relative to projects outside of clusters.
- Adders which consider all projects as transmitting to the Lower Mainland may not be justified for certain locations.
- While BC Hydro absorbs the cost of transmission system expansion to support projects, a higher actual cost of transmission upgrades would increase the amount of security required and thus the cost to the supplier.

- Some bidders would like to know the transmission adders which affect the evaluation of their projects before they bid, but BC Hydro thinks that it may benefit from such blind bidding.
- Current effort to integrate BCTC into BC Hydro and align interconnection will go a long ways to improve the process.
- An internal issue at BC Hydro is the availability of resources to perform the interconnection studies on time.
- BC Hydro is developing different processes for distribution and transmission level interconnections.
- Bidders may be hesitant to request interconnection studies before they submit a proposal because the request would be posted and their intent would be public.
- BC Hydro is focusing on providing more information about the transmission and distribution system upfront to suppliers.
- Data forms may be onerous at the feasibility stage. BC Hydro should just ask for generic data not generator specific data at this point. It is too early in the process for the bidder to identify its project specific information.
- Interconnection costs have too frequently changed after the EPA was signed, which means after the projects' revenues have been fixed. This can be a big risk for the IPP. It caused some projects to be attrition statistics in the past. Interconnection costs should either be a) fixed at the time of bidding, or b) revenues should be scalable depending on actual direct interconnection costs.
- BC Hydro should also allow developers to perform the interconnection work themselves as long as they are built in accordance with BC Hydro specifications and inspection.
- Planning culture at BC Hydro has been focused on not accepting risk.
- BCTC wanted hard data on a specific generator/turbine. However, you can't get the data from the suppliers until you agree to purchase equipment. Can't do the study until you buy the generator. As a result, the supplier is getting vague numbers upfront. There must be a better way of getting good estimates. This adds uncertainty to the process especially for small generators.
- BCTC/BC Hydro interconnection process was a brutal process. BCTC couldn't tell the suppliers when the network upgrades would be completed and how much they would cost. This created a problem for lenders. The recent contract addresses this but previous contracts put onus on the seller. Bidders would prefer to know the network upgrade penalty put on a bid before the bid is submitted.
- There is need for suppliers to get their feasibility studies done first before they submit a bid.
- Having BCTC under BC Hydro is a major benefit.
- Transmission and distribution connected projects are currently treated differently (how costs are allocated between the utility and IPPs). They should be aligned to be consistent.
- BC Hydro's estimation process and assumptions used need to be transparent and defensible.

- BC Hydro is perceived to insist on “gold-plated” standards at higher costs, at the expense of IPPs.
- Turn-around time for studies needs to be improved.
- We did not know the results of the interconnection study prior to submitting our bid so this seriously disadvantaged our ability to succeed. Also, we were allowed to submit an interconnection request and spend $30,000 when BCTC and BC Hydro effectively knew there was no way they would allow the interconnection scenario we proposed. These facts, along with the refusal to discuss the situation with us after numerous attempts to have a dialogue, led to serious frustration and a belief that BC Hydro and BCTC really did not have any desire to actually see IPPs succeed.
- In spite of our Project paying BCTC three individual payments of $25,000 each for guidance on interconnection parameters including interconnection point, and costs, we received no response excepting for one response which directed us to interconnect to a completely different and opposite direction from the previous advice. On the last day before the deadline to submit our proposal to BC Hydro, BCTC informed us that the interconnection cost went from approximately $500,000 (as determined by our Consulting Engineer) to a new sum of $7,600,000. This resulted in our proposal price being slightly “too high”. All of this happened without any notice or contact from BC Hydro.
- The Interconnection Department’s productivity is poor; efficiency and level of competence in project management is poor. The organizational structure and reporting is dysfunctional and there is no accountability for interconnection costs and budgets.
- Where there is a large number of smallish projects in a remote area that are being developed by several developers, a process needs to be created that delivers the right sized transmission line for the medium/long-term without delaying or overly burdening the project(s) that are ready the soonest. The process for wisely interconnecting these clusters of projects must be established and address sharing, cost allocation, and timing.
- BC Hydro’s letter supported maintaining the traditional wait-until-the-EPA-is-signed approach for connecting IPPs to the grid. But, since securing rights of way and building transmission can take a long time, a process needs to be determined to ensure the wires will be ready for the generators to plug into.
- This reactive approach, whereby each expansion is based on a one-off, EPA-by-EPA trigger, will drive up connection prices and cost ratpayers much more in the long run. This is counter to Energy Plan Policy Action #17 which urges “investment in upgrading ….. transmission lines to retain ongoing competitive advantage”.
- To ensure transmission capacity is in place when needed, BCTC should move beyond the contract driven approach to an approach that builds infrastructure in advance of need … based in part on its own assessment of future market needs. We believe BC Hydro should move towards a more proactive approach to transmission expansion, rather than the traditional reactive approach.

- Transmission interconnection costs are open ended and BCH is unwilling to stand behind their estimates which developers rely upon for EPA bids.
- BC Hydro should submit a BCUC Application to replace the CEAP/OATT with a simpler process that takes care of the engineering and cost estimation more fully, earlier in the process.
- A regional approach like Ontario or Texas is needed.
- There needs to be (the government should make it happen) a long-term bulk transmission plan consistent with meeting clean energy targets in an orderly fashion. Otherwise, major transmission investments will continue (ref NWTL) to be made on a political, rather than economic basis.

4. Evaluation and Risk Allocation

- BC Hydro should reconsider the adder to the bid evaluation associated with delivering power to the lower mainland especially given that load is growing in other areas and locating projects in those areas are in the best interest of the system. From an economic development standpoint this practice could discourage development. One option could be to do an adder by region or treat as a non-price factor.
- The EPA as it now stands is financeable but it still needlessly puts risk onto the proponents that need to be priced in.
- Major risks include change of law risk, flow through on taxes, and 5 year ratchet.
- There is an issue with the firm versus non-firm pricing mechanism. Liquidated damage provisions are onerous if firm nominations are set too high. If too low, the seller loses revenues. This is not a risk that should be placed on the IPP. BC Hydro should be able to absorb this risk given its hydro system.
- If there were no Liquidated Damage and other penalty provisions, it is estimated that the bid price would be 10-20% lower.
- BC Hydro believes that the Liquidated Damages are very low ($5/MWh) and that the non-Firm price is still a market-based price which is needed to hold BC Hydro's ratepayers harmless.
- The firm energy risk allocation should be re-considered. It was appropriate when firm sources of energy participated (coal, gas, biomass) in open calls, but when only intermittent resources participate, then calls should be designed to reflect the characteristics of the types of resources participating.
- BC Hydro's evaluation of the wind adder is flawed and disadvantages wind relative to other resources. The wind adder in the 2008 CPC was $10 of which $5 was allocated to integration costs and $5 was allocated to energy shift costs. The cost associated with integration is valid. However, the costs associated with energy shift are not because BC Hydro requested firm energy. BC Hydro did not have a preference for when the firm energy delivered was within the season as long as the total firm energy amount was delivered during the season; otherwise liquidated damages would have to be paid. The energy shift cost was based on the hour to hour or day to day economic loss associated with BC Hydro acquiring wind energy. This contradicts the

seasonal firm energy requirement and since it was only applied to wind projects, it prejudiced wind projects.

- The flow through of costs such as fibre costs, property taxes, water rights, and change in law has been a major issue. Suppliers feel some of these costs are out of their control and should be passed through; other suppliers think that IPPs were hired to take and price these risks, but the latter suppliers admit that the number of bidders will increase if flow through is allowed.
- BC Hydro believes in most cases that costs which are candidates for flow through are better managed by IPPs than by BC Hydro but recognizes in some cases, such as fibre costs, that cost management is difficult for all involved.
- Water rental rates that follow the very large BC Hydo rate increases over the next 10 to 30 years should be looked at again in light of the pricing needed to absorb these risks.
- Some flow through issues should be re-visited to see what the value proposition is: that is, are the premiums added to prices worth more or less than the risk being absorbed by the bidders? The Ministry has commented that studies of the value proposition probably are a good idea.
- The 5 year reset is a major issue, described by some as “draconian” and “grossly unfair” in light of its asymmetry limiting upside adjustments to 110%.
- There are a number of requirements associated with the letter of credit.
- The EPA is a long and complex document.
- Other bidders found the EPA to be characteristic of such energy contracts and manageable with the assistance of good lawyers.
- Negotiations on the contract were very responsive and timely.
- Original EPA contained a number of cross references that created confusion at the beginning of the procurement process but BC Hydro rectified the problems as the process evolved.
- There have been a number of project failures because BC Hydro has selected a large number of small projects.
- The asymmetric risk for pricing and output guarantees is unfair and weighted in one direction. This increases price significantly.
- BC Hydro’s process has been moving toward more flexibility in contract negotiations.
- Certain bidders said that it is not a problem for a supplier to absorb a pass through. That is why there is an IPP industry. Managing that risk is the function of the IPP, although it would be nice to have some caps. These bidders also admitted that with fewer risks, more competition would exist.
- The 2008 EPA is a workable contract but what is missing is the ability to sit down and come up with tailored terms.
- Some doubts remain about the provisions dealing with First Nations’ risk and further inquiry is appropriate to determine whether financing is made more difficult with current terms.
- First Nations risk that relates to permits that Sellers must obtain should not be transferred to BC Hydro which is less able to manage the consultation and

accommodation risk for permits. Successful resolution with First Nations may be impeded if BC Hydro is seen as allowing added time or the flow through of costs for First Nations' accommodation of permit duties of consultation.

- Prefers bilateral negotiations.
- Hydro is penalized in pricing regime which limits Seasonally Firm Energy in freshet period and imposes asymmetric five-year adjustments to allowed amount of firm energy.
- Wind integration adder of $10/MWh is not imposed on hydro and balances some of the hydro disadvantages.
- Contracts are at least as good as in most jurisdictions and better than in most jurisdictions.
- BC Hydro's EPAs in general do not provide an appropriate balance of risk between the utility and supplier. BC Hydro puts unnecessary risk on the developer. For example in the 2008 Clean Call included the following provisions:
    - The residual ownership issue caused huge issues with First Nations regarding IBAs that may leave them with the assets at the end of the project life. Financiers had a difficult time with this issue. No other jurisdiction has such a provision.
    - Everyone recognizes that environmental attributes have a future value. The risk of pricing such a value into a bid price might move a project outside the contract field, thus, EA pricing is zero. Developers take all the risk and BC Hydro gets the future value for zero dollars.
        - i. This provision forces the bidder to value such attributes without a commonly accepted criterion for valuation. Thus, the bidder could lose or win a contract as a result of perception as opposed to fundamental economic criteria and if the value of the green attributes is buried in the price, no one will be able to see the actual cost of energy, to compare it with past calls or other alternatives.
        - ii. Green attributes are designed to encourage investment in the renewable energy industry with the purpose of supporting the reduction of GHG emissions. Such attributes do not have to accompany the electrons produced, and in fact should be used to re-invest in other projects that displace GHG emissions. Given their purpose, they have value. Exactly what value is depends on a market that has yet to be developed.
        - iii. This clouds the true cost of electricity and raises concern over who should be benefiting from any upside realized down the road from such attributes.
    - For wind projects, BC Hydro priced a $10/MWh integration charge, one of the highest in North America, in a Province that has the least expensive power. The developer risks losing a contract because a non-justified price on integration is attached.

- For wind, no other jurisdiction sets price based on seasons. Rather, they use a full year. The risk is that the wind developer will have a bad season and pay liquidated damages. BC Hydro simply purchases power elsewhere.
    - A 5 year ratchet clause can lower the contract firm energy commitment for the next 5 years. This can reduce revenues significantly. Why this clause is even there is a mystery, but it hugely unbalances the risk between BC Hydro and an IPP.
    - No flow-throughs for extra-ordinary tax increases is a major issue. BC Hydro simply passes on such increases to ratepayers, but IPPs have to eat it.
- Regulatory approval process has been a long process.
- BC Hydro's legal team was very professional, accessible and responsive to the counterparty.
- EPA is fraught with complications and problem terms for a small developer. The joint and several clause curtails a small developers ability to partner with a large developer. Difficult to assess contract risk.
- 5 year ratchet clause penalizes bidders if the wind blows less than expected, or if hydro flows are low, for two of the five years.
- The pricing options should include escalators which are more appropriate for power projects than the CPI.
- Changes in the EPA to reduce price include:
    - Performance security – development security is fine but why do you need performance security once the plant is operational.
    - Term – there should not be a term restriction – allow same term as Hydro's projects which will serve to reduce costs.
    - Risks – suppliers can effectively manage construction and financing risks but there are other risks that they cannot manage well such as water rights.
- The policy direction in the Province's 2002 and 2007 Energy Plan that incremental generation in BC is to come from IPPs is largely driven by the notion that IPPs are more capable of managing risks (development, operating, and cost) than BC Hydro and that by having IPPs will shield the rate payers from risks typically associated with power projects. For each risk, the party best able to manage/analyze/price the risk should do so and not the party with the deepest pockets.
- The risk allocation provisions in BC Hydro's EPA agreements are reasonable based on the willingness of financial entities to finance such arrangements.
- Have to look at the totality of contract provisions when assessing the overall balance of risk and not just individual provisions.
- It should be noted that the delivery term shortfall, performance security, and firm/non-firm pricing do not exist in small scale procurements such as SOP. The size of the procurement and how important it is to an overall strategy also matters in terms of how/whether risk is allocated.

- The SOP EPA should be updated for optimal risk balancing every 2 years to match the pricing review timing.
- For large Calls, BC Hydro should issue the draft EPA sooner. The EPA is the target against which an IPP will select his best-fitting project and against which he will refine the design and studies throughout the bidding period.
- A preview of a short EPA term sheet is of limited value. Too frequently the final detailed clauses in the much longer final EPA are not what bidders were expecting after reading the shorter term sheet. The project design is not optimal, the studies are not quite on target and in some cases the wrong project might get chosen to be the one that is bid.
- The balance of risk between the utility and suppliers is appropriate. However, I have concern with comparing EPA prices with BCH project prices. EPAs are largely risk free since the developers absorb nearly all risks. Alternatively, development cost escalation, First Nations risk and operating risks for BCH projects are absorbed by BCH ratepayers. Since the public doesn't appreciate these crucial differences and don't appreciate that EPA project ratepayers from considerable risk.
- By requiring each wind or hydro plant to deliver firm energy, with penalties for under-delivery and greatly reduced prices for surplus, BC Hydro has offloaded risk that it could have pooled – e.g., wind is weakly or even negatively correlated with streamflow – onto individual plants with uncontrollable production. We agree there is a possibility of too much water/wind altogether (the consequence for BC Hydro being spill or re-sale at a loss). BC Hydro tries to make that contingency the IPPs problem, and succeeds, but then the IPP hands the problem back to BC Hydro in the form of higher prices and higher attrition. The total cost of generation supply goes up because (a) risk is not pooled and (b) the cost of risk is higher to the smaller, privately-financed IPP than it is to BC Hydro. Uncontrollable and controllable risk in the CPC EPA work opposite to the way lenders see risk. Lenders are comfortable with controllable risk and adverse to uncontrollable risk. The EPA in several places allows foregone production resulting from plant unavailability (controllable via maintenance practice) to be counted beneficially as production, whereas it loads 100% of uncontrollable streamflow/wind risk onto the IPP.

5. <u>Contract Management and Payment Administration</u>

- Very pleased with contract management activities. BC Hydro has developed a spreadsheet to keep track of meters. The process is very efficient and well done.
- Contract management process has gone very well. The large excel spreadsheet developed by BC Hydro is complex. BC Hydro has a good support team to deal with counterparties. Management of the contracts has been good.
- Once the bidder gets through the procurement and interconnection processes with COD in place, the contract management and billing function works well.

6. Other

- Concerned that Government will crowd out private developers.
- Questions whether BC Hydro really wants to receive the power. Object of BC Hydro has been to write contracts not necessarily to receive energy. That has been the perception in the industry. Attrition rate is 75% - too high.
- Signing contracts with attractive pricing but are not viable projects. This is inconsistent with government policy.
- **Reasons for high attrition rate include:**
    - Political interference or reversal of policy – it is hard to raise money based on government policy.
    - Government policy changed after the bids were received.
    - Viability and sophistication of developers.
    - Quality control in the process – subjective approach.
    - EPA drives development – not a lot of money spent up front.
    - Firm delivery requirements.
    - Capacity factors.
    - Interconnection costs/process.
    - Environmental permitting.
    - Political risk related to long lead time.
    - Companies bid with insufficient information.
    - Low ball bids in hope of securing contracts – this ultimately jeopardizes the chances of success for legitimate bids as well as the overall prices for power.
    - Attrition is a direct result of developers not pricing in the risks built into BC Hydro's contract terms.
    - Bid price is too low because (1) the developer needs a contract to secure funding; (2) the developer is somewhat inexperienced and makes fatal mistakes; and (3) developer is unable to assess risk inherent within the terms of the EPA.
    - EPA terms are too onerous and punitive, making it difficult to assess risk, especially when attempting to develop variable resources such as no flow- throughs for taxes.
    - EPA terms make it difficult to attract partnership funding, as well as institutional financing without severe financial terms.
    - Calls for power are irregular, making it difficult for developers to stay in the game long enough to plan for project development. Shareholders won't support developers who can't provide some level of certainty
    - No market signals and ad hoc calls creates a stop and start mentality which in turn nurtures a false sense of experience. Developers don't stick around.
    - Time to process CFT's and RFPs into results spans way too much time for projects that have fixed costs. Market and commodity cycles of 2008 and 2009 are a clear example of the effects on project costs and bid prices. Results need to be announced within 3 months of receipt.

- Bidders submit artificially low prices so that they will be awarded an EPA without the intention of building and operating the project, instead seeking to sell the EPA and project to a third party.
    - Many bidders are inexperienced and have never constructed a project of the size tendered before. They rely too heavily on EPC contractors without the ability to effectively manage them.
    - Bidders do not have the financial capability to construct the project but instead rely on the EPA to be able to raise capital.
    - Insufficient energy resource data.
    - Insufficient project developer robustness, capitalization, and certainty of financing.
    - Development cost increases between time of bid and awarding of contracts.
    - Inadequate due diligence on the price. BC Hydro has awarded EPAs at prices that in our view it could have known were not adequate to get the project financed.
    - Inconsistent policy and "pulled plugs" (e.g. VIGP, the F06 coal awards, Transmission Expansion policy/Section 5 hearing, shifting Call volumes) have in the past kept larger players – with skills and development money and no interest in under-bidding – hesitant to enter the market.
    - The complex form of the EPA and in particular its offloading of price risk, as well as volume risk, onto the IPP.
    - The time lapse between bid due date and award renders bids out of date. This results in the attrition of a lot of projects when component and labor costs rise beyond the capability of the project to sustain them. As a general principle, faster turnaround or some form of market – (not CPI) indexing is needed.
- BC Hydro is in an inherent conflict given its role as supplier and purchaser.
- We haven't bid into the Standing Offer program because the price is too low.
- Junior developers think they know what they are doing but many don't. Reasons:
    - bids are too low.
    - Inexperience.
    - Inability to effectively assess risk.
    - Too many starts and stops in the procurement process.
- Procurement process has to support learning process in the industry.
- The removal of BCUC from review of power calls and contracts is not a good idea. Favored BCUC process with cross examination and the opportunity to bring forth evidence.
- The SOP works well for small hydro projects. The prices offered are not economical for wind projects.
- The approach that BC Hydro takes in trying to ensure that all resources have an equal opportunity to compete and to reflect their own generating resource (the large hydro dams) result in BC Hydro designing a call and the contract terms that are skewed towards thermal projects. Since very few to none

thermal projects participate in the calls (biomass has their own calls), the calls are designed for the wrong technologies to participate.

- BC Hydro should maintain adherence to the Call schedule.
- The Dokie Wind process was a problem. There was no process involved and no scrutiny. This was a major shortcoming in terms of transparency.
- With regard to the SOP program, the problem with the program is that the application guidelines try to fit the SOP into the Call for power requirements and intentions which small projects have difficulty meeting.
- Suggestion for improving the process – when a review is required consider the proponents point to improve the program instead of giving lip service to the review process with predetermined objects for change that only satisfy the utilities needs.
- Rate for Energy Procurement Process:
    - Fairness – Average.
    - Openness – Average.
    - Transparency – Poor – what is presented is interpreted differently at application review.

7. <u>Strengths and Weaknesses of BC Hydro's Energy Procurement Process</u>

- **Strengths**
    - BC Hydro's credit rating/high creditworthiness of BCH – this reduces financial risk.
    - Generally BC Hydro has run clear, fair and transparent Calls. BC Hydro is very good at running the mechanics of procurement steps once the Call rules are set, including process updates and posting Q&A's.
    - The long-term contract. Offering EPAs up to 40 years is a strength.
    - BC Hydro's post-award reports have been well done and are informative.
    - Time of delivery table (which is good for wind projects as wind energy profiles follow the load/demand).
    - The procurement process fits into the context of the overall long-term electricity plan.
    - BC Hydro's record of fair and reasonable contract management and payment administration during the many years of an IPP project operation is a strength.
    - Firm pricing.
    - Competitive process to ensure lowest cost to ratepayers.
    - Risk mitigation from buyers to sellers to the benefit of BCH ratepayers.
    - Price inflation adjustments.

- **Weaknesses**
    - The process is not transparent enough.

- The process does not provide enough information to allow companies to pursue projects with full information (which would then allow companies to allocate resources effectively).
- No regular timing for procurement – creates uncertainty and increases risk.
- The erratic intervals of when the power calls occur makes it difficult for suppliers to plan ahead and deters investment.
- BC Hydro has done a sub-optimal job of risk allocation in the Electricity Purchase Agreements.
- BC Hydro has taken too long between announcing calls.
- Some Calls have been very slow such as the Clean Call which took 500 days.
- Procurement process tends to be reactionary, not visionary when it comes to supporting the growth of the renewable energy industry, jobs in rural communities and tax revenues for communities and the Province.
- Contract terms are way too complicated, which increases risk and thus the bid price. Onerous terms related to First Nations consultation, joint and several liability, and not allowing flow through of tax increases.
- BC Hydro does not seem to honor their own rules regarding contracts that have failed, i.e. Dokie and issuing contracts to developers that don't meet technical criteria.
- Wind integration adjustment of $10/MWh is higher than almost all other North American jurisdictions and is based on a 20% wind penetration rate, which is much higher than actual experience.
- Five year ratchet clause is draconian, essentially using variability in energy delivery to reduce price (increasing risk and bid price) and above all making developers responsible for when it rains or when the wind blows.
- The evaluation criteria used by BC Hydro to determine which potential bidders meet the eligibility requirements for financial resources and experience are set too low. For larger projects the eligibility criteria should be set higher than those for smaller projects. One option may be to set higher net worth requirements for larger projects.
- The practice BC Hydro uses to select winning bids based on the lowest adjusted bid price after having screened out projects that do not pass the eligibility results in a higher attrition rate. The BC industry is still relatively immature and some developers that do not have any intention of constructing or operating the facility will submit low prices in order to obtain an EPA so that they can sell the EPA to another party. In order to have a sustainable industry, proponents should be required to continue to have equity/economic participation in the project after COD.
- Prior power calls have been structured to enable all sources to participate and to allow all to compete on a level playing field. In practice this sounds reasonable and fair but in practice it is sub-optimal

  because two resources, hydro and wind, dominate (biomass has their own power calls). Power calls should be structured to reflect this reality and reflect the inherent characteristics of these technologies.
  - Some projects were approved by negotiated price without going through the procurement process (i.e. Dokie).
  - Lack of price disclosure makes it difficult to review merits of specific projects.
  - The process is very long and does not respect its own schedule and the reasons for delay are not disclosed.
  - The “self-sufficiency” and “insurance” requirements effectively force BC Hydro from managing supply price and risk in the most effective manner. This extra energy can only be sold on the spot market, causing a buy-high sell-low situation with a very large price spread, to the detriment of BC.
  - There is considerable regulatory and First Nations uncertainty which also leads to higher prices to BCH.
  - The overriding weakness is the pricing structure of the EPA as exemplified by the CPC EPA. The level of price risk that IPPs have to take on is too great and should be balanced by BC Hydro. For example, we expect that the freshet constraint raises the prices of hydro IPPs by more than the cost to BC Hydro of pooling freshet risk and paying the cost of a possible surplus. The net effect would be a higher total cost of supply.

