Integrated Resource Plan

Appendix 7H

Technical Advisory Committee – Written Submissions on Consultation Topics 2012

About the IRP Technical Advisory Committee

An IRP Technical Advisory Committee (TAC) was established by BC Hydro in December 2010 to provide detailed technical input and feedback to assist BC Hydro in creating a thorough and well-considered Integrated Resource Plan (IRP). This advisory input is in addition to input provided by the public, First Nations, and stakeholders through the province-wide, IRP consultation process.

The Committee membership consists of knowledgeable participants with a significant stake, interest and experience in BC Hydro's resource planning process. Members of the Committee include representatives from the public, First Nations and stakeholders. The Terms of Reference details the purpose, mandate, roles and responsibilities and process management aspects of the Committee's work. The Committee met periodically throughout the development of the IRP to review the technical inputs to the analysis, the results of the analysis, and ultimately the draft IRP. Meeting agendas, presentations and supporting materials can be found at www.bchydro.com/irp under Document Centre.

Written Submissions on Draft IRP

As stated in the IRP TAC's Terms of Reference, "At key junctures during the process, committee members will be asked to provide attributed comments to BC Hydro on core planning topics of the IRP to form part of the consultation record."

At TAC Meeting #6 held June 18, 2012, TAC members were introduced to the draft plan and provided with an opportunity to ask questions and seek clarification on the draft plan. At that meeting, TAC members were requested to submit individual, written comments on the draft IRP and were advised that feedback would be considered along with feedback collected from First Nations and public and stakeholder consultation, as BC Hydro finalized its plan for submission to government by December 3, 2012.

Submissions received are attached in the following order:

- Association of Major Power Consumers (Richard Stout)
- First Nations Energy and Mining Council (Andrew McLaren)
- Fortis BC (Ken Ross)
- Clean Energy Association of BC (Loch McJannett)
- Commercial Energy Consumers (David Craig)
- The Pembina Institute (Matt Horne)
- BC Sustainable Energy Association (Tom Hackney)
- Attachments to BC Sustainable Energy Association submission*

** Because of their lengths, these attachments can be found in a separate document at www.bchydro.com/irp under Document Centre.*

WRITTEN SUBMISSION FROM:

ASSOCIATION OF MAJOR POWER CONSUMERS

Association of Major Power Customers of BC

August 10, 2012

Anne Wilson
BC Hydro Integrated Resource Planning
333 Dunsmuir St., Vancouver BC V6B 5R3

Dear Ms. Wilson:

I write further to BC Hydro's invitation to Technical Advisory Committee (TAC) members to provide comments on BC Hydro's draft Integrated Resource Plan (IRP). I also write in response to the email of Kristin Hanlon, dated July 26, 2012, responding to my July 10, 2012 questions (copies of each are attached for your convenience).

AMPC is unable to provide significant substantive comments on the draft IRP at this time given BC Hydro's inability to reconcile the draft IRP with:

- the Premier's June 21 announcement that LNG-related natural gas generation, including associated pipeline compression, will be deemed "clean" under the *Clean Energy Act*, and

- the associated *British Columbia's Energy Objectives Regulation*, which exempts electricity generated to serve facilities "that liquefy natural gas for export by ship" from the 93% clean generation ceiling established under the *Clean Energy Act.*

That announcement represents a tectonic policy shift that will fundamentally change much of the final IRP's content. To illustrate, Chapter 9 concludes with 14 recommended action items. Nearly half of those recommendations will change significantly as a result of the new policy. More specifically:

- Action 4 recommends pursuing Site C to add 5,100 GWh/yr (1,100 MW) as soon as possible.
    - This need and timing will obviously be significantly diminished and deferred by any actions taken to allow the 3,800 GWh (680 MW) of Initial LNG and the 12,800 GWh (1,700 MW) of LNG3 to be served by local natural gas-fired generation.

- Action 8 recommends a "North Coast Transmission Upgrade", consisting of reinforcing three 500 kV segments between Prince George and Terrace in time to meet Initial LNG facility load and mining loads.

- New natural gas-fired generation responding to *British Columbia's Energy Objectives Regulation,* presumably located on the North Coast and potentially turning Kitimat into a net exporter of electric energy, obviously affects this need.

- Action 9 recommends a 2,000 GWh/year Clean Procurement Option for projects to come into place in the F2017-F2019 timeframe.

  - Similar to the effects on Action 4, the need and timing for such energy sources would be significantly diminished and deferred by the potential addition of up to 16,600 GWh (2,380 MW firm) of LNG-related natural gas-fired generation.