- **Areas For Improvement**
  - Sharing information.
  - Answering questions transparently.
  - Assessing bids in a timely manner.
  - Providing adequate time for response (when asked to rebid).
  - The entire process needs improving.
  - Eliminate the 5 year ratchet clause and accept renewable energy for what it is.
  - Utilize BC Hydro’s vast storage of water for shaping variable renewable energy to provide a firm product for export.
  - If variability is an issue, put a reasonable price on storage and allow developers to purchase firming products.
  - Look beyond the domestic market toward export opportunities.
  - Assess and define a more reasonable wind integration cost using actual penetration rates in BC.
  - Reduce or eliminate onerous contract terms that simply result in increased development risk and thus increased bid prices. The net result of these onerous terms is higher energy prices and such terms are not needed. This will likely reduce attrition as well.
  - Develop a regular schedule for procurement (this requires the identification of sustainable markets – both domestic and for export and export may require firming products).

- Export markets need to be identified; firming products defined and offered; access to transmission to export markets is also required. Contrary to the BC Energy Act, exports will likely affect ratepayers, but BC Hydro could ensure that such affects are net positive in the long term.
- BC Hydro needs to come to terms with the fact that each renewable fuel type has different costs associated with development. Currently BC Hydro's thinking is stuck in a "price above all other factors" process. For example, wind projects, especially small wind projects are quite expensive, but can be excellent projects for remote communities. Other jurisdictions have recognized this (i.e. Quebec, Ontario, and Manitoba, and a number of US states) and have fuel specific calls, some with FIT that define reasonable prices to build.
- Allow for flow throughs. Projects have very thin margins and extra-ordinary increases in taxes related to revenues, First Nations revenue sharing can adversely affect project economics.
- Better price disclosure.
- All procurements should be subject to transparent and open regulatory review.
- Better adherence to procurement schedules.
- Policy direction from government to allow (a) BC Hydro more flexibility in meeting demand in cost effective ways; (b) over-acquired electricity allowed to be applied to new domestic demands including electrification of vehicle fleet and a general shift off fossil fuel use for heat and process needs.
- Time elapsed from bid due date to announcement of awards.

8. <u>Overall Assessment of Energy Procurement Process</u>

- Very poor. It took way too long which jeopardizes the viability of companies and was also not open or transparent.
- We were desperately trying to have a conversation with BC Hydro/BCTC to assess the viability of our projects and interconnection and were essentially provided no information at all. In fact, we spent $30,000 on studying an interconnection scenario that BC Hydro/BCTC knew had no chance of being allowed by the company. This lack of transparency provided false hope and wasted private sector resources.
- After the call process was finalized, the leadership of the procurement process refused to meet and sent their junior staff to meet with us along with lawyers. In that meeting, they provided no information of real substantive value.
- The company has participated in many procurement processes across Canada, including FIT and RESOP (Ontario), older Ontario Hydro NUG contracts, wind RFPs (Quebec), Saskatchewan (thermal) All of these PPAs have much simpler, less risky pricing, and are less punitive than the BC Hydro EPA. For instance, both Ontario and Quebec have a single price paid for the delivery of a kilowatt-hour of green electricity. Attrition is substantially lower.

APPENDIX E

Assessment of the BC Hydro EPA and Related Risk Issues

BC Hydro has used a large variety of contract forms with IPPs over the years. For the purposes of this analysis, the pro forma or specimen electricity purchase agreement (EPA) issued in connection with the 2008 Clean Power Call will be reviewed. In one case, another provision dealing with First Nations Consultation which was added as of October 8, 2010 to the specimen EPA for the Bioenergy Phase 2 Call will also be reviewed. The scope of this review covers a summary assessment of its quality and complexity, a risk by risk discussion of the major provisions of the contract that allocate risk between the buyer and the seller and a comparison of the pricing provisions with alternatives drawn from a sampling of other jurisdictions.

A. General Assessment of Quality and Complexity

The EPA is a formidable document showing a high level of knowledge of power contracting. The legal draftsmanship is comparably high and undoubtedly a source of pride to its authors. As such a technically precise and formidable document, it may screen out developers who lack the requisite contractual experience and do not compensate for their deficiency by engaging experienced power contract attorneys. Moreover, in most cases, the pricing formulae extend in complexity beyond the skills of even experienced counsel. The EPA's pricing provisions call for technical engineering and other analytical skills which match the project's resource data to the pricing constraints in the EPA in such a way that revenues are optimized and the risks of prolonged, and possibly fatal, "cross-overs" of costs and revenues are minimized.

With some effort, it is possible to reduce the legal complexity of the EPA. Care is required since simplification always means a loss of precision and the introduction of additional areas where the contract's interpretation may be disputed. While the legal complexity of the contract may have had a negative effect on the ability of developers to bring their project to completion in accordance with its terms, the effect is likely a marginal effect overwhelmed by more serious problems encountered in the project's siting and licensing efforts, potential mismatches of resource availability and the EPA's pricing constraints, other bidding errors and a host of other potential shortcomings in the development effort. As a result, if the endeavor is to reduce the future attrition of projects executing an EPA of this type, the possible revision of the pricing provisions would appear to be a more fruitful area for inquiry than the simple task of simplifying the contract language.

B. The Major Allocations of Risk between Seller and Buyer in the EPA

1. Milestones, Milestone Extensions and Delays, Remedies for Milestone Failure.

The specimen EPA contains an initial milestone for BCUC acceptance for filing as an Energy Supply Contract without conditions (BCUC Acceptance) (§3.1), failure of which within 150 days of the execution, when each party has made the required effort to obtain the same (§3.3), results in a mutual termination right. That termination right, which is generally liability-free (§3.5), must be exercised between the 150th day and the 180th day (or before BCUC Acceptance or Exemption) (§3.4). If the termination right is not exercised in time, it lapses and it is not clear how either the Buyer[1] or the Seller can then perform if BCUC Acceptance never occurs. This uncertainty should be resolved in some way that will relieve financing parties of the concern that the EPA cannot be enforced against the Buyer.

A Note to Proponents in the specimen EPA reserves BC Hydro's right to amend the regulatory condition to make the EPA subject to any pending regulatory proceeding in progress or to extend the date for satisfaction or waiver of the condition. Both possibilities impede financing since funds will not be advanced until the uncertainty is removed of failing to satisfy the condition or of having the EPA terminated for regulatory

[1] If the Buyer must perform the EPA under applicable law even if there is no BCUC Acceptance or Exemption, and if this obligation is clear under law, then the lapsing of the right to termination should not prevent financing and the obligation to commence and continue development under §4.1, after the right expires, can be performed by the Seller.

reasons. Both are disfavored within the industry and their elimination is more in keeping with industry standards.

If possible, the risk of having the EPA terminated for regulatory reasons should ideally be resolved before execution or made subject to readily predictable outcomes known within a very short period thereafter. While the risk remains unresolved, construction financing is delayed, funds to advance the project continue at risk and the cost of the delay erodes the ability of revenues to carry the project.

A date certain (Guaranteed COD, as defined in ¶57 of Appendix 1) appears to be the intended milestone date by which the Seller must achieve the Commercial Operation Date (COD as defined in ¶17 of Appendix 1). By such date, the Seller must possess all Material Permits as defined in ¶71 of Appendix 1. The risk of permit failure is clearly on the Seller (§§ 4.2, 5.2(a), 16.1(a), ¶49(g) of Appendix 1). The only relief for the Seller is to terminate the EPA for this reason at the earlier of 180 days before the Guaranteed COD and the second anniversary of the execution of the EPA and upon such termination, to pay a reduced damage amount to the Buyer (§§16.2(a), 16.3, 16.5(a), 16.7, 16.9(c)). In the event that the Seller does not have all Material Permits by the date which is the earlier of the Guaranteed COD or the third anniversary of the execution of the EPA, the Buyer has a right to terminate the EPA with associated payment obligations from the Seller to the Buyer (§§16.1(a), 16.4(a) (payment of the lesser of Performance Security (¶87 of Appendix 1) and the positive amount, if any, by which Buyer's Economic Losses and Costs exceed the aggregate of the Buyer's Gains).

The Seller has the duty to meet the Guaranteed COD and is relieved from strictly performing that obligation only by Force Majeure Days and delays in completing the Interconnection Facilities (§§5.1, 5.8). In the latter regard, if the Estimated Interconnection Completion Date (¶41 of Appendix 1) is later than 90 days before the Guaranteed COD, then the latter is extended until 90 days after the former completion date (§5.8). Force Majeure Days (¶50 of Appendix 1) are the number of days the Seller is delayed by Force Majeure as provided in §12. While Force Majeure has a definition which is largely conventional (¶49), there is a specific limitation preventing most problems obtaining Material Permits from being Force Majeure (¶49(g)), a provision which is not always present in industry contracts. Many contracts have some Force Majeure recognition of permit problems which may be limited to a specific number of qualifying days. In fact, the EPA has this feature for non-permit Force Majeure. For other qualifying causes of Force Majeure, the Seller's Force Majeure extension of the Guaranteed COD is limited to 180 Force Majeure Days, although the Buyer does not acquire a termination right for the failure to achieve the Guaranteed COD until that date plus 365 days plus all Force Majeure Days (limited as indicated to 180 days) have passed (§16.1(b)).[2]

In addition to terminations rights for the Seller's failure to obtain all Material Permits and achieve the COD by the respective deadline dates described above, the Buyer has termination rights under §16.1 (e) for the Seller's failure to complete necessary steps in the interconnection process (¶15(d) and 15(e)). In this regard, Buyer Termination Events (¶15 of Appendix 1) are defined to include failure to meet the following interconnection requirements

> (d) the Seller has failed to complete any step in the process for interconnecting the Seller's Plant to the Transmission System in accordance with the requirements and time limits specified by the Transmission Authority, and such failure results in the Seller's Plant losing its position in the queue for the Competitive Electricity Acquisition Process as described in the OATT Attachment P, filed June 8, 2007 by the Transmission Authority with the BCUC, in compliance with Directive #20 of the BCUC's decision accompanying Commission Order G-58-05 concerning the Transmission Authority's OATT application;
>
> (e) without limiting subsection (d), the Seller has not, within 30 days after receipt from the Transmission Authority of a Combined Study Agreement for the Seller's Plant, executed and delivered that Agreement to BCTC together with the applicable fee in the amount and form prescribed by the Transmission Authority;

Upon termination for the Seller's failure to meet the deadlines for Material Permits (§16.1(a)), and the Guaranteed COD (§16.1(b), or Seller's failure to complete necessary steps in the interconnection process (§16.1 (e), Buyer Termination Events as defined in the above ¶15(d) and 15(e) of Appendix 1), the Buyer's remedies include the payment

[2] Presumably, the Seller is in default for failing to achieve the Guaranteed COD at the earlier date which does not include the 365 days (§5.1), but the cited provision §5.1 is not clear whether the Force Majeure Days are also limited to 180 days or not.

under §16.4(a) of the lesser of Performance Security (¶87 of Appendix 1)[3] and the positive amount, if any, by which Buyer's Economic Losses and Costs exceed the aggregate of the Buyer's Gains.[4]

If the COD is delayed, liquidated damages (LD) are due under §13.1 for the period between the Guaranteed COD plus Force Majeure Days and the date when the Buyer's right to terminate the EPA arises under § 16.1(b) (which includes an extra 365 days)[5], whether or not such right is exercised. The manner of calculating the LDs is the same for the late COD as for the shortfalls in delivery which occur after the COD. That algorithm is set forth in §13.2.

2. <u>Force Majeure Exclusion of Permit Risks Affecting Milestone Performance</u>.

The risk of permit failure is clearly on the Seller (§§ 4.2, 5.2(a), 16.1(a), ¶49(g) of Appendix 1). The Seller has the duty to meet the Guaranteed COD, as defined in ¶57 of Appendix 1), and is relieved from strictly performing that obligation only by Force Majeure Days. However, there is a specific limitation preventing most problems obtaining Material Permits from being Force Majeure (¶49(g)). The subject provision specifically excludes the following:

> (g) any refusal, failure or delay of any Governmental Authority in granting any Material Permit to the Seller, whether or not on terms and conditions that permit the Seller to perform its obligations under this EPA, except where such failure or delay is a result of an event described in subsection (a), (b), (c) or (e) above.

[3] "Performance Security" means a letter of credit in the form specified in Section 14.4 in an amount that varies at different times over the term of the EPA from a low \$2.50/MWh to a high of \$8.00/MWh, multiplied in each case by the Annual Firm Energy Amount where the Firm Energy delivered to the Buyer in any period is deemed to include deemed Eligible Energy pursuant to section 7.8 and section 7.11, as well as other adjustments for certain Force Majeure, authorized planned outages and other amounts when delivery is excused.

[4] See: §16.6 for the determination of these terms. In contrast to industry norms, the definitions of Economic Losses and Gains, set forth in §16.6(f)(ii) and (iii), respectively, imply that the Terminating Party that terminates the EPA could have both gains and losses from the same contract termination. It is more conventional to think of either a Loss or a Gain as resulting from a single contract's termination, whereas both Gains and Losses could exist when a collection of contracts was terminated.

[5] The provision is not clear whether Force Majeure Days are limited to 180 days or not, although the better view is that this was the intention since otherwise, there could be a Force Majeure which extended for at least 180 plus 365 days which would not entitle the Buyer to receive liquidated damages for COD delays.

As set forth above, the only relief for the Seller is to terminate the EPA when the Material Permits have not been obtained by the earlier of 180 days before the Guaranteed COD and the second anniversary of the execution of the EPA.

3. The General Force Majeure Standard.

The Force Majeure has a definition which is largely, but not entirely, consistent with the tight provisions which are common in the industry (¶49). The two principal features of the EPA standard are that the event in question affecting the performance of a party is outside the control of the Party and that the Party is unable to perform as a result as a result of the event. The definition states the first principle that the event be outside the control of the party. In this regard, it is tighter than many force majeure clauses in the industry which contain a lesser qualifying principle that the event be outside the reasonable control of the party. For such clauses, the need for the affected party to exert greater than reasonable action to control the event would cause the event to qualify under the first principle as an excuse for performance. The definition in question specifically provides as follows:

> "Force Majeure" means, subject to the exclusions in section 12.2, any event or circumstance not within the control of the Party invoking Force Majeure and, to the extent not within that Party's control, includes:
>
> (a) acts of God, including wind, ice and other storms, lightning, floods, earthquakes, volcanic eruptions and landslides;
>
> (b) strikes, lockouts and other industrial disturbances, provided that settlement of strikes, lockouts and other labour disturbances shall be wholly within the discretion of the Party involved;
>
> (c) epidemics, war (whether or not declared), blockades, acts of public enemies, acts of sabotage, civil insurrection, riots and civil disobedience;
>
> (d) acts or omissions of Governmental Authorities, including delays in regulatory process and orders of a regulatory authority or court of competent jurisdiction;
>
> (e) explosions and fires; and
>
> (f) notwithstanding subsection 12.2(f), an inability of the Seller to achieve COD solely as a result of a delay by the Transmission Authority in completion of Network Upgrades or other work to be undertaken by the Transmission Authority on the Seller's side of the POI, if and to the extent such delay is not attributable to the Seller or the Seller's Plant;
>
> but does not include:

> (g) any refusal, failure or delay of any Governmental Authority in granting any Material Permit to the Seller, whether or not on terms and conditions that permit the Seller to perform its obligations under this EPA, except where such failure or delay is a result of an event described in subsection (a), (b), (c) or (e) above.

The provision (g) contains the exclusion of permit Force Majeure discussed above.

The provisions of §12.1 state the second principle that the Party be unable to perform an obligation in question due to the Force Majeure event in order to be excused from performance. In this regard, it is also tighter than a minority of force majeure clauses in the industry which contain a lesser qualifying principle that performance is either prevented or impaired by the event outside the reasonable control of the party. The lesser standard of "impairment" is generally thought to be generous to the affected party and may undermine the enforceability of the contract obligations to an extent that is not desired for a long term energy supply agreement.

The provisions of §12.2 limit the reasons for which Force Majeure can be invoked as follows:

> §12.2. A Party may not invoke Force Majeure:
>
> (a) for any economic hardship, or for lack of money, credit or markets;
>
> (b) if the Force Majeure is the result of a breach by the Party seeking to invoke Force Majeure of a Permit or of any applicable Laws;
>
> (c) for a mechanical breakdown or control system hardware or software failure, unless the Party seeking to invoke Force Majeure can demonstrate by clear and convincing evidence that the breakdown or failure was caused by a latent defect in the design or manufacture of the equipment, hardware or software, which could not reasonably have been identified by normal inspection or testing of the equipment, hardware or software;
>
> (d) if the Force Majeure was caused by a breach of, or default under, this EPA or a wilful or negligent act or omission by the Party seeking to invoke Force Majeure;
>
> (e) for any acts or omissions of third Persons, including any Affiliate of the Seller, or any vendor, supplier, contractor or customer of a Party, but excluding Governmental Authorities, unless such acts or omissions are themselves excused by reason of Force Majeure as defined in this EPA;
>
> (f) for any disconnection of the Seller's Plant from the Transmission System, or any Transmission System Outage; or
>
> (g) based on the cost or unavailability of the Energy Source for any reason, including natural causes, unless transport of the Energy Source to the Seller's Plant is prevented by an event or circumstance that constitutes Force Majeure as defined in this EPA.

This collection of exclusions from the Force Majeure clause is also generally consistent with industry norms. The last provision mirrors other common provisions in the industry which disqualify as Force Majeure events the unavailability of fuel for a plant unless a transportation event outside the plant owner's control, which otherwise qualifies as a Force Majeure event, is the cause. The EPA reference to the defined term, Energy Source (§36 of Appendix 1), makes clear the exclusion captures the intermittent energy sources, wind and water, which may be unavailable for "natural causes", as well as biomass which may be available but priced at a cost which makes performance difficult. In the latter regard, the exclusion of the cost of the Energy Source as a Force Majeure event overlaps with the exclusion of "economic hardship" (§12.2(a)) as a cause of a Force Majeure event.

4. <u>Force Majeure and Change in Law Risks</u>.

The risk of a change in law which materially affects the performance of either party to the EPA is not specifically addressed in Force Majeure clause or any other provision of the EPA. This is not unusual in the industry. However, some contracts today explicitly exclude the change in law risk from the Force Majeure clause for both parties. Other contracts have specific provisions which assign the risk of one or a limited number of changes to the buyer and all others are said to remain with the party affected by the change.

The effect of silence in the Force Majeure clause is that the other provisions of the Force Majeure clause must be interpreted and applied to the effects of the change in law which has occurred. If the change of law creates economic hardship or lack of money, credit or markets, §12.2(a) will prevent the invocation of Force Majeure for these reasons. With these limitations, the party affected must still show that he is unable to perform without taking into account the excluded effects of the changed law. This showing may not be possible and the affected party is still obligated to perform under the EPA.

If the showing were possible without regard to the excluded factors, such as when performance is made illegal, then the Force Majeure clause would apply to excuse performance (see also: ¶49(d)). Other common law may also be applicable, raising the question whether excused performance of one party, which serves to excuse the performance of the other party, would result in a termination of the EPA in accordance with its terms or under the other common law principles. The difference would affect whether or not the termination clauses applicable for prolonged Force Majeure (§§16.1(c) and (d) and 16.2(b)) would result in any payment obligation of the Seller to the Buyer such as provided for in §§16.9(b)(ii) and 16.9(d). Common law might provide otherwise and free the parties from any obligation to the other upon terminations for illegality.

5. <u>The General Risk of Events or Circumstances Outside the Control of the Seller</u>.

This section of the analysis simply summarizes the meaning of the various EPA provisions discussed above regarding the circumstances when a Party would be excused from performance. Since the Seller under the EPA is the principal obligor in terms of the number and scope of its obligations, the issue of excuse from performance applies with much greater force to the Seller. The short summary is that the circumstances for excuse for performance are very limited under the EPA. An event must be outside the Seller's control even if the Seller is making greater than reasonable efforts to control the circumstance. The performance of the Seller must be prevented, and not merely impaired or made more difficult or costly.

As a result, most events which impair performance or make it more difficult or more costly are risks assigned to and absorbed by the Seller under the EPA. The Seller would accordingly have no choice but to price the risks absorbed and bid accordingly. Whether or not the price premium is competitively bid down to a level that represents a reasonable value for the Buyer is beyond this contractual analysis. However, reports done for BC Hydro by non-legal experts have raised this value question in the past suggesting that the price premium may be too high and should be formally studied.

At such a time of study or independent of a study, modest changes to the Force Majeure provisions could be considered in order to facilitate financing and lower certain of the price premiums. In this category would be a change to events outside the reasonable control of the party affected and acceptance of permit Force Majeure limited to a specific number of days of relief. Changes to the pricing constraints, which, for example, could introduce more flexibility into the delivery requirements, making Liquidated Damages (LDs) less likely to be due, could be considered as mitigation of the exclusion of weather conditions from Force Majeure and would be adequate mitigation depending upon their character.

Among the risks absorbed under the EPA by the Seller are weather conditions, availability and pricing of biomass supply, water rentals, local and other taxes, permit impediments, First Nations claims and other similar development challenges.

6. Capital Cost Escalation.

The EPA contemplates under §7.6 and Appendix 3 the bidding by the Seller of a Escalated Firm Energy Price payable under the complex, and accurate, pricing provisions of the EPA for Firm Energy up to Seasonally Firm Energy Amounts in each season. A Non-Firm Energy Price is also provided and takes two forms at the option of the bidder, one which tracks a energy index value (Dow Jones Mid-C Daily Non-Firm On-Peak or Off-Peak Index) and another which tracks a table of future prices set by BC Hydro for Non-Firm Energy. Factors adjust the prices paid to account for the difference in value to the Buyer for time of day and time of the year. Escalation is limited to a percentage of the Consumer Price Index (CPI) bid by the Seller (§§ 1.1(b), (c), (g), (h), 3.1, 3.2, 3.3, 3.4).

While bid prices are allowed to escalate by a percentage of the CPI, no provision allows an adjustment in the bid price to take specific account for the variety of risks that can change the capital cost of a project after the time of the bidding. These risks include a change in design of the plant; inability to lock-in pricing in a timely fashion for plant equipment and/or construction services; extra permitting requirements; change in the cost of the interconnection facilities connecting the plant to the Interconnection Point; delay in regulatory approval, receipt of permits, financing and construction; and greater than expected data and analyses requirements.

It is important to point out that capital cost escalation can include more than increases in the “bricks and mortar” cost of the plant itself. All development and financing costs are capitalized, along with the cost of equipment and construction services. All are serviced exclusively from the expected revenues which are dependent on the bid prices for the EPA. When long and complex permitting and regulatory requirements during development are expected, the bid prices are increased to a commensurate degree. When such requirements are not adequately anticipated, the risk of project attrition increases.

7. Power Pricing and Price Escalation.

Appendix 3 contains the pricing provisions of the EPA and sets forth the definitions and protocols for the payment (under §3.1 of Appendix 3) to the Seller of a Escalated Firm Energy Price (§§3.1 and 3.2 of Appendix 3) for Firm Energy (¶46 of Appendix 1, based on all Eligible Energy, ¶34, which includes Metered Energy and Deemed Eligible Energy pursuant to §§ 7.8 and 7.11) up to Seasonally Firm Energy Amounts in each season. A Non-Firm Energy Price is also set forth for the payment to the Seller (under §3.3 of Appendix 3) for Non-Firm Energy (¶79) and takes two forms at the option of the bidder, one which tracks a energy index value (Dow Jones Mid-C Daily Non-Firm On-Peak or Off-Peak Index) (the Option B Non-Firm Energy Price defined in §1.1(h) of Appendix 3 and another which tracks a table of future prices set by BC Hydro for Non-Firm Energy (the Option A Escalated Non-Firm Energy Price defined in §3.3 and adjusted in §3.4 of Appendix 3). Factors adjust the prices paid to account for the difference in value to the Buyer for time of day and time of the year. Escalation for Firm Energy and for the Option A Escalated Non-Firm Energy Price is limited to a percentage of the CPI bid by the Seller (§§ 1.1(b), (c), (g), (h), 3.1, 3.2, 3.3, 3.4).

In the body of the EPA, rather than stating the delivery obligation in terms of all Metered Energy first and then stating a minimum delivery obligation, the Seller is said to have only an obligation to deliver the fixed amount of the Seasonally Firm Energy Amount (§7.2). The Seller also has a duty to deliver Energy to no other entity (§7.4); the Buyer's obligation to purchase is framed in terms of the Eligible Energy (§7.3), which is consistent with the statement of obligations to pay in Appendix 3, both of which are based on Eligible Energy that includes Deemed Eligible Energy under §§7.8 and 7.11). The circumstances in which the Buyer is obligated to pay for Deemed Eligible Energy, which is not actually delivered Energy, are limited. §7.8 requires that the Seller cannot deliver solely as a result of a Transmission System Outage not caused by the Seller or not caused by events beyond the control of the Buyer or the Transmission Authority (excluding in this regard, Force Majeure events, §7.8(d)). Qualifying events appear then to be those for which the Buyer or the Transmission Authority exercise control.[6] §7.11 are cases where the Buyer curtails generation at the Seller's plant to avoid safety, stability or similar risks.

Both parties are excused from performance for a similar set of reasons under §7.7. For the Seller, these excuses are important since they serve to limit the amount of Liquidated Damages payable by the Seller when, under §13.2, the Delivered Eligible Energy is less than the Seasonally Firm Energy Amount for the Season in question. All excuses in §7.7(a) reduce the target amount of required energy. However, Delivered Eligible Energy does not include Deemed Eligible Energy[7] and more importantly, the target amount of energy is not reduced for events of Force Majeure of the Buyer that prevent delivery or for failures of the Buyer to perform which have not yet matured into a Seller Termination Event (recognized for these purposes under §15 and §7.7(a)((v)) under ¶113(c) of Appendix 1) Asking the Seller to pay Liquidation Damages of any amount when the Buyer is responsible for the Seller's inability to deliver seems questionable at best. Industry norms are not so harsh. Generally when one party is excused by Force Majeure, the performance of the other party is also excused to a commensurate extent.

Since the Seller is paid its bid price under Appendix 3 only for amounts up to its designated Seasonally Firm Energy Amounts, the constraints on setting such amounts have significant impact on the Seller. Those constraints were fully disclosed from the start of the RFP process in the schedules to the RFP and in the Specimen EPA where they are evidenced, after the fact, in §§7.9 and 7.10. The latter provisions further constrain the Seller's Seasonally Firm Energy Amounts based on plant performance. The constraints are (i) that the Seasonally Firm Energy Amount for the System Freshet Season from May 1 to July 31 (¶118 of Appendix 1) must be no more than 25% of the Annual Firm Energy Amount (see §7.9(a)(ii)); (ii) that the Seasonally Firm Energy Amount for the System

[6] The reference in §7.8(a) to the fact that these qualifying events are events for which the Buyer is excused under §7.7(b) seems at least in part to be in error since events within the control of and attributable to the Buyer could be the cause of the outage.
[7] No suggestion is made here that Deemed Eligible Energy should be added to Delivered Eligible Energy.

Freshet Season must also be no more than one third of the sum of firm energy in the other Season; and (iii) that ***every five years***, starting after the first four complete Seasons, the Seasonally Firm Energy Amount for ***each Season*** shall be adjusted to the lesser of (a) the total amount of energy delivered in the Season in question, with certain adjustments for outages, that was met or exceeded in 80% of the occurrences of that season since the first anniversary of the COD and (b) an amount equal to 110% of the initially designated amount of the Seasonally Firm Energy Amount for that season as of the date the EPA was executed (§7.10).

In order to contend with these pricing constraints, the Seller must have adequate statistical data on the ability of its Energy Source to support generation in each season and the modeling capability to test different bid prices and different designations of the Seasonally Firm Energy Amount for each season in order to optimize its total revenues for Firm Energy and Non-Firm Energy, taking into account the Liquidated Damages due for under-delivery of Firm Energy (relative to the Seasonally Firm Energy Amount in each Season) under §13.2 and the drop in prices payable for Non-Firm Energy delivered in excess of the Seasonally Firm Energy Amount in each Season under §§3.3 and 3.4 of Appendix 3. This skill and these resources call for mature participants in the market.

It is enough at this point in the contractual analysis to make two points. First, the comments of IPPs on these pricing constraints include a description by a hydro-electric developer of the 5-year 80% rachet as "draconian" and the assessment by another developer that its bid price was forced up to adjust to the effects of the constraints. Second, a study whether the risk premium included in IPP bids to compensate the Seller for the risks implicit in these provisions may yield valuable information. Included in such a study would be a comparison of the effects on both the Seller and the Buyer of the present constraints to the effects of more flexible pricing provisions such as those in some of the industry EPAs reviewed below in the Appendices to this contractual analysis.

8. Energy Delivery Requirements, Shortfalls and Replacement Power Costs

As indicated above, Liquidated Damages (LDs) are payable under §13.2 in the event that in any Season the Delivered Energy, defined in that section substantially as Metered

Energy, is less than the Seasonally Firm Energy in that Season. Pursuant to §13.3, the payment of LDs is the exclusive remedy for the failure to achieve the COD on time or to deliver the Seasonally Firm Energy Amount, which otherwise under Section 7.2 is an unqualified obligation. Exclusivity does not affect however the right to terminate the EPA, such as the rights found in §16.1, for reasons related to these failures. When this §13.2 shortfall exists the formula for LDs determines the amount of the shortfall by giving the Seller credit for all reasons in §7.7(a) that excuse the Seller's delivery obligation. The unit damage amount is the greater of $5.00/MWh, escalated by the CPI and a formula for cover damages based on a replacement power cost equal to a proxy market price for peak and off-peak energy.

Two factors suggest that the amount of LDs that are actually paid may be lower than expected. Since the contract price is likely to be higher than the replacement price, the escalated $5.00/MWh is the relatively low unit damage amount which is expected. Secondly, the comparison each Season is between all Delivered Eligible Energy, including amounts priced as Firm Energy and as Non-Firm Energy, and the adjusted Seasonally Firm Energy Amount, which may have been driven down by the effects of analyzing the pricing constaints in the EPA.

The Seller is subject to an exclusive remedy provision which is a counterpart to the Buyer's provision. In §13.4, the exclusive remedy for the Seller is the price payable under Appendix 3. The Seller still has rights to terminate the EPA, such as in §16.2. The Seller's total liability is limited, except in certain cases which include termination of the EPA, to the an amount equal to 200% of the Performance Security in effect in the year in question under §13.5

9. Operational Performance Standards.

The operational standards in §6.2 of the EPA require operation in accordance with a collection of Project Standards (¶102 of Appendix 1) that are consistent with industry norms. As well under §6.2(b), the Seller is required to make commercially reasonable efforts to deliver Energy at a uniform rate within each hour. The wording of the standard protects IPPs who have no control of weather conditions affecting their Energy Source.

In general, operational requirements are sensibly crafted in terms of commercial reasonableness, with a few exceptions such as the duty of the Seller to remove or mitigate a Forced Outage with "best efforts" (§6.3(c)). When a Planned Outage must be re-scheduled at the Buyer's request, the Buyer sensibly compensates the Seller for costs incurred as a result of the re-scheduling (§6.3).

10. The Risk of Interruption or Price Escalation of Fuel Supply or Energy Source.

As indicated above, the risk of the availability and pricing of Energy Source is on the Seller (§12.2(g)). This applies even in cases where the costs of biomass supply and water rentals are largely beyond the control of the Seller. Some IPPs commented that a risk sharing of such costs was more appropriate. However, the absence of such sharing is not outside the norm for similar industry agreements.

11. Interconnection Costs.

The Buyer has the general responsibility for paying all costs incurred for the design, engineering and construction of the Interconnection Network Upgrades described in the Final Interconnection Study Report (§4.4, ¶¶ 60, 62). The risk of an untimely interconnection is shared in at least one respect since the Seller is granted an extension of the Guaranteed COD until 90 days after a new estimate of the interconnection deadline (§5.8). However, under the circumstances of waiting, particularly for a long time, for the interconnection to be complete when the plant is otherwise ready for the COD, the Seller is experiencing significant, unsupported carrying costs for which the Buyer assumes no responsibility (§5.6).

If, in the future, the Buyer will be responsible for constructing the connection facilities on both sides of the Point of Interconnection (POI), a pass-through of some part of the carrying charges might be explored as a means of reducing attrition and assuring the efficient planning of interconnections by the Buyer. Such a sharing is not common, however, in other jurisdictions.

12. Events of Default, Cure and Termination Rights.

Both parties have roughly comparable rights to suspend performance when a Buyer Termination Event or a Seller Termination Event, events that are more commonly referred to as matured Events of Default, exists under §§15.1 and 15.2, respectively. A provision which limits the period to 90 days for a Buyer Suspension has both advantages and disadvantages to the Seller.

Specific rights to terminate the EPA, that include the Buyer and the Seller Termination Events, as well as other specifically identified termination circumstances are defined for the Buyer and the Seller, respectively, in §§16.1 and 16.2. The termination circumstances which are common are long-term events of Force Majeure and Transmission System Outage caused by Force Majeure (730 days) (§§16.1(c) and (d), 16.2(b) and (c)). The Buyer's rights also arise from failures to get the Material Permits or to achieve the Guaranteed COD (§16.1(a) and (b)). The Seller has the right to terminate early if the Material Permits cannot be obtained, the penalty for which is a reduced payment of $2.50/MWh for each unit of Annual Firm Energy Amount (§§16.2(c), 16.5(a)). A general obligation of the Seller due in most, if not all, cases is the payment under §16.7 of the unrecovered part of the Transmission Network Upgrades.

The Buyer Termination Event and the Seller Termination Event have standard definitions (¶¶15,113). The effects of termination are set forth in an overly complex set of provisions (§§16.3 through 16.9) which are generally sensible and fair. In particular, the Seller's payment for most at-fault terminations is the lesser of the payment of Performance Security or the positive amount, if any, by which the Terminating Party's Economic Losses and Costs exceed its Gains.[8] This provision is likely to limit the Seller's exposure to the Performance Security since the Buyer is likely to have Gains by purchasing replacement power in place of contract power. However, it is not clear that the payment due to the Seller under §16.5(d) is adequate when the Buyer is responsible for an early breach of the EPA (e.g., an "economic breach"). A larger disincentive to the Buyer may be in order.

13. Lender Rights and Coordination

[8] It is not clear how any party can have both Gains and Losses in the termination of a single agreement.

The assignment provisions of the EPA contemplate the assignment of the EPA to a lender for financing purposes and require in such a case that the lender, the Seller and the Buyer enter into a Consent Agreement substantially in the form attached as Appendix 7 (§§17.1, 17.3). The Form of Consent in Appendix 7 includes many of the features that lenders require in such consent agreements, such as notice and extra time before the Buyer can exercise its many rights to terminate the EPA. However, the form is not consistent with the type of agreements most lenders prefer. With respect to Appendix 7, lenders typically want to be granted broader rights such as consent rights over EPA amendments, expanded rights to cure the Seller's defaults, including step-in rights superior to any held by the Buyer, rights to transfer to designees which can step in and perform in place of the lenders, rights to execute replacement EPAs in the event that the Seller's trustee terminates the EPA and other similar rights which are broader than the lender's Appendix 7 rights. As a result, the "required" form is likely to be a source of negotiation after the EPA is executed, introducing uncertainty into the financing process for the Sellers.

14. <u>Consequential Damages</u>.

In a provision now common in the industry, neither party owes the other consequential damages under the EPA (§13.6).

15. <u>Disposition of the Seller's Plant upon Expiration of the Term</u>.

The specimen EPA does not contain a provision to implement the interest of the Buyer in obtaining the benefits of the Seller's project after the term of the EPA expires. However, in the documentation for the 2008 Clean Power Call, the following invitation was made by BC Hydro:

> "BC Hydro may wish to acquire "residual rights" in respect of certain Projects. "Residual rights" include an option to purchase the Project assets, and/or to renew the term of the EPA, and/or other mechanisms that will secure to BC Hydro access to the legacy of the Project, the Project site and/or the Project output in perpetuity or for an extended term."

Bidders were invited to submit separate proposals which BC Hydro would consider a severable part of the bid for entering into the EPA. Under the awarded EPAs, BC Hydro received residual rights in the form of term extension options for 9 projects.

In order to address the interest of the Seller in extending its access to the power generated by the Seller's Plant, the following mechanisms and commentary are offered:

- In some other jurisdictions, bidders are more formally invited to bid either the terms of an extended power contract, including the extension of the original pricing terms or the conversion to different terms, or the basis upon which the plant would be acquired as an asset of the Seller.
- In some other jurisdictions, the terms of acquisition of the asset at expiration could include bidding a fixed price for the transfer or specifying a formula for deriving the price at the time of expiration. Formula pricing in jurisdictions with an active spot and capacity market for wholesale energy and capacity can rely upon an expert's or panel of experts' determination of the capitalized value at expiration of the net revenues from such a market. Care is still needed to specify how the discount rate is set at the time and to resolve as many algorithmic questions as possible in advance.
- With long term EPAs, bidders might be reluctant to rely upon formula pricing based on market prices since the ability to project power and capacity values accurately far in the future is seriously doubted. In any event, this power market formula pricing would not seem to be viable under present monopsony conditions in the BC Hydro market.
- Other possible formula prices for an asset transfer could be "reproduction cost new less depreciation", a standard used in many jurisdiction to obtain an estimate of the fair market value of a capital asset that is not normally traded in any market. Values can be derived using this formula but under the EPA, use of an expert panel might be advisable to cause challenging issues regarding the indices to use and the state of depreciation of the asset to be resolved collegially.
- The existence of a monopsony market creates significant risk for any Seller who rejects the idea of submitting an optional proposal for disposition of the power or asset upon expiration. Sellers should be entitled to take the risk that an economically accessible market will be in place by the time the term expires. A question will still exist whether competition was sufficient in the original

solicitation to cause the price for that risk of the Sellers to be a reasonable value for the Buyer.

- It is not common in jurisdictions with power markets that bidders would be required to offer extensions of the power contracts or transfer pricing at the end of the term. For the protection of the Seller and the Buyer in BC, however, a requirement for some option may make sense. If Sellers were required to offer both extensions and transfer pricing, and if the Buyer selected a transfer, the Seller might then acquire a right to convert the transfer price chosen to an equivalent power price over the period of the expected second term.

16. The Risk of First Nations Claims

On October 28, 2010, the Supreme Court of Canada ruled in Rio Tinto Alcan Inc. and British Columbia Hydro and Power Authority v. Carrier Sekani Tribal Council, Docket No. 33132, holding that the British Columbia Utilities Commission had the power to review, and correctly reviewed, the adequacy of First Nations consultation in the matter of the approval of the 2007 EPA between BC Hydro and Rio Tinto Alcan Inc., but the BCUC did not have the power to engage in consultation which in the future will be required when the government through BC Hydro enters into an EPA potentially affecting First Nations' interests and claims. In the latter respect, it was clear that the Court affirmed the duty of BC Hydro to consult with First Nations on future developments that may adversely affect their claims and rights, whether directly through BC Hydro's conduct or indirectly by entering into an EPA.

Based on Court of Appeal decisions in February, 2008, BC Hydro anticipated that it would have a consultation duty when entering into EPAs and introduced a new provision regarding First Nations into the specimen EPA. It appears, based solely on this provision, that BC Hydro does not itself generally plan to conduct consultation in satisfaction of its duty as a Crown corporation entering into an EPA. On the contrary, BC Hydro appears to plan to delegate the procedural aspects of the consultation duty to the third party IPP entering into the EPA with BC Hydro. This may be similar to delegations that occur between the environmental agencies and developers when environmental assessments required for the development to proceed are the governmental action which triggers the duty to consult.

Thus, Section 4.6 of the specimen EPA now addresses First Nations claims and rights. If prior to the second anniversary of Commercial Operation Date, the Buyer is subject to actual or threatened legal proceedings or a court or regulatory decision regarding potential adverse impacts on aboriginal rights arising from the EPA or project, then the Buyer can delegate any consultation requirements to the Seller and can require the Seller to take measures to prevent, mitigate, compensate or otherwise accommodate the affected First Nations. However, if the Seller is unable to adequately consult with and/or accommodate the impacted First Nations without being exposed to commercially unreasonable costs or other obligations, having regard to all other financial benefits and burdens of the EPA to the Seller over the full term of the EPA, the Seller may terminate the EPA without liability to the Buyer. Termination of the EPA may be avoided if the parties can work out an alternate solution such as an amendment of the EPA or if the Buyer withdraws the delegation of these requirements to the Seller.

This EPA provision dealing with First Nations' risks raises questions whether the risk is being managed completely and effectively. Terminating the EPA before COD or within two years after the project has entered service appears to be an incomplete solution for both the Buyer and the Seller. In the event that the EPA is terminated, the Seller will no longer receive a contracted revenue stream from BC Hydro. For BC Hydro, depending on the status of the legal proceedings and the project, there may still be a legal requirement to address the First Nations consultation and accommodation deficiencies identified in the actual or threatened legal or regulatory proceeding.

Thus, when the parties cannot reach a satisfactory solution regarding the First Nations consultation and accommodation requirements, the EPA termination appears to be the sole post-COD remedy provided. Recognizing this possibility should bring renewed attention to resolving all First Nations questions during the procurement process or the contract milestone process. Resolution of First Nations issues appears to require early and effective management.

C. Comparison of BC Hydro EPA to Power Purchase Agreements (PPA) and PPA Pricing Provisions in a Sampling of Forms in the Industry

Please see the attached appendices as follows:

- Appendix I: Hydro Quebec EPA Assessment
- Appendix II: Ontario Power Authority EPA Assessment
- Appendix III: PacifiCorp PPA Assessment
- Appendix IV: PG&E Renewable Price and Delivery Assessment
- Appendix V: Hawaiian Electric Company Renewable Price and Delivery Assessment
- Appendix VI: Summary of Price and Delivery Terms of US Renewable PPAs

Appendix I
Assessment of the Hydro Quebec Wind Energy Call for Tenders A/O 2009-02 Contract (EPA) and Related Risk Issues

The Major Allocations of Risk between Seller and Buyer in the EPA

1. Milestones, Milestone Extensions and Delays, Remedies for Milestone Failure.

This contract has a similar approval provision for the applicable regulatory agency, entitling the Supplier to terminate if the approval is not obtained in 120 days. Here the milestone events contemplate a date certain for guaranteed COD, as well as several earlier milestones for land acquisition, impact studies, permits and financing and laying foundations, each of which is a set number of months prior to the guaranteed COD. The possibility of limited interim milestone deferrals (3 months) is provided for in the EPA. Termination penalties for milestone defaults are provided for and range from $10,000 to $20,000/MWh depending on how close to the COD the default termination occurs. If the Supplier cannot obtain permits, it is not excused and a default termination with damages will ensue.

The penalty for achieving the guaranteed COD late is the per day fee of $55/MW up to a maximum of $20,000/MW of the contract capacity. Delays due to the transmission provider are excused. With regard to this event of default, however, the Distributor's right to terminate does not apply until the Supplier is given a 12-month cure period. For terminations for default prior to the COD, the damages are $10,000 or $20,000/MW, depending upon the time before the guaranteed date the termination occurs.

Security for achieving the COD ($10,000/MW) and operating the wind farm (varying from $25,000 to $40,000/MW) and dismantling the wind farm (estimated dismantling cost, due on the 10^{th} anniversary of the COD) are required under the EPA.

2. Force Majeure Exclusion of Permit Risks Affecting Milestone Performance.

As set forth and discussed below, the force majeure clause on its face seems to apply to milestone failures; however, the narrowness of the definition appears to make most common causes of permit failure outside of the definition.

3. The General Force Majeure Standard.

The force majeure clause in its entirely provides as follows:

> "The expression "force majeure" in the *contract* shall mean any event that is **unforeseeable, irresistible, and beyond a Party's control**, which causes a delay in or interrupts or prevents the total or partial performance by said Party of any or all of its obligations under the *contract*. Without limiting the generality of the foregoing, the following events constitute force majeure: war, riot, act of vandalism, rebellion, epidemic, lightning, earthquake, storm, ice storm, strike, flood, fire, explosion. **Any event caused by or resulting from an equipment breakdown, a drop in or absence of wind shall not be considered a force majeure**. Any force majeure affecting the *transmission provider* in accordance with *Hydro-Québec Open Access Transmission Tariff* which results in a total or partial reduction in the deliveries provided for in the *contract*, shall be deemed to be a force majeure invoked by the **Distributor**. The Party invoking a force majeure must notify the other Party forthwith and indicate in said notice, as precisely as possible, the effect of said force majeure on its ability to carry out its obligations under the *contract*.
>
> The obligations of a Party invoking a force majeure shall be suspended insofar as said Party is unable to act only and provided that it acts with diligence to eliminate or correct the effects of such force majeure. However, settlement of a strike shall be left to the sole discretion of the Party that encounters such difficulty. However, force majeure shall not affect the obligation to pay any amount of money owed.
>
> When a due date is established in the *contract* for fulfilling an obligation and said date cannot be met due to a force majeure, more specifically **when the *guaranteed commencement date of deliveries* or any milestone date of a *milestone event* is involved, such date shall be deferred by a period of time equivalent to the one during which the Party affected by the force majeure was unable to act**. This provision is not intended to modify the term of the *contract* provided for under Section 3.
>
> Subject to the notice in the first paragraph of this section and notwithstanding any other provisions in the *contract*, failure to fulfill an obligation due to force majeure, regardless of the Party that invokes it, shall not constitute a default hereunder and shall not result in any damages, or in any recourse for specific performance or recourse of any other nature whatsoever. In addition, the non-performance of any obligation due to a force majeure may not lead to a revision of the *contract energy* under Section 8 or the application of damages or penalties under Sections 29, 30, 31 and 32."
> EPA Section 34 (emphasis added.)