- Action 10 suggests further investigating pumped storage, where pumped storage is considered as an alternative to natural gas given the lack of "headroom" in the 93% ceiling.

  - Pumped storage may now be evaluated against other options, such as Site C and the clean procurement options noted above and below, and it appears unlikely that pumped storage would be cost effective or worth investigating given the options available from the new regulation.

- Action 11 recommends new Peace River to North Coast Transmission, a new 500 kV line between Peace River and Prince George, and between Prince George and Terrace, related to LNG3 load.

  - The *British Columbia's Energy Objectives Regulation* will obviously materially affect the need for LNG3 to rely on system load and associated transmission developments.

- Action 12 recommends new Clean Energy Acquisitions for LNG3.

  - The *British Columbia's Energy Objectives Regulation* removes the need for this option.

- Action 13 recommends evaluating further natural gas-fired generation options.

  - Obviously, adding significant new natural gas-fired generation to supply LNG plant load would fundamentally affect this analysis, in terms of siting, potential economies of scale and partnerships, and other considerations.

Association of Major Power Customers of BC

AMPC urges BC Hydro to reconcile the draft IRP and the new gas-fired generation initiative, and looks forward to a robust and comprehensive plan, with an appropriate additional consultation process. If that step is not taken, however, the purpose of the existing consultation process will have been defeated.

Additionally, AMPC's July 10 questions reflect AMPC's expectation that the IRP demonstrate an open-minded approach that examines a spectrum of options with a view to clearly identifying associated costs and benefits, and then recommends the best solution from among them. AMPC's concern is that the IRP has been designed to showcase preferred outcomes that were a consequence of outdated energy policy directions. To be of value in uncertain times, an IRP must provide sufficient information and sufficient scenarios to accommodate and inform a spectrum of energy policy choices, in the same manner as it accommodates a spectrum of future load, supply and technology scenarios.

AMPC therefore recommends that additional development of the IRP should consider its July 10 questions, summarized as follows:

- Update natural gas price forecasts and ensure that IRP analyses take the updated price forecasts into account in its evaluations.

- Use natural gas as a marginal supply source (e.g., in relation to DSM economic evaluations, etc.) given the clearer availability of the space remaining under the 93% clean energy threshold following the passage of the *British Columbia's Energy Objectives Regulation*.

- To reflect *British Columbia's Energy Objectives Regulation*, revise the natural gas generation planning scenario in Section 6.5.3 to include a "Supply Option C", "Supply Option D", and "Supply Option E", consisting of combined cycle gas turbines (CCGTs) located at the North Coast to reflect LNG load, LNG load including pre-liquefaction compression and reserve generation, and LNG self-generation, respectively, including relative cost comparisons.

- Consider the effect of only applying the carbon tax to BC Hydro natural gas generation, without offset obligations.

- To identify relative costs associated with different policy options that may be selected from in the future, revise the natural gas generation planning scenario for a Kelly Lake facility in Table 6-12 to assume that all natural gas generation is

Association of Major Power Customers of BC

considered clean for the purpose of the CEA, and not only generation related to LNG export. Please also provide a cost comparison.

- Include a load forecast scenario that assumes that LNG loads and all natural gas processing and compression loads will meet their own energy needs in response to revised industrial tariffs and contribution policies.

- Evaluate and compare an "Option 6" in section 3.3 that is a bundled portfolio consisting only of those DSM programs that each individually satisfy the Rate Impact Measures test.

- Consider the cost of improved transmission south of the B.C.-U.S. border to repatriate the downstream benefits from the Columbia River Treaty, potentially as part of any 2014 renegotiation discussions, evaluate the effects on B.C.'s supply/demand balance.

Sincerely,

Richard Stout
Executive Director, Association of Major Power Customers of BC

cc: Rich Coleman, Minister of Energy
Charles Reid, CEO, BC Hydro

From: Hanlon, Kristin [mailto:Kristin.Hanlon@bchydro.com]
Sent: Thursday, July 26, 2012 10:24 AM
To: andrew@intergroup.ca; wjandrews@shaw.ca; dwcraig@allstream.net; doug.chong@bcuc.com; joe.mazza@terasengas.com; loch.mcjannett@cleanenergybc.org; matth@pembina.org; Reimann, Randy; roninconsult@live.com; Robert@hupacasath.ca; thackney@shaw.ca; Wallace, Brian; peterostergaard@shaw.ca; Jason.Wolfe@fortisbc.com; JQuail@cope378.ca; paul.wieringa@gov.bc.ca; Hoskins, Kenna
Cc: nicholasheap@canwea.ca; James, Loretta; Lee, Kathy; Stumborg, Basil; jweimer@telus.net; Gin, Jennifer; claire@marshallassociates.ca; moulton@litigationchambers.com; susancampbell@shaw.ca; Wilson, Anne; lwinstanley@cope378.ca; tompierrefs@pembina.org; jjlawson@telus.net
Subject: RE: BC Hydro IRP TAC Input

Dear TAC members:

As we are in the midst of vacation season, I am writing this response in lieu of Randy Reimann and Kenna Hoskins.