While the emphasized language dealing with milestones does extend force majeure protection, without apparent limitation as to its duration, to the Supplier in its efforts to meet milestones, the narrowness of the definition itself appears to make this application of force majeure unlikely to be of significant benefit. For example, a denial of permits or a failure to obtain permits in a timely fashion is not likely to be seen as "unforeseeable, irresistible and beyond a Party's control". While doubt does remain as to the application of these terms to the general permit failure, it seems that the treatment of permit failure more likely to have been intended is that provided in another provision which allows the Supplier to give notice and to accept a default termination of the EPA. In this regard, Section 5.3 provides as follows:

> If, on the milestone date of *milestone event* 3, all of the decisions have not yet been rendered by the competent regulatory authorities regarding the certificate of authorization or any permit, licence or authorization under *milestone event* 3 (ii), the **Supplier** may inform the **Distributor** of its decision to not proceed with the construction of the *wind farm* if all of said decisions have not been rendered by the regulatory authorities within sixty (60) days of said notice. Upon receipt of said notice, the **Distributor** shall transmit to the **Supplier** prior notice of termination of sixty (60) days under Section 35.1(f) and if all of said decisions are not rendered by the regulatory authorities prior to the expiration of said prior notice period, the *contract* shall be terminated by the **Distributor,** Section 35.5 shall apply, and the **Distributor** shall have no other recourse against the **Supplier**.
> EPA Section 5.3

Also note in the definition that includes the following language emphasized above:
"Any event caused by or resulting from an equipment breakdown, a drop in or absence of wind shall not be considered a force majeure." Clearly, the absence of wind is excluded from the clause.

4. <u>Force Majeure and Change in Law Risks</u>.

The Supplier takes the risk that the permits needed for the wind farm will remain in effect and that the Supplier can operate in accordance with applicable laws and regulations as such may be amended.

5. <u>The General Risk of Events or Circumstances Outside the Control of the Seller</u>.

The force majeure clause has a narrow definition, requiring that events be unforeseeable, irresistible and beyond the control of the Party. Many events that frustrate the Supplier's performance will be seen to fail one or more of these criteria, particularly since greater than reasonable efforts would be expected on the part of the Supplier to prevent the interference in its performance.

6. Capital Cost Escalation.

No provision of the EPA appears to contemplate changes in the contract pricing due to the common causes for an increase in the total cost of a wind farm such as development delays, changes in the expected price of the turbines or the construction contract, currency risks and the like.

7. Power Pricing and Price Escalation.

A single power price is provided for that explicitly compensates for capacity and energy value. The eligible energy price applies each year up to an amount equal to 120% of the contract energy. How the price may vary year to year is not set forth in the model EPA. Excess amounts in the second year of excess and thereafter are priced based on a fixed price ($26.75) adjusted by the CPI. Energy made available is also paid for at the excess price after an amount equal to 24 hours of delivery at the Contract Capacity.

Reimbursement provisions exist for the costs of the collector system and the transformation substation equipment incurred by the Supplier up to maximum amounts which are coordinated with payments that the transmission provider may make under the interconnection agreement. If the contract is terminated by the Distributor, then these reimbursements are re-payable.

8. Energy Delivery Requirements, Shortfalls and Replacement Power Costs.

The Supplier is obligated to deliver each year an amount of contract energy set by the Supplier and energy made available but not taken by the Distributor is counted against the obligation. The Distributor may refuse delivery under defined conditions that involve some failure of the Supplier. Amounts undelivered in such cases are subject to damages under the general damage provision. That provision compares a three-year rolling average of eligible energy, energy made available and energy not received but for which damages are paid by the Distributor to the Supplier for such failure to receive (force majeure energy is also credited in this calculation) to 95% of the contract energy. The Supplier is obligated to pay damages for the difference if any in amount which is the greater of $2/MWh or a cover damages formula based on NY ISO zonal (HQ 323601) price for Locational Based Marginal Price plus $6/MWh. When delivery cannot be taken by the transmission provider, the quantities not taken are credited as energy made available except where the interconnection has been suspended or a force majeure has been declared by the transmission company. Curtailments by the Distributor also result in energy made available.

The Supplier is exposed to a potential reduction of the contract energy if after 60 months, in any annual period, the sum of the eligible energy and the energy made available is less than the contract energy. The Distributor can then reset the contract energy to an amount that can reasonably be maintained based on performance back to the COD. Damages are due based on the extent of the revision for each MW of the contract capacity evaluated at $25,000 per MW in the first ten years and $40,000 thereafter. No increase in the contract energy can thereafter occur even if justified by improving performance.

9. Operational Performance Standards.

In addition to routine and customary operational standards, Suppliers here are required to dismantle the wind farm within 12 months of the end of the contract. It is not clear whether this applies to a premature termination when the facility possesses continuing commercial abilities. During the term, the dismantling obligation applies on a turbine by turbine basis for any that are unable to generate on a commercial basis for 24 months.

10. The Risk of Interruption or Price Escalation of Fuel Supply or Energy Source.

For this wind farm EPA, the price of the energy source is not applicable. However, the force majeure clause, as indicated above, explicitly excludes the absence of wind from its definition.

11. Events of Default, Cure and Termination Rights.

For terminations for default prior to the COD, the damages are $10,000 or $20,000/MW, depending upon the time before the guaranteed date the termination occurs. Amounts ranging from $25,000 to $40,000/MW apply for terminations that occur after the COD. In each event, the Distributor is required to send notice to Lenders and Lenders possess rights to cure the defaults in the time periods applicable to the Supplier to effect a cure and take over the contract, as well as rights to assign the EPA to third parties who can cure the defaults and continue the contract in place of the Supplier.

The damage amounts specified are the only compensation due, apart from the obligation to re-pay amounts in connection with the interconnection.

The EPA appears not to have a blanket default clause entitling the non-defaulting party to terminate in the event of a material default not otherwise specified in the defined events of default.

12. Lender and Community Rights and Coordination

The EPA contains provisions which are not commonly seen that require provincial content to the equipment. Other provisions contemplate required ownership by community or aboriginal interests.

The Supplier is required to cause its Lender to inform the Distributor of any default in the financing agreements. Lenders exercising their rights to the wind farm are required to observe certain requirements regarding the community's interest in the wind farm. The Distributor retains approval authority, subject to not being unreasonably withheld, over the change of ownership of the wind farm.

13. Consequential Damages.

The EPA lacks a provision on consequential damages; however, a provision makes the stipulated damage provision exclusive compensation, suggesting that consequential damages are not intended under the EPA.

14. Disposition of the Seller's Plant upon Expiration of the Term.

The Supplier has an obligation to dismantle the wind farm at the end of the contract.

15. The Risk of First Nations Claims

There is no consultation or accommodation provision in the EPA. It does, however, appear that the participation of aboriginal interests in the ownership of the wind farms was contemplated.

Appendix II
Assessment of the Ontario Power Authority Renewable Energy Supply III Contract (EPA) and Related Risk Issues

The Major Allocations of Risk between Seller and Buyer in the EPA

1. Milestones, Milestone Extensions and Delays, Remedies for Milestone Failure.

The Supplier acknowledges that time is of the essence with respect to all Milestone Events, but liquidated damages in the amount of $50/MW per day are payable only for the Financial Closing (with a maximum of 90 days of penalties) and $150/MW per day for the Commercial Operation deadlines (with a maximum of 545 days of penalties). Additional damages are due if one year after the Commercial Operation, deemed to be achieved when 90% of Contract Capacity is in service, the Supplier has failed to reach the 100% mark. The rate is again $150/MW, with the maximum duration again at 545 days.

On the other hand, operation of the broad force majeure clause, which includes specifically the failure to obtain permits and force majeure events which delay milestone performance, excuses the affected party from any liability or damages to the other party in respect of or relating to the force majeure.

Subject to the other provisions of the EPA, failure to achieve the COD one year after the guaranteed date is a defined Supplier Event of Default unless the Supplier has paid all liquidated damages then due and the Buyer holds all of the needed Completion and Performance Security. At the 18-month mark after the guaranteed date, if the COD has not occurred, or if less than 100% of the Contract Capacity is not available at the 18-month mark after the Full Operation Date, a Supplier Event of Default exists. Supplier Events of Default entitle the Buyer to terminate and collect as liquidated damages all of the security. Furthermore, a board residual rights provision exists in the EPA making the termination and payment of all amounts due under the EPA non-exclusive remedies. In this regard, either party in such an event is entitled to all other rights and remedies available at law or in equity. Broad residual remedies provisions are not uncommon in the industry.

2. Force Majeure Inclusion of Permit Risks Affecting Milestone Performance.

As set forth above, permit failure is included specifically as an event of force majeure, extending applicable milestone deadlines and creating in the Supplier a right after one year of delay in achieving the COD to a “liability-free” termination. Please refer to Attachment B.1 to this Appendix II for a copy of the applicable force majeure provisions.

3. The General Force Majeure Standard.

The force majeure clause in this EPA is broad and flexible and grants relief for several common problems that IPPs experience in developing and operating their plants. The provisions are reproduced in full in Attachment B.1 to this assessment. With respect to delays lasting more than a year in the COD which are caused by an inability to obtain any permit, impact assessment, license, certificate and the like, the Supplier is granted a “liability-free” right to terminate the EPA. If the force majeure event caused a delay in the COD of more than 24 months, either party has the same “liability-free” right to terminate. More generally, force majeure events that delay the achievement of any milestone event result in the extension of the milestone deadline by the reasonable period of the delay.

Force majeure exclusions do include (i) the inability to procure or maintain a fuel supply and (ii) events caused by lack of funds or other financial cause. As indicated above, the inclusions specifically capture permit failures. In addition, unanticipated maintenance or outages after the COD under specified conditions are also explicitly included as force majeure events.

4. Force Majeure and Change in Law Risks.

No provision in the force majeure clause or elsewhere in the EPA excuses performance for a general change in law. However, in the clause, an order, judgment, legislation, ruling or direction by Governmental Authorities restraining a party is a qualified event of force majeure as long as the party has not applied for or assisted in the application for the restriction and has used Commercially Reasonable Efforts to oppose the restriction. It is at least in theory possible this provision would apply to First Nations claims resulting in official restriction on the Supplier’s project.

Although performance appears not to be excused in the event of a change in law, the EPA contains a broad provision, which is not common to the industry, that provides compensation to the Supplier for the extra costs and diminution of revenues associated with certain "discriminatory" legislation (or orders-in-council or regulations) coming into effect on or after the Supplier's proposal was submitted. Such a circumstance is defined as "Discriminatory Action" (where the effect of the legislation is principally borne by Supplier(s)) and the entire section treating such action is reproduced here as Attachment B.2 to this Appendix II. If a Discriminatory Action occurs, compensation from the Buyer is due in the amount of the increase in costs incurred by the Supplier as a result of the action and in the amount of the diminution in the net present value of expected net revenues from the Contract Facility.

5. The General Risk of Events or Circumstances Outside the Control of the Supplier.

Although fuel supply risk and performance failures related to financial difficulty are risks retained by the Supplier, the broad force majeure clause rests upon a definition of force majeure that captures all events which are beyond the reasonable control of the affected party. In this regard, greater than reasonable efforts to control an event which is making the party unable to perform are not required in order to qualify for force majeure. A definition of this sort is not uncommon in many jurisdictions.

6. Capital Cost Escalation.

Other than the change in law risk discussed herein, no evidence exists in the EPA that the Supplier is granted any increase in its Contract Price or any other relief in the event that the many events causing the Supplier to experience higher costs to develop the Contract Facility are experienced.

7. Power Pricing and Price Escalation.

The Buyer agrees to pay for the Monthly Delivered Energy at the Contract Price. The Supplier, who will receive payments from the IESO, agrees to offset those IESO payments to the extent of the Hourly Ontario Energy Price (HOEP) and to transfer to the Buyer amounts received for the sale of Future Contract Related Products from the IESO Markets. The Contract Price is broken into a 15% Indexed Portion which adjusts with the CPI, and the remaining Unindexed Portion which is subject to no indexation.

8. Energy Delivery Requirements, Shortfalls and Replacement Power Costs

The EPA appears to have no minimum delivery requirements, no calculation of delivery shortfalls and no provision providing for the payment of replacement power costs. The pricing provisions assure the Supplier that its market revenues received from the IESO will be evened out and that net receipts should be at the Contract Price, similar to a Contract for Differences. Payment is the incentive for performance and the Buyer appears not to be concerned with the prospect that replacement power would exceed in cost power supplied under the EPA.

9. Operational Performance Standards.

Typical provisions require the operation of the Contract Facility in accordance with defined Good Engineering and Operating Procedures. The Supplier is also required to meet all applicable requirements of the IESO Market Rules, the Transmission System Code, The Connection Agreement and all other Laws and Regulations. The Supplier is required to register itself with the IESO as a "Registered Market Participant" and as a "Generator" and the settlement of Market Settlement Charges takes place directly between the Supplier as the "Metered Market Participant" and the IESO. Any costs incurred by the Supplier acting as such a participant are the responsibility of the Supplier.

The operating standards are customary and make reference to Good Engineering and Operating Practices, which are defined, as well as all applicable requirements of the IESO Market Rules, the Transmission System Code and the Connection Agreement and other Laws and Regulations.

Both Parties are obligated to perform their obligations in accordance with all Laws and Regulations, which are defined in such a way to be interpreted to mean "as in effect at the time". All permits and consents from Governmental Authorities are also required, including all licensing as required by the Ontario Energy Board. The Supplier is required to register as specified in the IESO Market Rules as a "Registered Market Participant" and as a "Generator". Settlements of Market Settlement Charges are the responsibility of the Supplier.

Completion and Performance Security is due in escalating amounts starting on the date the EPA is delivered and no event of force majeure operates to extend the day for each escalation. Escalation ranges from $20,000/MW to $50,000/MW before declining after the COD.

10. <u>The Risk of Interruption or Price Escalation of Fuel Supply or Energy Source</u>.

The Supplier is obligated to use Commercially Reasonable Efforts to maintain fuel supply contracts that are necessary, if any, for proper operation.

11. <u>Events of Default, Cure and Termination Rights</u>.

The blanket default clause provides for an extension of the normal 15 day cure period for another 15 days, a total of 30 days which may be insufficient to cure many defaults. When the defined default involves the failure to hold a necessary permit or license, the cure period is only 30 days, extendable for another 30 days. For a cross default under loan agreements, the time to cure is 15 days, extendable for another 15 days. The events of default for the COD Milestone Date is one year after that date; however, the right to terminate does not then apply if liquidated damages are fully paid up. The right to terminate then arises 18 months after the deadline, and again, the right arises 18 months after the Full Operation Date if less than 100% of Contract Capacity is available. When a Supplier Event of Default results in a pre-COD termination, the Supplier must pay as liquidated damages all of the Completion and Performance Security, which amounts are made exclusive for such pre-COD terminations. On the other hand, if the termination is after the COD, the Buyer can retain security and in addition, can pursue other remedies available at law in equity or otherwise.

Buyer Events of Default have similar definitions, cure periods and consequences as the Supplier Events of Default. The 15-day blanket default cure period for the Buyer may not be as threatening to the Buyer as to the Supplier since the duties of the Buyer are relatively easier to cure in comparison to the Supplier which is operating a generator.

Rights to terminate apply to Supplier Events of Default and Buyer Events of Default. When the Buyer terminates, the retention of the Completion and Performance Security constitutes liquidated damages which are then specifically made non-exclusive. For either party, in a broad residual rights provision, all remedies at law or in equity are available after a termination for fault.

12. Lender Rights and Coordination.

The EPA contains extensive treatment of the relationship of secured lenders to the Buyer and the Supplier. Lenders are entitled to notice and an opportunity to cure, including extra time to take possession of the Contract Facility if necessary to effect a cure. The provisions include rights that the Buyer possesses relative to the lenders which are commonly referred to as non-disturbance rights. The latter rights limit the lenders so that a lender exercising its rights to foreclose or otherwise obtaining possession of the Contract Facility becomes bound, in place of the Supplier, to perform the Supplier's obligations under the EPA. Many lenders disfavor such limitations. In general, the attempt of these provisions to make the lenders' rights subject to the provisions of the EPA will likely result in delays in the financing as lenders attempt to amend the EPA to include provisions more flexible to the lenders.

13. Consequential Damages.

Neither party is responsible for consequential damages under the EPA. This is customary treatment of consequential damages in such industry agreements.

14. Disposition of the Supplier's Plant upon Expiration of the Term.

The term of the EPA is 20 years and neither party has a right to extend or renew the Term except as agreed by the parties.

15. The Risk of First Nations Claims.

As a condition subsequent to the EPA, the Supplier must provide the Buyer with the Crown Letter which is the response of the Crown to the Supplier's request for information regarding the duty to consult Aboriginal peoples in relation to the Contract Facility. If the Supplier receives Crown Letter "B", then within 90 days of the EPA, or such other date as agreed to, the Supplier must supply the Crown Agreement between the Crown and the Supplier respecting the delegation of procedural aspects of the Crown's duty to consult in relation to the Contract Facility. Without the Crown Agreement the construction is not allowed to begin.

Attachment B.1 of Appendix II

ARTICLE 11
FORCE MAJEURE
(Emphasis added.)

Section 11.1 Effect of Invoking Force Majeure

(a) If, by reason of Force Majeure:

(i) the Supplier is unable to make available all or any part of the Contract Capacity or is unable to deliver Electricity from the Contract Facility;

(ii) all or any part of the Contract Energy cannot be received at or transmitted or distributed from the Delivery Point (and notwithstanding whether the Buyer may be able to otherwise cause all or any part of the Contract Energy to be received at the Delivery Point or to be transmitted or distributed from the Delivery Points); or

(iii) either Party is unable, wholly or partially, to perform or comply with its other obligations (other than payment obligations) hereunder, including the **Supplier being unable to achieve a Milestone Event by the relevant Milestone Date, or the Supplier not achieving Commercial Operation on or before the date which is one (1) year or eighteen (18) months after the Milestone Date for Commercial Operation, as applicable**;

then the Party so affected by Force Majeure shall be excused and relieved from performing or complying with such obligations (other than payment obligations) and shall not be liable for any liabilities, damages, losses, payments, costs, expenses (or Indemnifiable Losses, in the case of the Supplier affected by Force Majeure) to, or incurred by, the other Party in respect of or relating to such Force Majeure and such Party's failure to so perform or comply during the continuance and to the extent of the inability so caused from and after the invocation of Force Majeure.

(b) A Party shall be deemed to have invoked Force Majeure with effect from the commencement of the event or circumstances constituting Force Majeure when that Party gives to the other Party prompt notice, written or oral (but if oral, promptly confirmed in writing) of the effect of the Force Majeure and reasonably full particulars of the cause thereof, in substantially the form as set forth in Exhibit L, provided that such notice shall be given as follows: (i) within ten (10) Business Days of the date that the Party invoking Force Majeure knew or ought to have known that the event or circumstances constituting Force Majeure could have a Material Adverse Effect on the critical path of the project schedule for the development and construction of the Contract Facility where the event or circumstances constituting Force Majeure occur prior to Commercial Operation; or (ii) within ten (10) Business Days of the commencement of the event or circumstances constituting Force Majeure where the event or circumstances constituting Force Majeure occur on or after Commercial Operation. If the effect of the Force Majeure and full particulars of the cause thereof cannot be reasonably determined within such ten (10) Business Day period, the Party invoking Force Majeure shall be allowed a further ten (10) Business Days (or such longer period as the Parties may agree in writing) to provide such full particulars in substantially the form as set forth in Exhibit L to the other Party.

(c) The Party invoking Force Majeure shall use Commercially Reasonable Efforts to remedy the situation and remove, so far as possible and with reasonable dispatch, the Force Majeure, but settlement of strikes, lockouts and other labour disturbances shall be wholly within the discretion of the Party involved.

(d) The Party invoking Force Majeure shall give prompt written notice of the termination of the event of Force Majeure provided that such notice shall be given within ten (10) Business Days of the termination of the event or circumstances constituting Force Majeure.

(e) Nothing in this Section 11.1 shall relieve a Party of its obligations to make payments of any amounts that were due and owing before the occurrence of the Force Majeure or that otherwise may become due and payable during any period of Force Majeure.

(f) **If an event of Force Majeure causes the Supplier to not achieve a Milestone Event by the relevant Milestone Date, or to not achieve Commercial Operation on or before the date which is one (1) year after the Milestone Date for Commercial Operation, as applicable, then such Milestone Date shall be extended for such reasonable period of delay directly resulting from such Force Majeure event. After the Commercial Operation Date, an event of Force Majeure shall not extend the Term**.

g) **if an event of Force Majeure described in *Section 11.3(i)* [9]has delayed the Commercial Operation Date by more than 365 days after the original Milestone Date (prior to any extension pursuant to Section 11.1(f)) set out for attaining Commercial Operation of the Contract Facility**, then notwithstanding anything in this Agreement to the contrary, while the delay that is a result of the event of Force Majeure is continuing, **the Supplier at its sole option may terminate this Agreement upon notice to the Buyer and without any costs or payments of any kind to either Party, and all security shall be returned forthwith**.

(h) **If, by reason of Force Majeure, the Commercial Operation Date is delayed by more than twenty-four (24) months after the original Milestone Date for Commercial Operation, prior to any extension pursuant to Section 11.1(f),** then notwithstanding anything in this Agreement to the contrary, **either Party may terminate this Agreement upon notice to the other Party and without**

[9] This is more likely Section 11.3(h) which relates to permit failures prior to the COD.

any costs or payments of any kind to either Party, and all security shall be returned forthwith.

(i) If, by reason of Force Majeure, the **Supplier is unable to perform or comply with its obligations (other than payment obligations) hereunder for more than an aggregate of thirty-six (36) months in any sixty (60) month period during the Term, then either Party may terminate this Agreement upon notice to the other Party without any costs or payments of any kind to either Party, except for any amounts that were due or payable by a Party hereunder up to the date of termination, and all security shall be returned forthwith**.

(j) Intentionally Deleted.

(k) Intentionally Deleted.

(l) Intentionally Deleted.

Section 11.2 Exclusions

A Party shall not be entitled to invoke Force Majeure under this Article 11, nor shall it be relieved of its obligations hereunder in any of the following circumstances:

a) if and to the extent the Party seeking to invoke Force Majeure has caused the applicable event of Force Majeure by its fault or negligence;

(b) **if and to the extent the Party seeking to invoke Force Majeure because it is unable to procure or maintain any fuel supply to be utilized by the Contract Facility;**

(c) if and to the extent the Party seeking to invoke Force Majeure has failed to use Commercially Reasonable Efforts to prevent or remedy the event of Force Majeure and remove, so far as possible and within a reasonable time period, the Force Majeure (except in the case of strikes, lockouts and other labour disturbances, the settlement of which shall be wholly within the discretion of the Party involved);

(d) if and to the extent that the Supplier is seeking to invoke Force Majeure because it is able to sell any of the Contract Energy on more advantageous terms to a thirdparty buyer;

(e) if and to the extent that the Party seeking to invoke Force Majeure because of arrest or restraint by a Governmental Authority, such arrest or restraint was the result of a breach or failure to comply by such Party of Laws and Regulations;

(f) **if the Force Majeure was caused by a lack of funds or other financial cause**; or

g) if the Party invoking Force Majeure fails to comply with the notice provisions in Section 11.1(b) or Section 11.1(d).

Section 11.3 Definition of Force Majeure

For the purposes of this Agreement, the term "**Force Majeure**" means any act, event, cause or condition that prevents a Party from performing its obligations (other than payment obligations) hereunder, **that is beyond the affected Party's reasonable control**[10], and shall include:

(a) acts of God, including extreme wind, ice, lightning or other storms, earthquakes, tornadoes, hurricanes, cyclones, landslides, drought, floods and washouts;

(b) fires or explosions;

(c) local, regional or national states of emergency;

(d) strikes and other labour disputes (other than legal strikes or labour disputes by employees of such Party or a third-party invoking Force Majeure, unless such strikes or other labour disputes are the result or part of a general industry strike or labour dispute);

(e) Intentionally Deleted.

(f) civil disobedience or disturbances, war (whether declared or not), acts of sabotage, blockades, insurrections, terrorism, revolution, riots or epidemics;

(g) subject to Section 11.2(e), an order, judgment, legislation, ruling or direction by Governmental Authorities restraining a Party, provided that the affected Party has not applied for or assisted in the application for and has used Commercially Reasonable Efforts to oppose said order, judgment, legislation, ruling or direction;

(h) **any inability to obtain, or to secure the renewal or amendment of, any permit, certificate, impact assessment, licence or approval of any Governmental Authority, or Transmitter required to perform or comply with any obligation under this Agreement,** unless the revocation or modification of any such necessary permit, certificate, impact assessment, licence or approval was caused by the violation of the terms thereof or consented to by the Party invoking Force Majeure; and

(i) **any unanticipated maintenance or outage affecting the Contract Facility**:

> (i) which is not identified in the Supplier's then current schedule of planned outages submitted to the IESO or the Buyer, as the case may be, in advance of the occurrence of an event of Force Majeure referred to in this Section 11.3; and

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[10] There is no "unforeseeability" condition that prevents foreseeable events from qualifying as force majeure.

(ii) **which results directly from, or is scheduled or planned directly as a consequence of, an event of Force Majeure referred to in this Section 11.3**, **or which results from a failure of equipment that prevents the Contract Facility from producing Electricity**, provided that:
(A) notice of the unanticipated maintenance or outage is provided to the Buyer by the Supplier as soon as reasonably possible (or, if applicable, concurrently with the notice in respect thereof provided to the IESO or as soon as reasonably possible thereafter) but, in any event, within ten (10) Business Days thereof;
(B) the Supplier provides notice to the Buyer immediately, or as soon as reasonably possible thereafter, upon receipt from the IESO of advance acceptance or other proposed scheduling or approval of such maintenance or outage, if such approval is required to be obtained from the IESO;
(C) the Supplier provides timely updates to the Buyer of the commencement date of the maintenance or outage and, where possible, provides seven (7) days advance notice of such date;
(D) **the unanticipated maintenance or outage is commenced within one Hundred and twenty (120) days of the commencement of the occurrence of the relevant event of Force Majeure**; and
(E) the Supplier schedules the unanticipated maintenance or outage in accordance with Good Engineering and Operating Practices.

(j) Intentionally Deleted.

For greater certainty, nothing in Section 11.3(i) shall be construed as limiting the duration of an event of Force Majeure. Each Party shall resume its obligations as soon as the event of Force Majeure has been overcome.

Attachment B.2 of Appendix II

ARTICLE 13
DISCRIMINATORY ACTION

Section 13.1 Discriminatory Action

A "**Discriminatory Action**" shall occur if:

(a)
(i) the Legislative Assembly of Ontario causes to come into force any statute that was introduced as a government bill in the Legislative Assembly of Ontario or causes to come into force or makes any order-in-council or regulation first having legal effect on or after the date of the submission of the Proposal; or

(ii) the Legislative Assembly of Ontario directly or indirectly amends this Agreement without the agreement of the Supplier;

(b) the effect of the action referred to in Section 13.1(a):

(i) is borne principally by the Supplier; or

(ii) is borne principally by the Supplier and one or more Other Suppliers who have a RES Contract or another bilateral arrangement with the Buyer similar in nature to this Agreement; and

(c) such action increases the costs that the Supplier would reasonably be expected to incur under this Agreement in the generation and delivery of the Contract Energy and/or Future Contract Related Products or adversely affects the revenues of the Supplier from the Contract Facility, except where such action is in response to any act or omission on the part of the Supplier that is contrary to Laws and Regulations (other than an act or omission rendered illegal by virtue of such action) or such action is permitted under this Agreement. Despite the preceding sentence, none of the following shall be a Discriminatory Action:

(i) Laws and Regulations of general application, including an increase of Taxes of general application, or any action of the Government of Ontario pursuant thereto;

(ii) any such statute that prior to five (5) Business Days prior to the date of the submission of the Proposal in accordance with Renewable Energy Supply III RFP:

> (A) has been introduced as a Bill in the Legislative Assembly of Ontario in a similar form as such statute takes when it has legal

effect, provided that any amendments made to such Bill in becoming such statute do not have a Material Adverse Effect on the Supplier; or

(B) has been made public in a discussion or consultation paper, press release or announcement issued by the Government of Ontario that appeared on the website of the Government of Ontario, provided that any amendments made to such public form, in becoming such statute, do not have a Material Adverse Effect on the Supplier;

(iii) any of such regulations that prior to five (5) Business Days prior to the date that the Supplier submitted its Proposal in accordance with the Renewable Energy Supply III RFP:

(A) have been published but by the terms of such regulations come into force on or after five (5) Business Days prior to date that the Supplier submitted its Proposal in accordance with the Renewable Energy Supply III RFP; or

(B) have been referred to in a press release issued by the Government of Ontario that appeared on the website of the Government of Ontario provided that any amendments made to such regulations in coming into force do not have a Material Adverse Effect on the Supplier.

Section 13.2 Consequences of Discriminatory Action

If a Discriminatory Action occurs, the Supplier shall have the right to obtain, without duplication, compensation (the "**Discriminatory Action Compensation**") from the Buyer for:

(a) the amount of the increase in the costs that the Supplier would reasonably be expected to incur in the delivery of the Contract Energy and/or Future Contract Related Products as a result of the occurrence of such Discriminatory Action, commencing on the first day of the first calendar month following the date of the Discriminatory Action and ending at the expiry of the Term, but excluding the portion of any costs charged by a Person who does not deal at Arm's Length with the Supplier that is in excess of the costs that would have been charged had such Person been at Arm's Length with the Supplier; and

(b) the amount by which (i) the net present value of the net revenues from the Contract Facility that are forecast to be earned by the Supplier during the period of time commencing on the first day of the first calendar month following the date of the Discriminatory Action and ending at the expiry of the Term, exceeds (ii) the net present value of the net revenues from the Contract Facility that are forecast to be earned by the Supplier during the period of time commencing on the first day of the first calendar month following the date of the Discriminatory

Action and ending on the expiry of the Term, taking into account the occurrence of the Discriminatory Action and any actions that the Supplier should reasonably be expected to take to mitigate the effect of the Discriminatory Action, such as by mitigating operating expenses and normal capital expenditures of the business of the generation and delivery of the Contract Energy and/or Future Contract Related Products by the Contract Facility.

Section 13.3 Notice of Discriminatory Action

(a) In order to exercise its rights in the event of the occurrence of a Discriminatory Action, the Supplier must give a notice (the "**Preliminary Notice**") to the Buyer within sixty (60) days after the date on which the Supplier first became aware (or should have been aware, using reasonable due diligence) of the Discriminatory Action stating that a Discriminatory Action has occurred. Within sixty (60) days after the date of receipt of the Preliminary Notice, the Supplier must give another notice (the "**Notice of Discriminatory Action**"). A Notice of Discriminatory Action must include:

(i) a statement of the Discriminatory Action that has occurred;

(ii) details of the effect of the said occurrence that is borne by the Supplier;

(iii) details of the manner in which the Discriminatory Action increases the costs that the Supplier would reasonably be expected to incur in the generation and delivery of the Future Contract Related Products or adversely affects the revenues of the Supplier; and

(iv) the amount claimed as Discriminatory Action Compensation and details of the computation thereof.

The Buyer shall, after receipt of a Notice of Discriminatory Action, be entitled, by notice given within thirty (30) days after the date of receipt of the Notice of Discriminatory Action, to require the Supplier to provide such further supporting particulars as the Buyer considers necessary, acting reasonably.

(b) If the Buyer wishes to dispute the occurrence of a Discriminatory Action, the Buyer shall give a notice of dispute (the "**Notice of Dispute**") to the Supplier, stating the grounds for such dispute, within thirty (30) days after the date of receipt of the Notice of Discriminatory Action or within thirty (30) days after the date of receipt of the further supporting particulars, as applicable.

(c) If neither the Notice of Discriminatory Action nor the Notice of Dispute has been withdrawn within thirty (30) days after the date of receipt of the Notice of Dispute by the Supplier, the dispute of the occurrence of a Discriminatory Action shall be submitted to mandatory and binding arbitration in accordance with Section 16.2 without first having to comply with Section 16.1.

(d) If the Buyer does not dispute the occurrence of a Discriminatory Action or the amount of Discriminatory Action Compensation claimed in the Notice of Discriminatory Action, the Buyer shall pay to the Supplier the amount of Discriminatory Action Compensation claimed within sixty (60) days after the date of receipt of the Notice of Discriminatory Action. If a Notice of Dispute has been given, the Buyer shall pay to the Supplier the Discriminatory Action Compensation Amount determined in accordance with Section 13.3(e) not later than sixty (60) days after the later of the date on which the dispute with respect to the occurrence of a Discriminatory Action is resolved and the date on which the Discriminatory Action Compensation Amount is determined.

(e)
(i) If the Buyer wishes to dispute the amount of the Discriminatory Action Compensation, the Buyer shall give to the Supplier a notice (the "**Discriminatory Action Compensation Notice**") setting out an amount that the Buyer proposes as the Discriminatory Action Compensation (the "**Discriminatory Action Compensation Amount**"), if any, together with details of the computation. If the Supplier does not give notice (the "**Supplier Non-acceptance Notice**") to the Buyer stating that it does not accept the Discriminatory Action Compensation Amount proposed within thirty (30) days after the date of receipt of the Discriminatory Action Compensation Notice, the Supplier shall be deemed to have accepted the Discriminatory Action Compensation Amount so proposed. If the Supplier Non-acceptance Notice is given, the Buyer and the Supplier shall attempt to determine the Discriminatory Action Compensation Amount through negotiation, and any amount so agreed in writing shall be the Discriminatory Action Compensation Amount. If the Buyer and the Supplier do not agree in writing upon the Discriminatory Action Compensation Amount within sixty (60) days after the date of receipt of the Supplier Non-acceptance Notice, the Discriminatory Action Compensation Amount shall be determined in accordance with the procedure set forth in Section 13.3(e)(ii) and Sections 16.1 and 16.2 shall not apply to such determination.

(ii) If the negotiation described in Section 13.3(e)(i) does not result in an agreement in writing on the Discriminatory Action Compensation Amount, either the Buyer or the Supplier may, after the later of (A) the date on which a dispute with respect to the occurrence of a Discriminatory Action is resolved and (B) the date of the expiry of a period of thirty (30) days after the date of receipt of the Supplier Non-acceptance Notice, by notice to the other require the dispute to be resolved by arbitration as set out below. The Buyer and the Supplier shall, within thirty (30) days after the date of receipt of such notice of arbitration, jointly appoint a valuator to determine the Discriminatory Action Compensation Amount. The valuator so appointed shall be a duly qualified business valuator where the individual responsible for the valuation has not less than ten (10) years' experience in the field of business valuation. If the Buyer and the Supplier are unable to agree upon a valuator within such period, the Buyer and the Supplier shall jointly make application (provided that if a Party does not participate in such application, the other Party may make application alone) under the *Arbitration Act, 1991* (Ontario) to a judge of the Superior Court of Justice to appoint a valuator, and the provisions of the *Arbitration Act, 1991* (Ontario) shall govern such appointment. The valuator shall determine the Discriminatory Action Compensation Amount within sixty (60) Business Days after the date of his or her appointment. Pending a decision by the valuator, the Buyer and the Supplier shall share equally, and be responsible for their respective shares of, all fees and expenses of the valuator. The fees and expenses of the valuator shall be paid by the non-prevailing Party. "**Prevailing Party**" means the Party whose determination of the Discriminatory Action Compensation Amount is most nearly equal to that of the valuator's determination. The Supplier's and the Buyer's respective determinations of the Discriminatory Action Compensation Amount shall be based upon the Notice of Discriminatory Action and the Discriminatory Action Compensation Notice, as applicable.

(iii) In order to facilitate the determination of the Discriminatory Action Compensation Amount by the valuator, each of the Buyer and the Supplier shall provide to the valuator such information as may be requested by the valuator, acting reasonably, and the Supplier shall permit the valuator and the valuator's representatives to have reasonable access during normal business hours to such information and to take extracts therefrom and to make copies thereof.

(iv) The Discriminatory Action Compensation Amount as determined by the valuator shall be final and conclusive and not subject to any appeal.

(f) Any amount to be paid under Section 13.3(d) shall bear interest at a variable nominal rate per annum equal on each day to the Interest Rate then in effect from the date of receipt of the Notice of Discriminatory Action to the date of payment.

(g) Payment of the Discriminatory Action Compensation and interest thereon by the Buyer to the Supplier shall constitute full and final satisfaction of all amounts that may be claimed by the Supplier for and in respect of the occurrence of the Discriminatory Action and, upon such payment, the Buyer shall be released and forever discharged by the Supplier from any and all liability in respect of such Discriminatory Action.

Section 13.4 Right of the Buyer to Remedy or Cause to be Remedied a Discriminatory Action

If the Buyer wishes to remedy or cause to be remedied the occurrence of a Discriminatory Action, the Buyer must give notice to the Supplier within thirty (30) days after the later of the date of receipt of the Notice of Discriminatory Action and the date of the receipt by the Buyer of the further supporting particulars referred to in Section 13.3(b). If the Buyer gives such notice, the Buyer must remedy or cause to be remedied the Discriminatory Action within one hundred and eighty (180) days after the date of receipt of the Notice of Discriminatory Action or, if a Notice of Dispute has been given, within one hundred and eighty (180) days after the date of the final award pursuant to Section 16.2 to the effect that a Discriminatory Action occurred. If the Buyer remedies or causes to be remedied the Discriminatory Action in accordance with the preceding sentence, the Supplier shall have the right to obtain, without duplication, the amount that the Supplier would have the right to claim in respect of that Discriminatory Action pursuant to Section 13.2, adjusted to apply only to the period commencing on the first day of the first calendar month following the date of the Discriminatory Action and expiring on the day preceding the day on which the Discriminatory Action was remedied.

Appendix III
Assessment of the PacifiCorp Renewable Wind Power Purchase Contract (PPA) and Related Risk Issues

The Major Allocations of Risk between Seller and Buyer in the EPA

1. Milestones, Milestone Extensions and Delays, Remedies for Milestone Failure .

PPA Sellers have duties to meet applicable Milestones and achieve completion of the Facility or face contract consequences for delays or failures in performance. See: Sections 2.2, 2.3, 10.1.2.4, 10.1.2.5 and 10.2 of the PPA.

Moreover, PPA Sellers face a "no notice and no opportunity to cure" risk of termination for any delay in obtaining the Commercial Operation Date (Section 10.1.2.5) and can get little meaningful relief from such risk from the Force Majeure provisions dealing with permits and required documentation. Under Section 2.3 of the PPA, Seller is required to pay defined Daily Delay Damages if the Commercial Operation Date occurs after the guaranteed date. The damages are to recover only cover damages between the reference market price for replacement power at a specified location and the contract price.

The delay damages collected from Sellers serve to offset the losses incurred by Buyers when replacement power must be purchased due to the late completion of the PPA projects. To the extent of such damages, ratepayers are in theory protected from the excess cost of replacement power over project costs.

2. Force Majeure Exclusion of Permit Risks Affecting Milestone Performance.

The Force Majeure definition explicitly excludes "(v) delay or failure of Buyer to obtain any Required Facility Document." Required Facility Document is defined include all Permits and agreements necessary for development, construction, operation and maintenance of the Facility. Accordingly, delay or failure of Seller to obtain its required permits is not an event of Force Majeure excusing a delay or failure of Seller to meet its Milestone duties. Such a

Milestone failure can then mature into a Seller Event of Default. PPA Sellers are entitled to no relief from Milestone failures due to permit delay[11].

3. General Force Majeure Standard.

The Force Majeure clause in the PPA identifies "an event that (a) is not reasonably anticipated as of the date hereof, and (b) is not within the reasonable control of the Party affected by the event". With this reliance on the concept of reasonableness, the clause is more flexible than others in the industry, but not uncommon in jurisdictions where PPAs are heavily negotiated by IPPs, sometimes assisted by regulators. The entire provision is reproduced with certain emphasis added as follows:

FORCE MAJEURE

> 14.1 Definition of Force Majeure. **"Force Majeure"** or "an event of Force Majeure" means **an event that (a) is not reasonably anticipated as of the date hereof, (b) is not within the reasonable control of the Party affected by the event**, (c) is not the result of such Party's negligence or failure to act, and (d) could not be overcome by the affected Party's use of due diligence in the circumstances. Force Majeure includes, but is not restricted to, events of the following types (but only to the extent that such an event, in consideration of the circumstances, satisfies the tests set forth in the preceding sentence): acts of God; fire; explosion; civil disturbance; sabotage; action or restraint by court order or public or government authority (as long as the affected Party has not applied for or assisted in the application for, and has opposed to the extent reasonable, such court or government action). Notwithstanding the foregoing, **none of the following constitute Force Majeure:** (i) Seller's ability to sell, or PacifiCorp's ability to purchase, energy or Green Tags at a more advantageous price than is provided hereunder; (ii) **the cost or**

[11] Curiously, PacifiCorp's standard form QF contract shows tolerance for permit delays similar to the tolerance unilaterally extended in the 2009 PacifiCorp RFP Contract Forms only to the Asset Purchase and Sale Agreement (APSA) resource. See: Section 13.1 of FORM OF POWER PURCHASE AGREEMENT [QUALIFYING FACILITIES IN EXCESS OF 1000 KILOWATT NET OUTPUT] (Force Majuere includes "other delay or failure in the performance as a result of any action or inaction on behalf of a public authority which is in each case (i) beyond the reasonable control of a party, (ii) by the exercise of reasonable foresight such party could not reasonably have been expected to avoid and (iii) by the exercise of due diligence, such party shall be unable to prevent or overcome.") For comparison purposes, see: MODEL DISPATCHABLE POWER PURCHASE AGREEMENT of Public Service Company of Colorado (distributed in connection with the Xcel 2005 All-Source RFP), in which in Section 14.1, Force Majeure is defined to include "actions by any Governmental Authority taken after the date hereof (including the adoption or change in any rule or regulation or environmental constraints lawfully imposed by such Governmental Authority) but only if such requirements, actions, or failures to act prevent or delay performance; and inability, despite due diligence, to obtain any licenses, permits, or approvals required by any Governmental Authority".

availability of fuel or motive force to operate the Facility; (iii) economic hardship, including lack of money; (iv) any breakdown or malfunction of Facility Wind Turbines or other equipment (including any serial equipment defect) that is not directly caused by an independent event of Force Majeure, (v) the imposition upon a Party of costs or taxes allocated to such Party under Section 5, (vi) **delay or failure of Seller to obtain or perform any Required Facility Document,** (vii) **any delay, alleged breach of contract, or failure by the Transmission Provider, Network Service Provider or Interconnection provider** (viii) maintenance upgrade or repair of any facilities or right of way corridors constituting part of or involving Interconnection Facilities, whether performed by or for Seller, or other third parties (except for repairs made necessary as a direct result of an event of Force Majeure); (ix) Seller's failure to obtain, or perform under, the Generation Interconnection Agreement, or its other contracts and obligations to Transmission Owner, Transmission Provider or Interconnection Provider; or (x) any event attributable to the use of Transmission Owner Interconnection Facilities for deliveries of Output to any party other than PacifiCorp. **Notwithstanding anything to the contrary herein, in no event will the increased cost of electricity, steel, labor, or transportation constitute an event of Force Majeure**.

<u>14.2 Suspension of Performance</u>. If either Party is rendered wholly or in part unable to perform its obligations hereunder because of an event of Force Majeure, both Parties shall be excused from the performance affected by the event of Force Majeure, provided that:

14.2.1 the Party affected by the Force Majeure, shall, within five (5) days after the occurrence of the event of Force Majeure, give the other Party written notice describing the particulars of the event; and

14.2.2 the suspension of performance shall be of no greater scope and of no longer duration than is required to remedy the effect of the Force Majeure; and

14.2.3 the affected Party shall use diligent efforts to remedy its inability to perform.

<u>14.3 Force Majeure Does Not Affect Other Obligations</u>. No obligations of either Party that arose before the Force Majeure causing the suspension of performance or that arise after the cessation of the Force Majeure shall be excused by the Force Majeure.

<u>14.4 Strikes</u>. Notwithstanding any other provision hereof, neither Party shall be required to settle any strike, walkout, lockout or other labor dispute on terms which, in the sole judgment of the Party involved in the dispute, are contrary to the Party's best interests.

> <u>14.5 Right to Terminate</u>**. If a Force Majeure event prevents a Party from substantially performing its obligations hereunder for a period exceeding 180 consecutive days** (despite the affected Party's effort to take all reasonable steps to remedy the effects of the Force Majeure with all reasonable dispatch), then the **Party not affected by the event of Force Majeure, with respect to its obligations hereunder, may terminate this Agreement by giving ten (10) days prior notice to the other Party.** Upon such termination, **neither Party will have any liability to the other** with respect to period following the effective date of such termination; provided, however, that this Agreement will remain in effect to the extent necessary to facilitate the settlement of all liabilities and obligations arising hereunder before the effective date of such termination.

As shown above, the Force Majeure clause specifically excludes, among others, the cost or availability of fuel or motive force to operate the Facility; economic hardship, including lack of money; any breakdown or malfunction of Facility Wind Turbines or other equipment (including any serial equipment defect) that is not directly caused by an independent event of Force Majeure.

4. <u>Force Majeure Exclusion of Required Facility Documents</u>.