First I'd like to thank Richard for his letter dated July 10 requesting responses to questions on the Integrated Resource Plan (IRP).

To clarify, at the IRP Technical Advisory Committee (TAC) meeting on June 18, we invited any follow-up questions from TAC members for the purpose of clarifying the content of draft IRP. The majority of Richard's questions involve requests for additional analysis and/or revisions to the draft plan. We welcome such suggestions, but won't be considering them until the consultation process is complete.

Richard's question 1(a) is one I can presently address as a point of clarity. Government has indicated that any natural gas generation would be subject to either a carbon tax or an offset requirement, but not both. The Climate Action Plan says, "To avoid unfairness and what might effectively be double taxation, the carbon tax and complementary measures such as the 'cap and trade' system will be integrated as these other measures are designed and implemented."

After August 13, BC Hydro will be considering input received from public and stakeholders, First Nations and TAC members as it prepares the IRP for government, along with Tuesday's announcement by Minister Coleman that the Clean Energy Act has been updated to exclude LNG export facilities, and the electricity generation used to power them, from the 93 per cent clean and renewable energy requirement. At this point, it is too early to say what changes are needed to the draft IRP and to assess the consequences of such changes from a consultation perspective.

Subsequent to Richard's email, we have also received questions from Tom, which we will address under separate email next week.

I want to say that now, more than ever, TAC members' critical, considered input on the draft IRP will be valued by us, and I very much look forward to TAC members' individual, written feedback and suggestions on the draft IRP by Friday, August 10.

Sincerely,

Kristin Hanlon

Kristin Hanlon
Manager, Business Planning, Engagement & Regulatory

BC Hydro
333 Dunsmuir St., 10th Floor
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From: Richard Stout [mailto:roninconsult@live.com]
Sent: 2012, July 10 2:22 PM
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Cc: Hoskins, Kenna; nicholasheap@canwea.ca; James, Loretta; Lee, Kathy; Stumborg, Basil; jweimer@telus.net; Gin, Jennifer
Subject: RE: BC Hydro TAC Meeting #6 Confirmed for Monday, June 18 and Updates

Anne,

I have attached a letter outlining questions in "IR" form as discussed at the last TAC meeting. Given the impending policy changes it would be difficult to make useful comments without the requested information. It also seems to us that a longer timeframe for revision and comment would be advisable.

Regards,

Richard Stout

Executive Director
Association of Major Power Customers of B.C. (AMPC)

Tel: 604 366 4184

From: Anne.Wilson@bchydro.com
To: andrew@intergroup.ca; wjandrews@shaw.ca; claire@marshallassociates.ca; dwcraig@allstream.net; derek.griffin@gov.bc.ca; doug.chong@bcuc.com; joe.mazza@terasengas.com; loch.mcjannett@cleanenergybc.org; moulton@litigationchambers.com; matth@pembina.org; Randy.Reimann@bchydro.com; roninconsult@live.com; Robert@hupacasath.ca; thackney@shaw.ca; rbw@bht.com; peterostergaard@shaw.ca; Jason.Wolfe@fortisbc.com; susancampbell@shaw.ca; JQuail@cope378.ca; paul.wieringa@gov.bc.ca
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Subject: BC Hydro TAC Meeting #6 Confirmed for Monday, June 18 and Updates
Date: Tue, 29 May 2012 21:44:26 +0000

Association of Major Power Customers of BC

July 10, 2012

Anne Wilson
BC Hydro Integrated Resource Planning
333 Dunsmuir St., Vancouver BC V6B 5R3

Dear Madame:

I write further to the Technical Advisory Committee (TAC) meeting of Monday, June 18, 2012. That meeting discussed TAC comments and submissions in response to BC Hydro's draft Integrated Resource Plan (IRP).

I understand from the June 18 discussion that BC Hydro welcomes providing responses to TAC questions on the draft IRP to assist TAC members' drafting. The Association of Major Power Customers (AMPC) appreciates BC Hydro's offer, particularly in light of the subsequent June 21 announcement that natural gas generation will be considered "clean" if used in relation to LNG exports. AMPC suggests that the effect of that announcement is far-reaching and warrants a significant update to the draft IRP, following which the public, TAC and First Nations comment periods can resume.