As indicated above, delay or failure of Seller under the PPA in obtaining any Required Facility Document is not an event of Force Majeure. In Section 1.1, Required Facility Documents include all Permits financing related agreements, such as the lender consent and intercreditor and subordination agreements which the Company expects to execute. While PacifiCorp's actions as Buyer affect the ability of Seller to obtain such financing documents, Seller under the PPA remains at risk, without Force Majeure excuse, for any delay in satisfying its Milestones duties under Section 2.2. Such a Milestone failure can then mature into a Seller Event of Default under Section 10.1.2.4 and 10.1.2.5.

5. <u>Force Majeure and Change in Law Risks</u>.

In light of the well-understood fixed pricing provisions of the PPA, risk that costs to Buyers may increase to reflect certain Force Majeure and Change in Law events or occurrences does not exist for Buyers under the PPA. <u>Compare</u>: Sections 5.1.2 and 6.3.1.1 of the PPA.

6. <u>Capital Cost Escalation</u>.

Payments to PPA Sellers are not allowed to increase for any reason, including for reasons of Force Majeure or Change in Law. This applies equally before and after the Commercial Operation Date.

7. Energy Delivery Requirements, Availability Shortfalls and Replacement Power Costs.

During the portion of the PPA Term after the Commercial Operation Date, PPA Sellers are exposed to the risk of liquidated damages for failure to maintain their Guaranteed Availability. The shortfall is converted to a shortfall in MWH and liquidated damages are then due at the rate determined by the Buyer's Cost of Cover for the Contract Year in question. The formula multiplies the Expected Energy by the difference between the Guaranteed Availability and the defined Availability and then uses the Cost of Cover to obtain the liquidated damages. Availability is defined to include hours when the unavailability is due solely to Force Majeure; defaults by the Buyer and involuntary curtailments by the Transmission Provider and voluntary curtailments by the Buyer. It is important to note that the Seller is not penalized for events of Force Majeure, whether those events affect the performance of the Seller or the Buyer

8. Operational Performance Standards.

The operating standards are typical for the industry and include the general standards of a defined Prudent Electrical Practice, as well as the requirements of all applicable FERC, NERC and RTO rules.

9. Power Pricing and Price Escalation.

Under the present provisions of the specimen PPA, there is no evidence PPA Sellers are allowed to adjust pricing after the PPA is executed in order to compensate for greater than expected capital costs. It appears that pricing is restricted to bidding Energy Payment formulae that conform to fixed prices chosen by the bidders for future years and perhaps also fixed prices subject to inflation-based indices.

10. Fuel Infrastructure and Electric Interconnection Costs.

The costs of the electric interconnection for the Project is a part of the capital cost of the Project and electric interconnection cost increases that are experienced after the Effective Date of the PPA are the risk of the Seller. Payments to PPA Sellers are not allowed to increase for any reason, including, for any change in the scope of the electric interconnection. Under specific provisions of the PPA, the Sellers are made responsible for all costs associated with the interconnection of the Facility at the Point of Delivery as a Network Resource, including the costs of any System upgrades beyond the Point of Delivery.

11. <u>Lender Rights and Coordination</u>.

Security Interests are required to be given by PPA Sellers to Buyers in the Facility, the Premises and other real property interests, personal property and other assets needed to operate the Facility. The security interests are subordinate in right only to the interests of Senior Lenders. A pledge of ownership interests in the facility is given to the Buyer. A form of consent is attached which the Buyer agrees to execute with the Senior Lenders. .

Here, based on the present PPA form, PPA Sellers will experience added risk in negotiating additional lender provisions and may have to do so after PPA execution when time needed to meet construction financing milestone deadlines is expiring.

12. <u>Events of Default, Cure and Termination Rights</u>.

Subject to limited relief from the Force Majeure clause, PPA Sellers face an Event of Default if they fail to achieve the COD milestone by the Guaranteed COD, defined as 90 days after the Scheduled COD. The Event of Default matures immediately, without notice and an opportunity to cure. Of most importance, PPA Sellers, again with little, if any, effective Force Majeure relief, have no opportunity to avoid an Event of Default and to cure a failure to achieve the Commercial Operation Date by the Guaranteed Commercial Operation Date even if the Facility is then within days of completion. After the COD, another Seller Event of Default is the failure, after applicable notice and cure periods, to maintain all Required Facility Documents and all Permits, land rights, interconnection rights and other material rights needed to own or operate the Facility

The blanket default clause provides for both parties a 30-day cure period, extendable for an additional 60 days if the default is capable of being cured in the 60-day period and the affected party initiates cure within the first 30 day period. Events of Default entitle the non-defaulting party to terminate and to pursue all available remedies at law or in equity. Termination damages are due, but in no case is the non-defaulting party obligated to pay the Gains it may experience as a result of the failure.

Failures to sell and deliver Net Output or to purchase and pay for Net Output are treated comparably in terms of entitling the non-defaulting party to the Cost of Cover. For Sellers, when the Buyer has failed to take the Net Output, and the Seller cannot sell to third parties, the Buyer must pay to the Seller PTC Amount designed to make the Seller whole for the loss of tax benefits.

If the Seller fails to achieve the COD, the Buyer has the right to step-in, complete construction at the cost of the Seller and to operate for the Seller's account. The Buyer has options to return the Facility to the Seller or if the Seller will not execute a necessary release for the Buyer's operation of the Facility, to terminate the PPA without damages. When a Seller Event of Default results in termination, the Buyer has rights to Delay Damages and termination damages, as well as a Covered Facility Right of First Offer on any facility constructed by the Seller or an Affiliate on the Premises. The Buyer enjoys a right of first offer whenever the Seller wants to sell the Facility, expand the Facility or transfer controlling interests in the Seller or in the Facility.

13. <u>Consequential Damages</u>.

The ban on consequential damages is a bilateral ban on consequential damages. See: Section 11.3 of the PPA.

14. <u>Disposition of the Seller's Plant upon Expiration of the Term</u>.

The PPA contains a specimen provision for the exercise by the Buyer of an option to purchase the plant at the expiration. The provision is apparently optional under the terms of the applicable RFP.

Appendix IV
Assessment of the PG&E 2009 Renewables Power Purchase Agreement (PPA)

Price and Delivery Requirements and Related Risk Issues

Article Three of the PG&E 2009 Renewables PPA is attached hereto. Guaranteed Energy Production (GEP) is a requirement for wind and non-wind "As Available" Products. For non-wind renewable resources, the GEP is based on the Contract Quantity which is a scheduled amount of energy bid by the IPP. The GEP requirement is applied for each two consecutive Contract Years and calls for the delivery of 160% of the Contract Quantity for such two-year period. The specific terms are as follows:

> "Guaranteed Energy Production" means an amount of Delivered Energy, as measured in MWh, equal to the product of (x) and (y), where (x) is one hundred sixty percent (160%) of the Contract Quantity ***[Photovoltaic facilities onl***y ***to use the then-applicable Contact Quantities for the Performance Measurement Period]***, and (y) is the difference between (I) and (II), with the resulting difference divided by (I), where (I) is the number of hours in the applicable Performance Measurement Period and (II) is the aggregate number of Seller Excuse Hours in the applicable Performance Measurement Period. Guaranteed Energy Production is described by the following formula:
>
> Guaranteed Energy Production = (160% * Contract Quantity in MWh) * [(Hours in Performance Measurement Period – Seller Excuse Hours) / Hours in Performance Measurement Period]

Note that Seller Excuse Hours are credited against the requirement.

For wind facilities, the GEP is evaluated each Contract Year against the P-95 Value for the facility. The P-95 Value is defined as follows:

I. *"P-95 Value" means the amount of Energy that is expected to be generated ninety five percent (95%) of the time on an annual basis and inclusive of potential outages and reported in the Final Output Report. [For wind facilities only]*

The GEP requirement is set forth as follows:

> "Guaranteed Energy Production" means an amount of Delivered Energy, as measured in MWh, equal to the product of (x) and (y), where (x) is the applicable P-95 Value in the Final Output Report, and (y) is the difference between (I) and (II), with the resulting difference divided by (I), where (I) is the number of hours in the applicable Performance Measurement Period and (II) is the aggregate number of Seller Excuse Hours in the applicable Performance Measurement Period. Guaranteed Energy Production is described by the following formula:

Guaranteed Energy Production = (P-95 Value for Performance Measurement Period) * [(Hours in Performance Measurement Period – Seller Excuse Hours) / Hours in Performance Measurement Period]

If there is a shortfall or GEP Failure, the GEP Cure is defined as the delivery in the next following Contract Year of 90% of the Contract Quantity. In the absence of the GEP Cure, GEP Damages are due, based on the cost of cover, which has a minimum value of $20/MWh. The Appendix VII GEP Damages Calculation is set forth below. In addition, the Force Majeure definition has been reproduced below as a final attachment hereto.

PG&E 2009 Renewables PPA Price and Guarantee Provisions

A. ARTICLE THREE: OBLIGATIONS AND DELIVERIES

3.1 Seller's and Buyer's Obligations.

(a) Product. The Product to be delivered and sold by Seller and received and purchased by Buyer under this Agreement is an **[**As-Available**]** **[**Baseload**]** **[**Peaking**]** **[**Dispatchable**]** Product. ***[Seller to select applicable Product]***

(b) Transaction. Unless specifically excused by the terms of this Agreement during the Delivery Term, Seller shall sell and deliver, or cause to be delivered, and Buyer shall purchase and receive, or cause to be received, the Product at the Delivery Point, and Buyer shall pay Seller the Contract Price in accordance with the terms of this Agreement. In no event shall Seller have the right (i) to procure any element of the Product from sources other than the Project for sale or delivery to Buyer under this Agreement [except with respect to Energy delivered to Buyer in connection with Energy Deviations] ***[Short Term Offers Outside California: Seller to delete]*** or (ii) sell Product from the Project to a third Party [other than in connection with Energy Deviations] ***[Short Term Offers Outside California: Seller to delete]***. Buyer shall have no obligation to receive or purchase Product from Seller prior to or after the Delivery Term[, except during the Test Period] ***[Short Term Offers Outside California: Seller to delete or revise, if Delivery Point is not to CAISO Grid].*** Seller shall be responsible for any costs or charges imposed on or associated with the Product or its delivery of the Product up to the Delivery Point. Buyer shall be responsible for any costs or charges imposed on or associated with the Product after its receipt at and from the Delivery Point. Each Party agrees to act in good faith in the performance of its obligations under this Agreement. ***[Short Term Offers: See also Attachment N for alternatives]***

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

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

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

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

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

[Short Term Offers: Seller to indicate non-standard Delivery Term and insert number of Contract Years or fraction thereof above and to revise bracketed text to correspond]] As used herein, "Delivery Term" shall mean the period of [__ months of a ______] Contract Year[s] specified above beginning on the first date that Seller delivers Product to Buyer from the Project ("Initial Energy Delivery Date") in connection with this Agreement and continuing until the end of the ***[insert term to correspond to term checked and described above]*** Contract Year unless terminated as provided by the terms of this Agreement. The Initial Energy Delivery Date shall occur as soon as practicable once all of the following have been satisfied: (A) the Commercial Operation Date has occurred; (B) Buyer shall have received and accepted the Delivery Term Security in accordance with the relevant provisions of Article Eight of the Agreement, as applicable; (C) Seller shall have obtained the requisite CEC Certification and Verification for the Project; **[**and**]** (D) all of the applicable Conditions Precedent in Section 2.4(a) of the Agreement have been satisfied or waived in writing **[**, and (E) Buyer shall have received written notice from the CAISO that the Project is certified as a Participating Intermittent Resource to the extent such status is available at such time as the conditions in subsections (A) through (D) of this Section 3.1(c) are satisfied. If subsection (E) is applicable, Seller shall obtain such certification no later than one hundred twenty (120) days following the Commercial Operation Date.**]** As evidence of the Initial Energy Delivery Date, the Parties shall execute and exchange the "Initial Energy Delivery Date Confirmation Letter" attached hereto as Appendix II on the Initial Energy Delivery Date. ***[Subsection (E) applicable to California wind Projects only]***

(d) Delivery Point. The Delivery Point shall be [the PNode designated by the CAISO for the Project]. ***[Short Term Offers Outside California: Seller to revise bracketed text]***

(e) Contract Quantity **[**and Guaranteed Energy Production**]**. ***[Peaking and Dispatchable Offers should delete the bracketed language in this heading]***

(i) Contract Quantity. The Contract Quantity during each Contract Year is the amount set forth in the applicable Contract Year in the "Delivery Term Contract Quantity Schedule," attached hereto as Appendix V**,** which amount is inclusive of outages**.** ***[Seller shall provide the Contract Quantity amount listed in its Offer on the worksheet in the Bid Offer Forms applicable to the Product. For a Baseload Product, the minimum qualifying Contract Quantity is equivalent to an 80 percent Capacity Factor. For a Peaking Product, the minimum qualifying Contract Quantity is equivalent to a 95 percent Capacity Factor.]***

[Use the following bracketed language for As-Available Product delivered by all facilities other than wind]

[(ii) Guaranteed Energy Production.

(A) Throughout the Delivery Term, Seller shall be required to deliver to Buyer no less than the Guaranteed Energy Production over [two (2) consecutive Contract Years] during the Delivery Term ("Performance Measurement Period"). ***[Short Term Offers: Performance Measurement Period to be revised based on Delivery Term]*** "Guaranteed Energy Production" means an amount of Delivered Energy, as measured in MWh, equal to the product of (x) and (y), where (x) is one hundred sixty percent (160%) of the Contract Quantity ***[Photovoltaic facilities only to use the then-applicable Contact Quantities for the Performance Measurement Period]***, and (y) is the difference between (I) and (II), with the resulting difference divided by (I), where (I) is the number of hours in the applicable Performance Measurement Period and (II) is the aggregate number of Seller Excuse Hours in the applicable Performance Measurement Period. Guaranteed Energy Production is described by the following formula:

Guaranteed Energy Production = (160% * Contract Quantity in MWh) * [(Hrs in Performance Measurement Period – Seller Excuse Hrs) / Hrs in Performance Measurement Period]

[Use the following bracketed language for wind facility]

[(ii) Guaranteed Energy Production.

(A) Throughout the Delivery Term, Seller shall be required to deliver to Buyer no less than the Guaranteed Energy Production each Contract Year during the Delivery Term

(“Performance Measurement Period”). “Guaranteed Energy Production” means an amount of Delivered Energy, as measured in MWh, equal to the product of (x) and (y), where (x) is the applicable P-95 Value in the Final Output Report, and (y) is the difference between (I) and (II), with the resulting difference divided by (I), where (I) is the number of hours in the applicable Performance Measurement Period and (II) is the aggregate number of Seller Excuse Hours in the applicable Performance Measurement Period. Guaranteed Energy Production is described by the following formula:

Guaranteed Energy Production = (P-95 Value for Performance Measurement Period) * [(Hrs in Performance Measurement Period – Seller Excuse Hrs) / Hrs in Performance Measurement Period]

[Use the following bracketed language for Baseload Product only]

[(ii) Guaranteed Energy Production.

(A) Throughout the Delivery Term, Seller shall be required to deliver to Buyer no less than the Guaranteed Energy Production in each Contract Year during the Delivery Term (“Performance Measurement Period”). “Guaranteed Energy Production” means an amount of Delivered Energy, as measured in MWh, equal to the product of (x) and (y), where (x) is ninety percent (90%) of the Contract Quantity, and (y) is the difference between (I) and (II), with the resulting difference divided by (I), where (I) is the number of hours in the applicable Performance Measurement Period and (II) is the aggregate number of Seller Excuse Hours in the applicable Performance Measurement Period. Guaranteed Energy Production is described by the following formula:

Guaranteed Energy Production = (90% * Contract Quantity in MWh) * [(Hrs in Performance Measurement Period – Seller Excuse Hrs) / Hrs in Performance Measurement Period]

[Use the following subpart (B) to Section 3.1(e)(ii) for both As-Available and Baseload Products and all technologies]

(B) (I) If Seller has a GEP Failure, then within forty-five (45) days after the last day of the last month of such Performance Measurement Period, Buyer shall promptly notify Seller of such failure. Seller may cure the GEP Failure by delivering to Buyer no less than ninety percent (90%) of the Contract Quantity over the next following Contract Year (“GEP Cure”). If Seller fails to generate sufficient Delivered Energy to make the GEP Cure for a given Performance Measurement Period, Seller shall pay GEP Damages, calculated pursuant to Appendix VII (GEP Damages Calculation).

(II) The Parties agree that the damages sustained by Buyer associated with Seller’s failure to achieve the Guaranteed Energy Production requirement would be difficult or impossible to determine, or that obtaining an adequate remedy would be unreasonably time consuming or expensive and therefore agree that Seller shall pay the GEP Damages to Buyer as liquidated damages. In no event shall Buyer be obligated to pay GEP Damages.

(III) After the GEP Cure period has run, if Seller has not achieved the GEP Cure, Buyer shall have forty-five (45) days to notify Seller of such failure. Within forty-five (45) days of the end of the GEP Cure period, Buyer shall provide Notice to Seller in writing of the amount of the GEP Damages, if any, which Seller shall pay within sixty (60) days of receipt of the Notice. If Seller does not pay the GEP Damages within the sixty (60) day time period, Buyer may, at its option, declare an Event of Default pursuant to Section 5.1(b)(vi)(A). If Buyer does not (1) notify Seller of the GEP Failure or (2) declare an Event of Default pursuant to Section 5.1(b)(vi), if Seller has failed to pay the GEP Damages, then Buyer shall be deemed to have waived its right to declare an Event of Default based on Seller's failure with respect to the Performance Measurement Period which served as the basis for the notice of GEP Failure, GEP Damages, or default, subject to the limitations set forth in Section 5.1(b)(vi)(B).

[Use the following version of Section 3.1(f) Contract Capacity for As-Available Product only]

[(f) Contract Capacity. The generation capability designated for the Project shall be **[____]** MW net of all auxiliary loads, station electrical uses, and Electrical Losses (the "Contract Capacity"). Throughout the Delivery Term, Seller shall sell and Schedule all Product produced by the Project solely to Buyer and in no event shall Buyer be obligated to receive or pay for, in any hour, any Delivered Energy that exceeds the Contract Capacity**.]**

[Use the following version of Section 3.1(f) Contract Capacity/Declared Contract Capacity/Net Rated Output Capacity for Baseload, Peaking or Dispatchable Product only]

[(f) Contract Capacity/Declared Contract Capacity/Net Rated Output Capacity.

(i) Contract Capacity; Declared Contract Capacity. The capacity of the Project at any time shall be the lower of the following: (A) **[____]** MW of Declared Contract Capacity or (B) the Net Rated Output Capacity of the Project (the "Contract Capacity"). Throughout the Delivery Term, Seller shall sell and Schedule all Product produced by the Project solely to Buyer and in no event shall Buyer be obligated to receive or pay for, in any hour, any Product, as measured by Delivered Energy that exceeds the Contract Capacity.

(ii) Net Rated Output Capacity Testing. Buyer shall have the right to request a Capacity Test as set forth in Appendix VI, to determine the Net Rated Output Capacity. The resulting Net Rated Output Capacity shall remain in effect until the next Capacity Test requested by Buyer. Appendix VI sets forth the agreements of Buyer and Seller with respect to the performance of Capacity Tests.**]**

[Use the following version of Section 3.1(g) Project for As-Available Product only]

[(g) Project.

(i) All Product provided by Seller pursuant to this Agreement shall be supplied from the Project only. Seller shall not make any alteration or modification to the Project which results in a change to the Contract Capacity or the anticipated output of the Project without Buyer's prior written consent. The Project is further described in Appendix IV.

(ii) Seller shall not relinquish its possession or demonstrable exclusive right to control the Project without the prior written consent of Buyer, except under circumstances provided in Section 10.6(b). Seller shall be deemed to have relinquished possession of the Project if after the Commercial Operation Date Seller has ceased work on the Project or ceased production and delivery of Product for a consecutive thirty (30) day period and such cessation is not a result of a Force Majeure event or direct action of Buyer.**]**

[Use the following version of Section 3.1(g) Project for Baseload, Peaking or Dispatchable Product only]

[(g) Project.

(i) All Product provided by Seller pursuant to this Agreement shall be supplied from the Project only. Seller shall not make any alteration or modification to the Project which results in a change to the Net Rated Output Capacity or the anticipated output of the Project without Buyer's prior written consent. The Project is further described in Appendix IV.

(ii) Seller shall not relinquish its possession or demonstrable exclusive right to control the Project without the prior written consent of Buyer, except under circumstances provided in Section 10.6(b). Seller shall be deemed to have relinquished possession of the Project if after the Commercial Operation Date Seller has ceased work on the Project or ceased production and delivery of Product for a consecutive thirty (30) day period and such cessation is not a result of a Force Majeure event or direct action of Buyer.**]**

PG&E Appendix VII
GEP DAMAGES CALCULATION

In accordance with the provisions in Section 3.1(e)(ii), GEP Damages means the liquidated damages payment due by Seller to Buyer, calculated as follows:

[(A – B) X (C – D)]

Where:

A = the Guaranteed Energy Production for the Performance Measurement Period, in MWh

B = Sum of Delivered Energy over the Performance Measurement Period, in MWh

C= Replacement Price for the Performance Measurement Period, in $/MWh, reflecting the sum of (a) the simple average of the simple average of the Day Ahead Integrated Forward Market hourly price, as published by the CAISO, for the Existing Zone Generation Trading Hub, in which the PNode resides, plus (b) $50/MWh

D = the unweighted Contract Price specified in Section 4.1 for the Performance Measurement Period, in $/MWh

The Parties agree that in the above calculation of GEP Damages, the result of "(C-D)" shall not be less than $20/MWh.

II. *PG&E Force Majeure Definition (emphasis added.)*

III.

IV. *"Force Majeure" means any event or circumstance which wholly or partly prevents or delays the performance of any material obligation arising under this Agreement, but only if and to the extent (i)* ***such event is not within the reasonable control, directly or indirectly, of the Party seeking to have its performance obligation(s) excused thereby****, (ii) the Party seeking to have its performance obligation(s) excused thereby has taken all reasonable precautions and measures in order to prevent or avoid such event or mitigate the effect of such event on such Party's ability to perform its obligations under this Agreement and which by the exercise of due diligence such Party could not reasonably have been expected to avoid and which by the exercise of due diligence it has been unable to overcome, and (iii) such event is not the direct or indirect result of the negligence or the failure of, or caused by, the Party seeking to have its performance obligations excused thereby.*

(a) Subject to the foregoing, events that could qualify as Force Majeure include, but are not limited to, the following:

(i) flooding, lightning, landslide, earthquake, fire, drought, explosion, epidemic, quarantine, storm, hurricane, tornado, other natural disaster or unusual or extreme adverse weather-related events;

(ii) war (declared or undeclared), riot or similar civil disturbance, acts of the public enemy (including acts of terrorism), sabotage, blockade, insurrection, revolution, expropriation or confiscation;

(iii) except as set forth in subsection (b)(vii) below, strikes, work stoppage or other labor disputes (in which case the affected Party shall have no obligation to settle the strike or labor dispute on terms it deems unreasonable); or

(iv) emergencies declared by the Transmission Provider or any other authorized successor or regional transmission organization or any state or federal regulator or legislature requiring a forced curtailment of the Project or making it impossible for the Transmission Provider to transmit Energy, including Energy to be delivered pursuant to this Agreement; provided that, if a curtailment of the Project pursuant to this subsection (a)(iv) would also meet the definition of a Curtailment Period, then it shall be treated as a Curtailment Period for purposes of Section 3.1(i).

(b) Force Majeure shall not be based on:

(i) **Buyer's inability economically to use or resell the Product purchased hereunder;**

(ii) Seller's ability to sell the Product at a price greater than the price set forth in this Agreement;

(iii) **Seller's inability to obtain permits or approvals of any type for the construction, operation, or maintenance of the Project;**

(iv) **Seller's inability to obtain sufficient fuel, power or materials to operate the Project,** except if Seller's inability to obtain sufficient fuel, power or materials is caused solely by an event of Force Majeure of the specific type described in any of subsections (a)(i) through (a)(iv) above;

(v) Seller's failure to obtain additional funds, including funds authorized by a state or the federal government or agencies thereof, to supplement the payments made by Buyer pursuant to this Agreement;

(vi) a Forced Outage except where such Forced Outage is caused by an event of Force Majeure of the specific type described in any of subsections (a)(i) through (a)(iv) above;

(vii) a strike, work stoppage or labor dispute limited only to any one or more of Seller, Seller's Affiliates, [the EPC Contractor or subcontractors thereof] ***[Short Term Offers from Short Term Existing: Seller to delete bracketed language]*** or any other third party employed by Seller to work on the Project;

(viii) any equipment failure except if such equipment failure is caused solely by an event of Force Majeure of the specific type described in any of subsections (a)(i) though (a)(iv) above; or

(ix) a Party's inability to pay amounts due to the other Party under this Agreement, except if such inability is caused solely by a Force Majeure event that disables physical or electronic facilities necessary to transfer funds to the payee Party.

Appendix V
Assessment of the Hawaiian Electric Company 2008 Renewables Power Purchase Agreement (PPA)

Price and Delivery Requirements and Related Risk Issues

Section 2 of the Hawaiian Electric Company (HECO) 2008 Renewables PPA is attached hereto. The pricing provisions in Section 2(b) allow the delivery of up to 120% of the Annual Contract Energy which will be priced at the contract price. However, if that amount is exceeded, the price of the amount in excess of the Annual Contract Energy is reduced to 75% of the contract price.

In addition, there is an adjustment mechanism which annually in each year after the fourth Contract Year compares the rolling three-year average of the Annual Adjusted Energy (Average Annual Energy) to the Annual Contract Energy. If the Average Annual Energy is less than 80% of the Annual Contract Energy, then the Annual Contract Energy must be reduced to the lowest three-year rolling average of the Average Annual Energy.

2) Purchase and Sale of Energy; Rate for Purchase and Sale; Billing and Payment

(a) The Seller agrees to deliver to the Company all of the Actual Output produced by the Facility and delivered to the Point of Interconnection from the initial delivery of energy under this Contract through the end of the Term, and for such additional period as provided in Section 12(a) (Term), in accordance with the terms and conditions of this Contract. The Company agrees to purchase energy from the Seller pursuant to the terms and conditions which are more fully described below in (b) and in Appendix D, Energy Purchases By the Company. Included in the purchase and sale of Actual Output are all of the Environmental Credits associated with the Actual Output. The Company will not reimburse the Seller for any taxes or fees imposed on the Seller including, but not limited to, State of Hawaii general excise tax.

(b) The Seller will be paid for Actual Output on a monthly basis equal to the product of the price specified in Appendix D and the Actual Output; provided, in any Contract Year, if the Actual Output exceeds 120% of the quantity of Annual Contract Energy specified in subsection (e), below, the price paid on a monthly basis for the Actual Output in excess of the Annual Contract Energy in such Contract Year shall be 75% of the Contract Price for such month. The level of Annual Contract Energy shall be adjusted based on the performance of the Seller in meeting its Contract requirements. For the first four Contract Years of the Contract, the Annual Contract Energy will be the Annual Contract Energy specified in Section 2(e). After the fourth Contract Year and subsequently on each anniversary of the end of the fourth Contract Year, the Company will calculate the Average Annual Energy. When the Average Annual Energy is less than 80% of the Annual Contract Energy for that same three-year period, the Annual Contract Energy amount will be reduced such that the Annual Contract Energy in any year shall be based on the lowest three year rolling average of Average Annual Energy. For the period following the Effective Date and prior to the earlier of the Initial In-Service Date, the Non-Appealable PUC Approval Order Date or the Waiver Agreement Date, the Company shall not be obligated to accept or pay for any energy delivered by the Seller, however, any energy accepted by the Company during this period shall be paid for at a rate equivalent to 75% of the first year Contract Price. For the period following the earlier of the Initial In-Service Date, the Non-Appealable PUC Approval Order Date or the Waiver Agreement Date and prior to the Commercial Operation Date, Company shall be obligated to accept and pay for energy, except for those circumstances set forth in Section 8(a) of this Contract, from each new generating unit as it is installed and successfully completes the Control System Acceptance Test(s), up to the Allowed Capacity, however, energy accepted by the Company during this period shall be paid for at a rate equivalent to 75% of the first year Contract Price.

(c) Curtailment adjustments will be based on the difference between the Actual Output during any hour of curtailment and the Uncurtailed Output. This difference is the Curtailed Excess Energy. For purposes of calculating Uncurtailed Output, the Seller shall provide an estimate to the Company with data reasonably sufficient to calculate the Facility’s Ideal Output during the hour of curtailment.

(d) The initial Annual Contract Energy is set at ___ MWh for a Contract Year.

(e) The Contract Capacity is set at ___ MW and is equal to the Allowed Capacity as specified in Appendix A. Seller shall not make any alteration or modification to the Facility which results in a change to the Contract Capacity without the Company’s prior written consent.

(f) Sales of energy by the Company to the Seller shall be governed by an applicable rate schedule filed with the PUC and not by this Contract, except with respect to the reactive amount adjustment referred to in Appendix B.

(g) By the fifth Business Day of each calendar month, the Company shall provide the Seller or its designated agent with the appropriate data for the Seller to compute the energy charge for the Actual Output in the preceding calendar month as determined in accordance with this Contract.

(h) By the tenth Business Day of each calendar month, the Seller shall submit to the Company an invoice that separately states the following for the preceding month: (1) the Actual Output during this period; (2) the energy charge for energy purchased by the Company as set forth in Appendix D of this Contract; and (3) the monthly metering charge as set forth in Section 7 of this Contract.

(i) By the twentieth Business Day of each calendar month (but, except as otherwise provided in the following sentence, no later than the last Business Day of that month if there are less than twenty Business Days in that month), the Company shall make payment on such invoice, or provide to the Seller an itemized statement of its objections to all or any portion of such invoice and pay any undisputed amount. The time in which the Company must make payment to Seller shall be increased on a day-for-day basis for each Day that Seller is delinquent in providing to the Company the information under Section 2(c) of this Contract. If the Company is not timely in providing data required in Section 2(c) and the Seller’s invoice is subsequently not received by the Company in accordance with Section 2(a), the Company must still meet the twentieth Business Day payment date. An estimated payment, subject to reconciliation with the complete invoice, may be made as an interim provision until a complete invoice can be prepared by the Seller and received by the Company.

(j) Notwithstanding all or any portion of such invoice in dispute, any payment not made to the Seller by the twentieth Business Day of each calendar month (or the last Business Day of that month if there are less than twenty Business Days in that month), or by the due date for such payment if extended pursuant to subsection (e), above, shall accrue interest at the average daily prime rate at the Bank of Hawaii plus two percent (2%) for the period until the outstanding interest and invoiced amounts (or amounts due to the Seller if determined to be less than the invoiced amounts) are paid in full. Partial payments shall be applied first to outstanding interest and then to outstanding invoice amounts.

(k) In the event adjustments are required to correct inaccuracies in an invoice after payment, the party requesting adjustment shall recompute and include in the party’s request the amounts due during the period of the inaccuracy. The difference between the amount paid and that recomputed for the invoice shall either be (i) paid to Seller, or set-off by the Company against the next invoice payment to Seller, as appropriate, together with interest from the date that such invoice was payable until the date that such recomputed amount is paid at the average daily prime rate at the Bank of Hawaii for the period, or (ii) objected to by the party responsible for such payment within thirty (30) Days following its receipt of such request. All claims for adjustments shall be waived for any deliveries of electricity made more than thirty-six (36) months preceding the date of any such request.

The Seller, after giving reasonable advance written notice to the Company, shall have the right to review all billing, metering and related records relating to the Seller's Facility during normal working hours on Business Days. The Company shall maintain such records for a period of not less than thirty-six (36) months.

APPENDIX VI

Summary of Pricing, Delivery and Performance Requirements from Various US Renewable Power Purchase Agreements (2002 to 2008)

1. [NAME WITHHELD FOR PROPRIETARY REASONS] AND FIRST ENERGY

(b) **Failure to Deliver**: At the conclusion of the first three years of operation, except to the extent generation is prevented by Force Majeure, Delivery Excuse or any other default or reason caused by Buyer, the Plant must generate the Guaranteed Energy Output [xxxxx MWh] per year average, as well as for each succeeding year, on a three-year rolling average. Except as generation may be prevented as described, in the event any three-year rolling average is less than the Guaranteed Energy Output , [Name Withheld]. will credit FirstEnergy Solutions the difference between the actual average and the Guaranteed Energy Output at $5.00 per MWh, provided, however, in no event shall such annual credit exceed the amount of $xxxxxxx, notwithstanding the value of such actual difference. Buyer and Seller agree that payments or credits made to or received by Buyer under this Section 4.1(b) shall be liquidated damages, and not a penalty and shall be Buyer's exclusive remedy for any failure in the performance of Seller in supplying Products provided for under this Agreement, except as specifically provided under Sections 5.1(g), (k), (s) or (u). Comment: a "cap" on this annual exposure may be needed for financing reasons.

Appendix VI

2. **FIRST ENERGY SOLUTIONS AND [NAME WITHHELD]**

"Delivery Excuse" means at any time, before or after the Commercial Operation Date, during the Term any of the following: (i) any Event of Default of Buyer; (ii) any delay or failure by Buyer in giving any approval, or deciding whether to give any approval, within the times required under this Agreement; (iii) any delay or failure by Buyer in performing any obligation under this Agreement; and (iv) any failure of Buyer to have adequate transmission rights to take delivery from Seller at the Point of Delivery.

V. Article 4 - Commercial Operation

4.1 Construction Milestones and Commercial Operation. Except to the extent failure may be caused by an event or condition of Force Majeure, Delivery Excuse or delay in the execution or performance of the Interconnection Service Agreement not caused by Seller, Seller agrees to meet the Construction Milestones set forth in Exhibit A to this REPA., including, without limitation, the Commercial Operation Milestone. Delays excused as set forth above shall cause extension of all affected Construction Milestones to the extent required. Subject to the foregoing, the Facility shall be fully capable of reliably producing the Renewable Energy to be provided under this REPA and delivering such Renewable Energy to Buyer at the Point of Delivery, no later than the Commercial Operation Milestone.

. . . . .

7.1 Sale and Purchase. Beginning on the Commercial Operation Date, Seller shall generate from the Facility, deliver to the Point of Delivery, and sell to Buyer at the applicable prices set forth in Article 8, and Buyer shall accept at the Point of Delivery, and purchase and pay Seller for at the applicable prices set forth in Article 8, all Renewable Energy generated by the Facility and, if any, the Ancillary Services, Capacity Credits, and Unforced Capacity (the "Related Products") and the Environmental Credits as, when and to the extent ascribed to the Facility in connection with the generation of Renewable Energy. As provided in Section 5.1 of this Agreement, Seller shall make available to Buyer for purchase and Buyer shall purchase all Renewable Energy the Facility is capable of generating at any time without regard to the scheduling thereof, which scheduling shall be the responsibility and obligation of Buyer hereunder. Notwithstanding the foregoing, Buyer and Seller agree that the Facility may not now or at any time hereafter qualify to produce any of the Related Products and that the applicable prices shall not change due to the Facility's ability or inability to qualify to produce the Related Products or due to any changes in the definitions of such products during the Term. Without limiting the foregoing, Seller is under no obligation to provide the Related Products or Environmental Credits to Buyer to the extent that qualification to produce and deliver such products requires anything other than the measurement of the Renewable Energy delivered by the Facility and tracking and registration in accordance with the Generation Attributes Tracking System ("GATS") of PJM, or, should GATS tracking not be applicable for any reason, tracking and registration in accordance with industry standard attestation and tracking. In no event will Seller be required to incur any material increase in its capital or operating costs in order to qualify to provide such products.

7.2 Committed Renewable Energy. Seller hereby commits to deliver to Buyer at the Point of Delivery all of the Renewable Energy produced by the Facility except for station power, inadvertent flows and energy sold to others under the circumstances authorized by Buyer or otherwise permitted under this REPA.

7.3 Title and Risk of Loss. As between the Parties, Seller shall be deemed to be in control of the Renewable Energy and Test Energy output from the Facility up to and until delivery and receipt at the Point of Delivery and Buyer shall be deemed to be in control of such energy from and after delivery and receipt at the Point of Delivery. Title and risk of loss related to the Renewable Energy and Test Energy shall transfer from Seller to Buyer at the Point of Delivery.

8.1 Price. Commencing on the Commercial Operation Date, Buyer shall pay Seller for Renewable Energy delivered to Buyer by Seller to the Point of Delivery in a Commercial Operation Year during each Commercial Operation Year at an energy payment rate equal to $XXX per MWh (such amount is referred to herein as the "Renewable Energy Payment Rate"). The Renewable Energy Payment Rate shall be fixed for the Term and shall not be subject to increase or escalation for any reason.

8.2 Payment for Curtailment Energy. If delivery of Renewable Energy is curtailed for any reason other than an Excused Curtailment as defined in Section 8.4, the Parties shall use reasonable efforts to determine the quantity of Renewable Energy that would have been produced by the Facility and delivered to the Point of Delivery had its generation not been so curtailed ("Curtailment Energy") and Buyer shall compensate Seller for such Curtailment Energy as provided in this Section 8.2. For the avoidance of doubt, any delivery curtailed due to a failure of Buyer to obtain firm transmission from the Point of Delivery shall result in Curtailment Energy. For all Curtailment Energy during each Contract Year, Buyer shall compensate Seller for (1) all amounts that Seller would have received from Buyer under this REPA had production not been so curtailed and (2) the amount of any PTCs to which Seller would have been entitled had production not been so curtailed, but which Seller does not receive, on a grossed up basis.

8.3 Wind Measuring Equipment. Seller shall install sufficient meteorological towers around the Site or in conjunction with the Wind Turbines to provide the capability of measuring and recording representative wind data 24 hours per day. Buyer shall have the right on a real time basis to access this data electronically at Buyer's expense.

8.4 Excused Curtailment. Notwithstanding anything in this Article 8 to the contrary, and for avoidance of doubt, no payment shall be due Seller under Section 8.1 or Section 8.2 for curtailments of delivery of Renewable Energy which Seller is otherwise capable of delivering, resulting from any of the following ("Excused Curtailment"): (i) action by the Interconnected Transmission Owner due to a failure of Seller to perform its obligations under the Interconnection Service Agreement; or (ii) an Emergency Condition.

Appendix VI

3. PUBLIC SERVICE OF COLORADO AND [NAME WITHHELD] (2002)

"Annual Maximum Contract Energy" shall mean xxx GWh per Commercial Operation Year, or such lesser amount as adjusted on a pro rata basis if an Alternative Facility Configuration is used with less than xxx MW of nameplate capacity.

"Replacement Power Costs" means the costs incurred by PSCo for the capacity and energy which is necessary to replace that which Seller, in accordance with this WESA, would have delivered to PSCo from the Facility but failed to provide due to a Default by Seller, less the sum of any payments from PSCo to Seller, under this WESA, which were eliminated as a result of such failure. These costs include, but are not limited to, the amounts paid by PSCo for replacement capacity and energy, transmission of replacement capacity and energy, and transaction costs. The capacity and energy shall be the MWh of Expected Mean Production for the applicable month and hour set forth in Table 1 of Exhibit G, as the same may be adjusted as set forth in Exhibit G.

B. Article 4—Commercial Operation

VI. 4.1 Commercial Operation. The Facility shall achieve Commercial Operation no later than the Commercial Operation Milestone Date.

VII. 4.2 Construction Milestones. In order to achieve the Commercial Operation Date of the Facility by the Commercial Operation Milestone Date, Seller agrees to meet the Construction Milestones set forth in Exhibit A to this WESA.

VIII. 6.1 Sale and Purchase.

(A) Beginning on the Commercial Operation Date of the Facility, Seller shall supply from the Facility and sell to PSCo, and PSCo shall receive and purchase from Seller, all Contract Energy delivered to the Point of Delivery. Seller shall deliver such Contract Energy to PSCo at the Point of Delivery set forth in Exhibit C to this WESA. To the extent the Facility is available to operate, all of the Contract Energy shall be made available for delivery to the Point of Delivery for purchase by PSCo under this WESA and PSCo shall receive and purchase all of the Contract Energy. Except as provided in this Section 6.1, PSCo shall only pay for Contract Energy actually delivered and metered at the Point of Delivery and PSCo shall not be obligated to pay any amounts for energy not delivered by Seller and received by PSCo for any other reason.

(B) The Parties acknowledge that PSCo's Transmission System may experience constraints from time to time which may affect Seller's ability to deliver Contract Energy. In some cases, the transmission constraint affecting delivery of Contract Energy can be reduced or eliminated by reducing electric generation at other generation facilities in the region; in other cases, the transmission constraint cannot be reduced or eliminated by reducing the electric generation at other generation facilities. To the extent that changes in the Dispatch of generation may result in the reduction of the transmission constraint affecting the delivery of Contract Energy from the Facility to the Point of Delivery, PSCo shall limit generation at generation facilities owned by PSCo or generation facilities that by contract are subject to Dispatch by PSCo to the extent necessary to enable Seller to deliver all or the maximum amount of Contract Energy generated by the Facility through the Point of Delivery. PSCo's obligation to Dispatch or otherwise limit generation to reduce or eliminate a transmission constraint under this Section 6.1(B) shall apply even if ownership or operational control of PSCo's transmission facilities is transferred to another entity.

(C) If PSCo does not limit generation as set forth in Section 6.1(B), then PSCo shall pay Seller, in accordance with Exhibit G, for energy production which was not able to be delivered as Contract Energy during the hours that PSCo could have arranged, but did not arrange, for the Dispatch of generation as required by Section 6.1(B). Payment shall be at the Contract Energy Payment Rate specified in Section 8.2, plus an additional amount equal to the value of PTCs lost (on an actual after tax basis) on the kilowatt hours of energy not delivered as Contract Energy during such hours. To receive payment for any energy that was not delivered as Contract Energy due to a constraint on PSCo's Transmission System as described in Section 6.1(B), Seller shall provide reasonable evidence of the number of megawatts of energy the Facility was capable of generating due to equipment condition during each hour of such constraint, never to exceed 162 MWh per hour or such lesser amount as certified pursuant to Section 4.7(C) to be the maximum nameplate capacity. Examples of the methodology for calculating the amount of energy not delivered as Contract Energy in the event PSCo does not comply with its obligations under Section 6.1(B) are set forth in Exhibit G. The Parties agree that payment by PSCo to Seller under this Section 6.1(C) shall constitute satisfactory substitute performance for PSCo's Dispatch commitments under Section 6.1(B) for the hours relating to such payment.

(D) Neither Seller nor PSCo shall curtail or interrupt the delivery or receipt of the Contract Energy for economic reasons. Except as provided in the last sentence of Section 6.1(C), nothing in this Section 6.1 shall limit PSCo’s liability for damages which may result from a PSCo Event of Default under this WESA.

Appendix VI

4. PUBLIC SERVICE COMPANY OF COLORADO 2004 RENEWABLE PPA

7.1 Sale and Purchase. Beginning on the Commercial Operation Date, Seller shall generate from the Facility, deliver to the Point of Delivery, and sell to PSCo, at the applicable price s set forth in Article 8, all Renewable Energy generated by the Facility. For the avoidance of doubt, except as otherwise expressly provided for herein, this REPA shall not be construed to constitute a 'take or pay' contract and PSCo shall have no obligation to pay for any energy that has not actually been generated by the Facility, measured by the Electric Metering Device(s), and delivered to PSCo at the Point of Delivery.

7.2 Committed Renewable Energy. Committed Renewable Energy is _____________megawatt hours (___________MWh) of Renewable Energy delivered to PSCo in any Commercial Operation Year. *[This is the annual amount of Renewable Energy bid in the proposal.]*

7.4 PSCo's Right to Curtail Renewable Energy. PSCo shall have the right to notify Seller, by telephonic communication from the SCC, to curtail the delivery of Renewable Energy to PSCo
from the Facility, and Seller shall immediately comply with such notification. PSCo may provide such
notification for any reason and in its sole discretion.

(A) Commencing on the Commercial Operation Date of the Facility, PSCo shall pay Seller for Renewable Energy delivered to PSCo by Seller to the Point of Delivery in a Commercial Operation Year up to one hundred fifteen (115%) at an energy payment rate equal to $ ________ ("Renewable Energy Payment Rate"). For all Renewable Energy delivered by Seller to PSCo at the Point of Delivery in a Commercial Operation Year which is in excess of one hundred fifteen percent (115% of the Committed Renewable Energy, PSCo shall pay Seller at an energy payment rate equal to fifty percent (50%) of the Renewable Energy Payment Rate. For avoidance of doubt, and except as specifically provided for under paragraph (B) below, PSCo shall not be obligated to make any payment to Seller under this Article 8 for any energy which, regardless of reason or event of Force Majeure affecting either Party, (i) does not qualify as Renewable Energy, (ii) is not measured by the Electric Metering Device(s) installed pursuant to Section 5.2, as such measurement may be adjusted pursuant to Section 5.3, or (iii) is not delivered to PSCo at the Point of Delivery.

(B) If delivery of Renewable Energy is curtailed by PSCo pursuant to Section 7.4 *[or if PSCo elects to utilize non-firm transmission service(s) to deliver Renewable Energy from the Point of Delivery to PSCo load and deliveries of Renewable Energy to PSCo are curtailed as a result of the curtailment of such non-firm transmission service(s) by the applicable transmission service provider]*, (i) the Parties shall use reasonable efforts to determine the quantity of Renewable Energy that would have been produced by the Facility had its generation not been so curtailed and (ii) PSCo shall pay to Seller (a) all amounts that Seller would have received from PSCo under this Agreement had production not been so curtailed and (b) the amount of any Tax Benefits to which Seller is entitled but does not receive, on a grossed up basis. Seller shall install sufficient measuring equipment at the Facility to collect data necessary to reasonably determine the amount of Facility generation subject to the aforementioned curtailment. In the event the Facility includes Wind Turbines, Seller shall install sufficient meteorological towers around the Site or in conjunction with the Wind Turbines to provide the capability of measuring and recording representative wind data 24 hours per day, which wind data shall be used to calculate any amounts due Seller under this paragraph (B). Notwithstanding the foregoing, and for avoidance of doubt, no payment shall be due Seller under this paragraph (B) for curtailments of delivery of Renewable Energy resulting from (i) an Emergency, (ii) any action taken by the Interconnection Provider under the Interconnection Agreement, (iii) any curtailment of firm transmission service by the applicable transmission service provider, arranged by either Party, to provide delivery of Renewable Energy to or from the Point of Delivery, or (iv) any notification from PSCo's SCC, pursuant to Section 7.4, requiring Seller to curtail deliveries of Renewable Energy if Seller has failed to maintain in full force and effect any permit, consent, license, approval, or authorization from any Governmental Authority required by law to construct and/or operate the Facility.