Given that critical policy change is underway and more changes are likely within the next year and information contained in the IRP is of little value unless it is robust enough to inform this policy AMPC has developed the attached list of questions.

Please contact me if you have any questions concerning these questions. In light of the current August 10, 2012, deadline for TAC submissions, responses on or before July 20th, 2012 would be appreciated.

Sincerely

Richard Stout
Executive Director, Association of Major Power Customers of BC

Association of Major Power Customers of BC

1. Page 6-4 assumes that natural gas fired generation would be the subject of new regulations exempting it from the carbon tax, but would be subject to an obligation to develop or procure carbon-offsets. BC Hydro describes the carbon-offset market as "illiquid", however.

   a. Under status quo conditions, without further development of an offset policy or a carbon tax exemption regulation, is AMPC correct in understanding that new BC Hydro gas generation would be subject to the carbon tax only, and not both the offset and the carbon tax policies?

   b. Would it be possible for the provincial government to exempt BC Hydro from the offset policy instead of developing a carbon tax regulation exemption? Has BC Hydro discussed this possibility with its shareholder?

   c. How would a plant built in partnership with BC Hydro and LNG producers be treated?

2. The Premier announced on June 21, 2012, that natural gas would be deemed "clean" for the purpose of the *Clean Energy Act*'s (CEA) 93% threshold if the natural gas was used for the export of LNG – specifying liquefaction and associated pipeline compression. None of the natural gas generation planning scenarios considered in the IRP reflect this change.

   a. Please revise the natural gas generation planning scenario in Section 6.5.3 to include a "Supply Option C" and "Supply Option D" consisting of combined cycle gas turbines (CCGTs) located at the North Coast to reflect LNG load, and LNG self-generation, respectively. Please include a cost evaluation of each relative to the presented Supply Options A and B.

   b. Please revise the natural gas generation planning scenario for a Kelly Lake facility in Table 6-12 to assume that all natural gas generation is considered clean for the purpose of the CEA, and not only generation related to LNG export. Please also provide a cost comparison. While this request assumes a policy that is not currently in place, it will identify relative costs associated with different policy options that may be selected from in the future.

   c. Please indicate whether BC Hydro understands that natural gas generation developed to serve natural gas compression load in the Horn River and Montney areas can also be considered clean. In light of the

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current policy flux, please provide a qualitative and directional update to each of the Horn River and Montney load forecasts, and transmission forecasts.

3. Section 6.3.4.2 compares the cost-effectiveness of five DSM options described in section 3.3. Each option is a bundled portfolio that contains a different program mix and differing levels of cost effectiveness and rate impacts. AMPC supports DSM programs that are cost-effective, and is concerned about the rate impact of some DSM measures. AMPC therefore requests that BC Hydro evaluate and compare an "Option 6" that is a bundled portfolio consisting only of those DSM programs that each individually satisfy the Rate Impact Measures test. This will allow a better understanding of DSM option costs.

4. The natural long-term gas price forecasts used to develop expected costs of natural gas-fired generation date back to forecasts use to develop BC Hydro's 2008 LTAP and are higher than current long-term gas price forecasts. Please revise the IRP to include contemporary gas price forecasts.

5. Under the Columbia River Treaty BC Hydro has access to considerable "downstream benefits", but with the right of physical delivery limited by transmission constraints at the U.S. border. AMPC understands that the Columbia River Treaty may be renegotiated as early as 2014. Please provide a portfolio that considers the cost of improved transmission to repatriate the downstream benefits and the impact on supply/demand balance.

WRITTEN SUBMISSION FROM:

FIRST NATIONS ENERGY AND MINING COUNCIL

TECHNICAL ADVISORY COMMITTEE MEMBER

COMMENTS ON BC HYDRO'S

DRAFT INTEGRATED RESOURCE PLAN

Prepared on behalf of the First Nations Energy and Mining Council

Prepared by:

InterGroup Consultants Ltd.

500-280 Smith Street

Winnipeg, MB R3C 1K2

August 2012

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1.0 INTRODUCTION

This document summarizes comments of InterGroup Consultants Ltd. on BC Hydro's Draft Integrated Resource Plan (IRP). InterGroup participated as members of the Technical Advisory Committee for BC Hydro's IRP on behalf of the First Nations Energy and Mining Council (FNEMC). Comments reflect the review of the draft IRP and information presented to TAC members.

The IRP is BC Hydro's plan for obtaining the resources necessary to meet provincial electricity requirements for the next 20 years. Specific objectives for the IRP are set out in the *Clean Energy Act*. The Act requires BC Hydro to complete its IRP and submit it to the provincial government before the end of 2012. The IRP review process was delayed from its original schedule due to a provincial government review of BC Hydro rates that was announced in April 2011.