[Note to Wind Resource Bidders: *The availability of the PTC may impact the bid evaluation. While uncertainty exists as to whether the U.S. Congress will approve an extension of the PTC, which expired at the end of 2003, for purposes of this RFP, PSCo's working assumption is that the PTC will be extended through 2006. One of PSCo's goals in its Renewable Energy RPF is to evaluate and select renewable resources in time to take advantage of the PTC. Since the potential remains that PTCs will not be extended, PSCo requests the Renewable Energy Payment Rate be expressed both with and without PTC economic impact on Form D (attached to the RFP).]*

Appendix VI

5. SOUTHERN CALIFORNIA EDISON 2006 RENEWABLE PPA

1.01 Conveyance of Entire Output,
Conveyance of Environmental Attributes and Capacity Attributes.
Seller shall use best efforts and Prudent Electrical Practices to Schedule and convey the *entire* Delivered Amounts during the Term to SCE and SCE shall take delivery of such Scheduled Amounts.
In addition, Seller shall dedicate and convey any and all Environmental Attributes, Capacity Attributes and Resource Adequacy Benefits generated or produced by Seller during the Term to SCE and SCE shall be given sole title to all such Capacity Attributes, Environmental Attributes and Resource Adequacy Benefits.

If the Generating Facility is a biomass or landfill gas facility and Seller receives any tradable Environmental Attributes based on the greenhouse gas reduction benefits or other emission offsets attributed to its fuel usage, it shall provide SCE with sufficient Environmental Attributes to ensure that there are zero net emissions associated with the production of electricity from the Generating Facility.]

{SCE Comment: Biomass and biofuel only.}

Seller shall, at its own cost, take all actions and execute all documents or instruments necessary to effectuate the use of the Capacity Attributes, Environmental Attributes and Resource Adequacy Benefits for SCE's sole benefit throughout the Term.
Such actions shall include, without limitation:

(a) Cooperating with and encouraging the regional entity responsible for resource adequacy administration to certify or qualify the Contract Capacity for resource adequacy purposes;

(b) Testing the Generating Facility in order to certify the Contract Capacity for resource adequacy purposes;

(c) Complying with all current and future ISO tariff provisions that address resource adequacy, including but not limited to provisions regarding performance obligations and penalties; and

(d) Committing to SCE the full Contract Capacity.

SCE will have the exclusive right, at any time or from time-to-time during the Term, to sell, assign, convey, transfer, allocate, designate, award, report or otherwise provide any and all such Capacity Attributes, Environmental Attributes or Resource Adequacy Benefits to third parties; provided, however, any such action shall not constitute a transfer of, or release SCE of its obligations under this Agreement.

SCE shall be responsible for any costs associated with SCE's accounting for or otherwise claiming Environmental Attributes, Capacity Attributes and Resource Adequacy Benefits.
Seller shall convey title to and risk of loss of all Scheduled Amounts to SCE at the Delivery Point.
From the Effective Date, Seller shall not sell any Product to any entity other than SCE, except that:

(e) Seller shall have the right to sell into the ISO real-time market any electric energy generated by the Generating Facility before the beginning of the Term and Environmental Attributes and Capacity Attributes related to such electric energy generation, and to retain all proceeds of such sales; and

(f) In the event of an Extraordinary SCE Force Majeure, Seller may, but shall not be obligated to, sell the electric energy produced by the Generating Facility to a third party but such third party sales may take place only during the period that SCE is not accepting Seller's energy.

1.02 Seller's Energy Delivery Performance Obligation.

(a) Performance Requirements.
After the Firm Operation Date, Seller shall be subject to the following electric energy delivery requirements and damages for failure to perform as set forth below:

(i) Seller's *[Annual]* Energy Delivery Obligation.

Seller's Energy Delivery Obligation shall be equal to one hundred forty percent (140%) of the Expected Annual Net Energy Production[12] identified in Section **Error! Reference source not found.**.

{SCE Comment: Intermittent only.}

Seller's Annual Energy Delivery Obligation shall be equal to ninety percent (90%) of the Expected Annual Net Energy Production identified in Section **Error! Reference source not found.**.

{SCE Comment: Base Load only.}

(ii) Event of Deficient Energy Deliveries.

At the end of each Term Year commencing with the end of the second Term Year, if the sum of Seller's Metered Amounts plus any Lost Output in the twenty (24) month period immediately preceding the end of the applicable Term Year does not equal or exceed Seller's Energy Delivery Obligation, *then* an "Event of Deficient Energy Deliveries" shall be deemed to have occurred.

[12] Please note that the delivery period for this requirement is 24 months. See: Section 1.02(a)(ii), below.

{SCE Comment: Intermittent only.}

At the end of each Term Year if the sum of Seller's Metered Amounts plus any Lost Output during the Term Year does not equal or exceed Seller's Annual Energy Delivery Obligation, *then* an "Event of Deficient Energy Deliveries" shall be deemed to have occurred.

{SCE Comment: Base Load only.}

(b) Energy Replacement Damage Amount.

If an Event of Deficient Energy Deliveries occurs, as determined in accordance with Section 1.02(a)(ii) above, the Parties acknowledge that the damages sustained by SCE associated with Seller's failure to meet Seller's *[Annual]* Energy Delivery Obligation would be difficult or impossible to determine, or that obtaining an adequate remedy would be unreasonably time consuming or expensive, and therefore agree that Seller shall pay SCE as liquidated damages the "Energy Replacement Damage Amount," which is intended to compensate SCE for Seller's failure to perform, irrespective of whether SCE actually purchased such replacement electric energy by reason of Seller's failure to perform.

Within ninety (90) days after the end of the applicable Term Year, SCE shall calculate any Energy Replacement Damage Amount as set forth in Exhibit F, and shall provide Notice to Seller of any Energy Replacement Damage Amount owing, including a detailed explanation of, and rationale for, its calculation methodology, annotated work papers and source data. Seller shall have thirty (30) days after receipt of SCE's Notice to review SCE's calculation and either pay the entire Energy Replacement Damage Amount claimed by SCE or pay any undisputed portion and provide Notice to SCE of the portion it disputes along with a detailed explanation of, and rationale for, Seller's calculation methodology, annotated work papers and source data.

The Parties shall negotiate in good faith to resolve any disputed portion of the Energy Replacement Damage Amount and shall, as part of such good faith negotiations, promptly provide information or data relevant to the dispute as each Party may possess which is requested by the other Party. If the Parties are unable to resolve a dispute regarding any Energy Replacement Damage Amount within thirty (30) days after the sending of a Notice of dispute by Seller, either Party may submit the dispute to mediation and arbitration as provided in Article Twelve.

(c) Continuing Obligations of Seller.

Notwithstanding any payment of an Energy Replacement Damage Amount, Seller shall remain obligated to convey all electric energy generated by the Generating Facility and all Environmental Attributes and Capacity Attributes to SCE during the Term, as provided in Section 1.01

and Resource Adequacy Benefits as provided in Section **Error! Reference source not found.**.

Exhibit F
Energy Replacement Damage Amount
**** SCE Comment: Intermittent only.****

In accordance with the provisions of Section 1.02, if in any Term Year Seller fails to meet Seller's Energy Delivery Obligation; then Seller shall be subject to an Energy Replacement Damage Amount penalty calculated as follows:

ENERGY REPLACEMENT DAMAGE AMOUNT =
[(A – B – C) x (D – E)] – [F + G + H]

Where:

A = Seller's Energy Delivery Obligation in kWh.
B = Sum of Metered Amounts over the relevant twenty-four (24) month period in kWh.
C = Sum of Lost Output over the relevant twenty-four (24) month period in kWh.
D = Simple average of the Market Price for all Settlement Intervals in the twenty-four (24) month period in $/kWh.
E = Energy Price in $/kWh (i.e., $/MWh/1000).
F = Energy Replacement Damage Amount calculated at the end of the previous Term Year, if any, in dollars.
G = Warranty Availability Lost Production Payments made by Seller for the current Term Year, if any, in dollars.
H = Warranty Availability Lost Production Payments made by Seller for the previous Term Year, if any, in dollars.

Notes:

1. In the above calculation, the result of "(D - E)" shall not be greater than five cents ($0.05) per kWh or less than two cents ($0.02) per kWh.
2. If the result of the calculation above is zero or less, Seller shall not be obligated to pay an Energy Replacement Damage Amount.
3. In no event shall SCE pay an Energy Replacement Damage Amount.

Appendix VI

6. SOUTHWEST ENERGY RENEWABLE PPA (2005)

"**Available Capacity**" means, for any hour, if the amount of Capacity set forth in the Dispatch Notice (the "**Dispatched Capacity**") is (a) equal to or greater than the Contract Capacity, then "Available Capacity" is equal to the actual Capacity amount (the "**Delivered Capacity**"), but not greater than the Contract Capacity, or (b) less than Contract Capacity, then "**Available Capacity**" is equal to the Contract Capacity less the amount by which the Dispatched Capacity exceeds the Delivered Capacity, if any.

IX. Seller's and Buyer's Obligations. A. Subject to, and in accordance with, the terms and conditions of this Agreement, Seller does hereby sell and Buyer does hereby purchase and agree to pay for the Dedicated Facility Capacity, and Seller does hereby sell and agrees to deliver, or cause to be delivered, and Buyer does hereby purchase and agree to pay for the Energy and Ancillary Services associated with the Dedicated Facility Capacity.

Buyer's purchase of the Dedicated Facility Capacity and associated Energy and Ancillary Services is exclusive. Buyer shall have the exclusive right to Dispatch and receive all of the Dedicated Facility Capacity and associated Energy and Ancillary Services and the exclusive right to (i) utilize the Energy and Ancillary Services associated with the Dedicated Facility Capacity and (ii) market the Dedicated Facility Capacity and the associated Energy and Ancillary Services. Seller shall not offer, sell or make available any Capacity, Energy or Ancillary Services associated with, or generated or capable of being generated from, the Dedicated Facility or Dispatch the Dedicated Facility to or for the benefit of any Person other than Buyer or its successors or permitted assignees.

Except to the extent the Dedicated Facility is actually unavailable or limited, Seller shall, regardless of whether the Available Capacity shall be, for any period, at, above or below the PS Target Availability or [*Baseload and Intermediate*: TMR], [*Peaking*: NPS] Target Availability, operate the Dedicated Facility to provide the Dedicated Facility Capacity and associated Energy and Ancillary Services in all hours in which Scheduled and Dispatched by Buyer. Seller agrees that, notwithstanding anything herein to the contrary, Seller will not curtail or otherwise reduce deliveries of the Dedicated Facility Capacity and associated Energy or Ancillary Services in order to make other sales of Capacity, Energy or Ancillary Services from the Dedicated Facility.

Seller shall not, directly or indirectly, use or employ, in connection with the sale of the Dedicated Facility Capacity and associated Energy and Ancillary Services or otherwise in connection with the performance of Seller's obligations hereunder, including Seller's obligations in respect of Availability Notices under Section 9.3 hereof, any manipulative or deceptive device or contrivance (as those terms are used in section 10(b) of the Securities Exchange Act of 1934) in contravention of any applicable law, including such rules and regulations as FERC may prescribe pursuant to Section 222 of the Federal Power Act.

X. Transmission and Scheduling. Seller shall make all Energy and Ancillary Services associated with the Dedicated Facility Capacity available to Buyer at the Delivery Point and shall Schedule or arrange for Scheduling services with its Transmission Providers to deliver or cause to be delivered all Energy and Ancillary Services associated with the Dedicated Facility Capacity at the Delivery Point. [Seller, to

the extent the Dedicated Facility is outside of SPP, shall arrange and be responsible for obtaining Firm Transmission Service, continuously at all times during the Delivery Period, for the delivery of all Energy and Ancillary Services associated with the Dedicated Facility Capacity to the Delivery Point.] **[***Note: If the Dedicated Facility is outside of the SPP RTO, then Seller will be required to obtain Firm Transmission Service to the SPP border. If the Dedicated Facility is in the SPP RTO, then Seller will not be required to obtain Firm Transmission Service (regardless of whether the Dedicated Facility is in Buyer's SPP control area or another control area). If the Dedicated Facility is in the SPP RTO but not in Buyer's SPP control area, then certain Ancillary Service charges may be imposed by the Dedicated Facility's host control area and Seller will be responsible for such charges pursuant to the next sentence.***]** **Buyer shall arrange and be responsible for transmission service at and from the Delivery Point and shall Schedule or arrange for Scheduling services with its Transmission Providers to receive all Energy and Ancillary Services associated with the Dedicated Facility Capacity at the Delivery Point. Seller shall be responsible for (a) all costs or charges imposed on or associated with the Dedicated Facility Capacity and associated Energy and Ancillary Services and delivery of all Energy and Ancillary Services associated with the Dedicated Facility Capacity up to the Delivery Point and (b) any and all Imbalance Charges; provided, however, that any such Imbalance Charges resulting directly from Buyer's unexcused failure to receive Delivered Energy associated with the Dedicated Facility Capacity that is Scheduled and Dispatched by Buyer in an effective Delivery Notice shall be the responsibility of Buyer. Buyer shall be responsible for all costs or charges imposed on or associated with the Dedicated Facility Capacity and associated Energy and Ancillary Services and the delivery of all Energy and Ancillary Services associated with the Dedicated Facility Capacity at and after the Delivery Point.**

XI. Replacement Power. In the event Seller is unable, due to an Unplanned Outage, to make Energy or Ancillary Services associated with the Dedicated Facility Capacity available at the Delivery Point in accordance with the then effective Dispatch Notice, Seller may deliver Replacement Power at the Delivery Point, but only with Buyer's consent (which may be given telephonically, but confirmed in writing as soon as practicable) and only on such terms and conditions as the Parties shall agree. Seller shall arrange and be responsible for firm transmission to the Delivery Point, shall make all Replacement Power available to Buyer at the Delivery Point and shall Schedule or arrange for Scheduling services with its Transmission Providers to deliver all Replacement Power at the Delivery Point.

XII. A. Operating Limitation. Buyer may provide a Dispatch Notice to Seller and receive Energy or Ancillary Services associated with the Dedicated Facility Capacity upon advance notice delivered (i) prior to the time in which such Energy or Ancillary Services is to be delivered and (ii) consistent with the Operating Parameters.

Turndown. When a Dispatch Notice requires the quantity of Energy or Ancillary Services to be reduced, such Dispatch Notice shall be delivered (i) prior to the time in which the delivery of such Energy or Ancillary Services is to be reduced and (ii) consistent with the Operating Parameters.

Start-ups. In respect of each Cold Start, Warm Start and Hot Start of each Unit (including for purposes of this Section 3.2(c) any uncompleted Start-up canceled by Buyer more than [[ ] hours [*Baseload*]] [[ ] hours [*Intermediate*]] [[ ] hours [*Peaking*]] after the time of [*describe initial startup characteristic feature*] but excluding any uncompleted Start-up otherwise canceled) required by a Dispatch Notice delivered by Buyer to Seller following a shutdown of such Unit pursuant to a Dispatch Notice, Buyer shall pay the applicable Start-up payment set forth in Schedule 3.2(c). All Start-up costs in respect of any Cold Start, Warm Start or Hot Start of an Unit not following a shutdown a Unit pursuant to a Dispatch Notice shall be for the account of Seller.

XIII. Unit Contingent. All Energy and Ancillary Services associated with the Dedicated Facility Capacity and all of Seller's obligations to sell and deliver Energy and Ancillary Services associated with the Dedicated Facility Capacity are Unit Contingent. The burden of establishing the existence and extent of any Unit Contingency shall be on Seller.

Payment for Dedicated Facility Capacity. For each calendar month during the Delivery Period, Buyer shall pay Seller an amount (the "Capacity Payment**") equal to the product of (a) the Fixed Payment Price multiplied by (b) the Contract Capacity multiplied by (c) the Availability Adjustment multiplied by (d) the FM Adjustment.**

Determination of the Availability Adjustment. The Availability Adjustment shall be determined in the following manner:

[*Peaking Only*]

Target Availability. Seller and Buyer agrees that the target availability (i) for each month in the Peak Season (the "PS Target Availability") shall be [ ]% and (ii) for each month in the Non-Peak Season (the "NPS Target Availability") shall be [ ]%.

Availability Adjustment. 1. The Availability Adjustment in respect of each month of the Delivery Period that Buyer Dispatched or attempted to Dispatch the Dedicated Facility shall be calculated as follows and expressed as a percentage (rounded to the nearest one-hundredth of one percent):

$$\textit{Availability Adjustment} = 100\% - \max(0, [TA - AA])$$

where,

TA	=	PS Target Availability in respect of the Peak Season or NPS Target Availability in respect of the Non-Peak Season, as applicable
AA	=	$\sum_{i=1}^{DHOM} \frac{ACAP_i + RP_i}{(DHOM \times CC) - AC_i}$
$ACAP_i$	=	Available Capacity for each hour that Buyer Dispatched or attempted to Dispatch the Dedicated Facility
AC_i	=	Affected Capacity for each hour that Buyer Dispatched or attempted to Dispatch the Dedicated Facility
RP_i	=	Replacement Power for each hour that Buyer Dispatched or attempted to Dispatch the Dedicated Facility
$DHOM$	=	Total hours that Buyer Dispatched or attempted to Dispatch the Dedicated Facility in the given month
CC	=	Contract Capacity

The Availability Adjustment in respect of each month of the Delivery Period that Buyer did not Dispatch or attempt to Dispatch the Dedicated Facility shall be equal to 100%.

Determination of FM Adjustment. In any month in which any portion of the Dedicated Facility Capacity is not available due to a Force Majeure event during any hour that Buyer Dispatched or attempted to Dispatch the Dedicated Facility, the FM Adjustment shall be determined as follows (rounded to the nearest one-hundredth of a percent):

$$FM\ \ Adjustment = 100\% - \frac{\sum_{i=1}^{DHOM} FMAC_i}{DHOM \times CC}$$

where,

$FMAC_i$	=	Affected Capacity, other than Affected Capacity resulting from Planned Outages, for each hour that Buyer Dispatched or attempted to Dispatch the Dedicated Facility
$DHOM$	=	Total hours that Buyer Dispatched or attempted to Dispatch the Dedicated Facility in the given month
CC	=	Contract Capacity

[*Baseload and Intermediate Only*]

Target Availability. Seller and Buyer agrees that the target availability (i) for each month in the Peak Season (the "PS Target Availability") shall be [ ]% and (ii) for each month on a twelve-month rolling basis (the "TMR Target Availability") shall be [ ]%.

Availability Adjustment. 2. The availability adjustment in respect of the PS Target Availability (the "PS Availability Adjustment") for each month shall be calculated as follows and expressed as a percentage (rounded to the nearest one-hundredth of one percent):

$$PS\ Availability\ Adjustment = \max(0, 100\% - 2[PSTA - AA])$$

where,

$PSTA$	=	PS Target Availability
AA	=	$\sum_{i=1}^{HOM} \frac{ACAP_i + RP_i}{(HOM \times CC) - AC_i}$
$ACAP_i$	=	Available Capacity for each hour
AC_i	=	Affected Capacity for each hour
RP_i	=	Replacement Power for each hour

HOM	=	Total hours in a month
CC	=	Contract Capacity

The availability adjustment in respect of the TMR Target Availability (the "TMR Availability Adjustment") for each month shall be calculated as follows and expressed as a percentage (rounded to the nearest one-hundredth of one percent):

$$TMR\ Availability\ Adjustment = \max(0, 100\% - 2[TMRTA - TMRAA]$$

where,

$TMRTA$	=	TMR Target Availability
$TMRAA$	=	$\sum_{j=1}^{Rolling\ Twelve\ Months} \frac{\sum_{i=1}^{HOM} \left[\frac{ACAP_i + RP_i}{(HOM \times CC) - AC_i} \right]_j}{12}$
$ACAP$	=	Available Capacity for each hour
AC	=	Affected Capacity for each hour
RP	=	Replacement Power for each hour
HOM	=	Total hours in a month
CC	=	Contract Capacity

The Availability Adjustment shall be the greater of (x) the PS Availability Adjustment and (y) the TMR Availability Adjustment.

<u>Determination of FM Adjustment</u>. In any month in which any portion of the Dedicated Facility Capacity is not available due to a Force Majeure event, the FM Adjustment shall be determined as follows (rounded to the nearest one-hundredth of a percent):

$$FM\ Adjustment = \left[100\% - \frac{\sum_{l=1}^{HOM} FMAC_i}{CC \times HOM} \right]$$

where,

$FMAC_i$	=	Affected Capacity, other than Affected Capacity resulting from Planned Outages, for each hour
CC	=	Contract Capacity
HOM	=	Total hours in the applicable month

Determination of the Energy Payment. For each calendar month during each Contract Year, Buyer shall pay Seller an amount (the "Energy Payment") equal to the following:

[*Baseload Option A]:*

$$Energy\,Payment = \sum_{i=1}^{HOM} (Energy\,Price + VPP) \times (DE_i + RP_i)$$

where,
Energy Price = $[]/MWh
DE_i = Delivered Energy for each hour
RP_i = Replacement Power for each hour
VPP = Variable Payment Price

[*Baseload Option B*: *Bidder to provide*.]

[*Intermediate and Peaking Options]*:

$$Energy\,Payment = \sum_{i=1}^{HOM} ((GI_i \times HR_i) + VPP) \times (DE_i + RP_i)$$

where,
GI_i = Gas Index for each hour
HR_i = Heat Rate for each hour
VPP = Variable Payment Price
DE_i = Delivered Energy for each hour
RP_i = Replacement Power for each hour
HOM = Hours in the applicable month

Heat Rate. The heat rate of Energy and Ancillary Services associated with the Dedicated Facility Capacity at full load operating capability and at partial loads (other than as the result of, or in connection with an Unplanned Outage) is set forth in Schedule 5.3(a).

Excess Delivered Energy. Delivered Energy in excess of the quantity of Delivered Energy specified by Buyer in a Dispatch Notice but not exceeding two percent (2%) of such quantity shall be considered Delivered Energy, the determination of the Energy Payment shall include such excess, and all revenues received by Seller in respect of such excess shall be remitted to Buyer. Delivered Energy exceeding two percent (2%) of the quantity of Delivered Energy specified by Buyer in a Dispatch Notice shall not be considered Delivered Energy, the determination of the Energy Payment shall not include such excess, and all revenues received by Seller in respect of such excess shall be remitted to Buyer.

Ancillary Services Associated with the Dedicated Facility. The Parties understand and agree that the cost of Ancillary Services associated with the Dedicated Facility Capacity that are requested and delivered in accordance with regular Dispatch of the Dedicated Facility in accordance with this Agreement is included in and compensated for by the Capacity Payment described in Section 5.1 and the Energy Payment described in Section 5.3.