The IRP includes several components:

- A load forecast, which estimates how much electricity British Columbia will require over the next 20 years.
- Conservation initiatives that BC Hydro could pursue with its customers in order to reduce the amount of electricity that must be supplied.
- An evaluation of generation and transmission resources that could be acquired in order to meet the gap between existing resources and those required to serve future load growth.

BC Hydro examines each of these components under different potential future market scenarios, for example high or low future economic growth. Potential generation and transmission resources are evaluated across different indicators (or attributes) including cost, environmental impacts and economic benefits. The IRP concludes with several recommendations and actions for BC Hydro to pursue.

As part of the IRP process, BC Hydro established a Technical Advisory Committee (TAC). The purpose of the TAC was to provide ongoing feedback and expert advice to BC Hydro during the development of the IRP. BC Hydro has committed to considering input and advice from TAC members in developing the IRP. However, the IRP is BC Hydro's document and BC Hydro is not bound by recommendations or advice it receives from TAC members.

BC Hydro requested that the FNEMC participate as a member of the TAC. The FNEMC retained InterGroup Consultants Ltd. to participate on the FNEMC's behalf and to provide the FNEMC with a summary of comments and analysis following each TAC meeting. TAC meetings were held on December 14, 2010; January 27-28, 2011; February 14, 2011; April 5-6, 2011; February 28-29 2012; and June 18 2012. A draft of the IRP was prepared and circulated to TAC members in May 2012.

BC Hydro has requested that TAC participants provide public comments on the draft IRP. BC Hydro's draft IRP contains fourteen recommendations organized in four topic areas. BC Hydro has also provided a consultation feedback form with questions on each topic area. This document summarizes the comments of InterGroup Consultants on the four topic areas from a TAC participation perspective.

2.0 CONSERVE MORE

2.1 ISSUE SUMMARY

As part of the IRP process, BC Hydro prepared two mid-level 2011 load forecasts, one that includes what BC Hydro terms "initial LNG"[1] and one that excludes initial LNG. BC Hydro's IRP notes that a key objective of the *Clean Energy Act* is to reduce the expected increase in demand by 66 per cent by 2020. These reductions in forecast demand growth would be achieved through conservation programs or demand side management (DSM).

Conservation methods can take many forms: providing assistance to customers to purchase more efficient appliances and equipment; electricity rates that are designed to let customers know the full cost of electricity use and working with government to require higher energy efficiency standards for buildings and electrical equipment. BC Hydro's Draft IRP provides a description of five sets of options for conservation of energy that represent different approaches or packages of conservation options[2]. These options include: a slowing down of BC Hydro's current conservation planning (Option 1); maintaining the current conservation planning (Option 2); expanding efforts on current programs (Option 3); adding additional conversation programs (Option 4); and a fundamental shift in BC Hydro's conservation approach that emphasizes changes to market parameters and societal norms.

BC Hydro notes the DSM regulation directs the BCUC to use the Total Resource Cost (TRC) test to determine the cost-effectiveness of DSM options and prescribes certain elements of the TRC calculation. BC Hydro describes some concerns with elements of the TRC calculation and provides three versions of the calculation in the IRP: DSM gross cost per unit of energy savings; DSM net costs per unit of energy savings as estimated by BCH; DSM net costs per unit of energy savings using the methods prescribed in the DSM regulation.

The information provided by BCH in the IRP indicates that the gross costs of DSM programs for each of the five options range from a low of approximately $35/MWh (Option 1) to a high of approximately $50/MWh (Option 5). In all cases these average costs per MWh are substantially lower than BC Hydro's estimate of the long-run marginal cost of new renewable supply ($129/MWh). Using either of the approaches to estimate the "net cost" of DSM (either BC Hydro's approach or the approach prescribed in the DSM regulation) substantially reduces the cost estimates of DSM programming and therefore makes DSM programming appear even more cost effective relative to acquiring new renewable generation resources[3].

On the surface, the gap between the marginal cost of DSM programs ($35-$50/MW.h) and the marginal cost of acquiring new renewable generation resources ($129/MW.h) suggests there is substantial room

[1] The Douglas Channel and Kitimat LNG facilities. BC Hydro notes these facilities have obtained material government agency approvals including NEB export licenses and environmental assessment approvals. Further these facilities have requested service from BC Hydro. Page 2-2, BC Hydro Draft Integrated Resource Plan. May 2012.

[2] These are summarized in section 3.3 of the Draft IRP.

[3] Refer to pages 6-29 through 6-31 of the Draft IRP.

for BC Hydro to invest in even more aggressive DSM spending at a lower cost than acquiring new renewable generation. However, BC Hydro also notes in the IRP that:

1. There is a significant degree of uncertainty around a fixed resource plan's ability to hit its forecast targets several years out.
2. A number of elements have been identified as not being captured in the uncertainty quantification. A prudent approach to energy planning suggests that the quantified uncertainty estimates may understate the deliverability risk of DSM.
3. Options 4 and 5 are intrinsically different from Options 1 to 3 and show a substantial but uncertain upside[4].

BCH's Draft IRP also addresses capacity savings options, beyond the associated capacity benefits typically associated with the energy-focussed DSM options described above: industrial load curtailment and capacity focussed programs. BC Hydro notes these options represent its first major exploration of capacity-focussed DSM and as a result experience will be required to increase the certainty of potential or expected capacity savings associated with these programs.

2.1.1 Comments on BC Hydro Recommendations

Recommendation #1: Pursue DSM Option 3 and increase energy savings targets to 9,800 GW.h/year by F2021 (1,000 GW.h/year more than the current plan) through conservation and efficiency programs, incentives and regulations.

BC Hydro states that Option 3 would deliver electricity savings at an average unit net cost of less than $10/MWh compared to the average cost of new supply at $129/MWh. BC Hydro indicates it prefers Option 3 in part due to additional deliverability risks associated with Options 4 and 5. BC Hydro notes a key objective of the *Clean Energy Act* is the reduction of future demand by 66 percent. BC Hydro notes that Option 3 achieves 78 percent reduction in future demand for the consideration of Initial LNG, but only 58 per cent after initial LNG is included[5].

Based on the gross TRC information provided by BC Hydro in the draft IRP, it appears that the recommendation to pursue DSM Option 3 is reasonable and cost-effective relative to acquiring new renewable sources of supply. Other observations and comments include:

- The marginal cost gap between the gross cost of DSM and the marginal cost of acquiring new supply is large. BC Hydro notes there is uncertainty in the deliverability of DSM savings and that its recommendation is prudent. However, there are risks that BC Hydro's proposal will not maximize the potential cost advantages of DSM relative to new generation supply. BC Hydro should continue to monitor the costs and deliverability of DSM programs to ensure it has maximized its conservation potential.

[4] Pages 6-38 to 6-39. BC Hydro Draft Integrated Resource Plan. May 2012.
[5] Pages 9-28 to 9-29. BC Hydro Draft Integrated Resource Plan. May 2012.

- Access to DSM programming continues to be an issue for many First Nations. BC Hydro should ensure its DSM programs include options and programs that are accessible and appropriate for First Nations. This is particularly important for remote communities where the marginal cost of generation is substantially higher than on the integrated electricity system.

Recommendation #2: Advance DSM Options 4 & 5. Explore more codes, standards, and rate options for savings beyond the 9,800 GW.h/year target. This action supports the recently introduced Bill 32 (*Energy and Water Efficiency Act).*

BC Hydro's portfolio analysis indicates that Options 4 and 5 have the potential to deliver additional energy savings that are cost-effective. However, BC Hydro also notes these two options represent an intrinsically different approach to DSM from existing programs. BC Hydro also notes deliverability is an important consideration in recommending a DSM approach in a resource plan[6]. There appears to be merit in BC Hydro's recommendation to explore these DSM options.

Recommendation #3: Pursue voluntary capacity-focused conservation programs that encourage residential, commercial and industrial customers to reduce energy consumption during peak periods.

BC Hydro's load-resource balance indicates a capacity deficit in the mid-gap load resource balance beginning in approximately 2016 or 2017. A capacity gap of some degree[7] persists throughout the forecast period even after adjustments to acknowledge the potential additional capacity benefits of DSM option 3, Site C and additional renewable IPP generation[8]. BC Hydro has provided analysis that industrial load curtailment and capacity focused DSM programs could provide between 400 to 500 MW of capacity benefits to address this deficit at costs that are lower than costs associated with gas-fired generation or pumped storage (the marginal supply side capacity resources that might otherwise be used to address this deficit).

Based on the information provided, BC Hydro's recommendation seems reasonable. Other observations and comments include:

- The voluntary nature of these programs is important. BC Hydro should focus on developing and implementing voluntary programs and rate options that share the benefits of cost savings with customers that choose to participate.

- As with the energy focused DSM programs, access to these programs is important. BC Hydro should ensure cost-effective capacity reduction programs are accessible in First Nations communities as well as to residential, commercial and industrial customers.

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[6] Pages 6-38 to 6-39. BC Hydro Draft Integrated Resource Plan. May 2012.

[7] Approximately 1,000 MW by fiscal 2021, decreasing to approximately 200MW by fiscal 2022 once Site C comes in to service. Page 6-136. BC Hydro Draft Integrated Resource Plan. May 2012.

[8] Refer to Figure 6-28 on page 6-136 of BC Hydro Draft Integrated Resource Plan. May 2012.

2.1.2 Other Comments

In addition to the specific comments on BC Hydro's recommendations, the following comments and observations on conservation programming are noted:

- **Access to Conservation Initiatives:** Access to DSM/Conservation initiatives is a challenge for many First Nation communities – particularly those in rural and remote locations. BC Hydro needs to ensure its DSM programs are accessible and available to all First Nations communities. Relevant considerations in this regard include:
    - In First Nations communities housing costs and electricity bills may be paid by the Band and not the individual or family residing in the home. Therefore conservation programs involving financial incentives/assistance for repairs and upgrades or reduced electricity bills may not be as effective as in other communities.
    - Access to capital dollars for repairs and improvements to community facilities (both residential and commercial) may be limited compared to other communities.
    - Codes and standards applicable in First Nations communities may differ from provincial standards.
- **Funding for First Nation Community Energy Managers:** In recognition of the specific challenges associated with conservation/DSM initiatives in First Nations communities, BC Hydro and the Province of British Columbia should provide capacity funding for energy managers to support energy conservation in First Nations communities.

3.0 BUILD AND REINVEST MORE

3.1 ISSUE SUMMARY

BC Hydro's mid-2011 load forecast shows material energy and capacity deficits beginning in approximately F2017, assuming the initial LNG developments proceed and current DSM programs continue. The energy and capacity deficits are summarized in Table 1.

Table 1:
Energy and Capacity Deficits 2011 Mid-load Forecast After DSM with Existing, Committed and Planned Resources[9]

	F2017	F2021	F2026	F2031
Energy Deficit (GW.h)	-761	-4,935	-7,367	-12,478
Capacity Deficit (MW)	-935	-1,167	-1,697	-2,436

[9] Pages 2-31 and 2-32. BC Hydro Draft Integrated Resource Plan. May 2012.

These deficits can be reduced to some degree with increased conservation initiatives. However, the mid-scenario energy and capacity gaps will still require BC Hydro to acquire additional supply by 2017[10].

BC Hydro's resource planning and optimization analysis indicates that Site C would be selected as a cost-competitive resource at its earliest available in-service date in all market scenarios for the high-gap and mid-gap load resource balances. For the small-gap resource balance, Site C is not selected as a cost-competitive resource until later in the planning period in three market scenarios. In the other two market scenarios Site C is not selected at all during the planning horizon for the small-gap resource balance.

BC Hydro's analysis concludes that Site C continues to be a cost-effective resource compared to other clean resource options[11]. BC Hydro further notes that Site C provides other ancillary benefits including additional shaping and firming capability for new wind resources[12].

BC Hydro also notes the presence of capacity deficits throughout the planning period. While Site C and increased DSM can address some of these gaps, there remains a need for BC Hydro to acquire additional capacity resources. BC Hydro's IRP sets out several options for building additional capacity in its integrated system.

3.1.1 Comments on BC Hydro Recommendations

Recommendation #4: Build Site C to add 5,100 GW.h/year of annual energy and 1,100 MW of dependable capacity to the system for the earliest in-service date, subject to environmental certification and fulfilling of the Crown's duty to consult, and where appropriate, accommodate Aboriginal groups.

BC Hydro's IRP highlights the considerable energy and capacity deficits the utility will be facing in the next five to ten years. Site C is recommended by BC Hydro as a cost effective generation resource that helps address these gaps. BC Hydro provides a high level preliminary discussion of environmental and economic attributes of the project but these project attributes do not appear to materially influence the selection of Site C as a preferred resource. BC Hydro notes that Site C is currently in an environmental and regulatory review process[13].

Site C has been studied considerably more than other potential resource options. It has also already received attention from legislators and regulators (including being exempted from the requirement for a certificate of public convenience and necessity under the *Clean Energy Act*). The degree to which Site C has already been advanced highlights several challenges associated with the IRP process:

- Site C is a specific resource opportunity, while other resource options examined in the IRP are only portfolios of potential projects, they do not represent site-specific project opportunities. As a result,

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[10] In the event Initial LNG loads do not materialize, the mid-gap scenario shows surplus energy available until at least F2021. Capacity deficits would be reduced, but not eliminated, in the event initial LNG loads do not materialize.
[11] Page 6-50. BC Hydro Draft Integrated Resource Plan. May 2012.
[12] Page 9-38. BC Hydro Draft Integrated Resource Plan. May 2012.
[13] Page 9-39. BC Hydro Draft Integrated Resource Plan. May 2012.

there is generally a better ability to model the costs and potential effects of Site C relative to other opportunities.

- Site C occurs at a scale and involves an intensity of local and regional environmental effects that is dramatically different than other resource portfolios. The high level environmental attribute screening undertaken in the IRP does not satisfactorily address these differences in scale and intensity of effects.

Based on the information provided to the TAC the following additional comments related to Site C are provided:

- **Conflicts between provincial level planning and regional/local environmental impacts:** Site C highlights the conflict between provincial level energy planning and regional environmental impacts. In order to develop Site C, local First Nations and communities would be asked to bear significant impacts on lands and water. No decisions or plans to advance Site C should be made without meaningful consultation and accommodation with First Nations whose lands and waters would be impacted. The Green Energy Advisory Task Force Report similarly highlighted this issue and recommended the establishment of regional clean energy planning processes.

- **Full impacts of development must be understood:** The environmental attribute analysis in BC Hydro's IRP does not adequately consider the intensity of the effects associated with Site C.

- **Benefits must be shared:** If new projects, including Site C, can be developed in a manner that is acceptable to the impacted First Nations and communities, mechanisms must be in place to ensure the economic benefits of the project are shared fairly with the local communities. Benefit sharing must extend beyond simply offering short-term construction-related employment to local residents. Revenue sharing and project ownership must be included as benefits for local First Nations and communities. Best practices from other Canadian jurisdictions should be reviewed and incorporated into project planning and development[14].

Recommendation #5: Develop Revelstoke Unit 6. Begin work to allow the sixth generating unit at Revelstoke Generating Station to be built by F2019, adding 500 MW of peak capacity to the BC Hydro system.

and

Recommendation #7: Investigate and Advance Additional Resource Smart Projects. Continue to investigate and advance cost-effective Resource Smart projects to utilize the remaining, untapped capacity within BC Hydro's existing hydroelectric system.

BC Hydro's draft IRP indicates there is a significant need for additional capacity throughout the planning period. To the extent this capacity need can be addressed by additional development at existing facilities

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[14] As an example, the Nisichawayasihk Cree Nation participation in the Wuskwatim generation project in Manitoba and the proposed Keeyask Generating Station project in Manitoba.

(presuming associated cost benefits and reduced environmental impacts relative to new developments) these recommendations seem prudent and reasonable.

Recommendation #6: Bridging Capacity from Existing Resources. Fill the short-term peak capacity gap from F2016 to F2021 with a combination of market purchases first, power from the Columbia River Treaty second, and extending the existing back-up use of Burrard Thermal Generating Station, if required and as authorized by regulation.

BC Hydro indicates there are minimal costs associated with maintaining access to capacity through market transactions and the Columbia River Treaty. BC Hydro indicates it would only rely upon Burrard after the market and Columbia River Treaty options. BC Hydro also indicates these options reflect material cost savings relative to developing natural gas fired generation for capacity purposes[15]. BC Hydro's recommendation appears reasonable given the cost advantages and concerns about the short-term deliverability of other capacity options.

Recommendation #8: North Coast Transmission Upgrade. Reinforce the existing 500kV line from Prince George (Williston Substation) to Terrace (Skeena Substation) to meet new demand on the North Coast.

BC Hydro indicates this project is required by F2016 in order to meet the requirements of the initial LNG facilities[16]. BC Hydro states initial scoping is complete and consultations with First Nations and stakeholders are underway. The project appears prudent from a planning perspective, subject to BC Hydro obtaining the necessary environmental and other regulatory approvals.

4.0 BUY MORE

4.1 ISSUE SUMMARY

BCH's Draft IRP indicates that under the mid-Gap and Large-Gap scenarios there are energy supply deficits beginning in F2017 even after pursuing DSM Option 3. The energy deficits in the mid-Gap scenario increase to approximately 3,500 GW.h/year until the addition of Site C in the F2022 time-frame. Even with the addition of Site C, the energy deficits in the Mid-Gap scenario grow to approximately 2,000GW.h by approximately F2025 and 6,000 GW.h by F2031[17].

BC Hydro states that IPP generation is the "swing resource" used to address these energy deficits[18]. However, BC Hydro also notes that if the short-term energy gap between F2017 and F2022 is filled by long-term IPP contracts, there will be surplus energy once Site C comes into service. BC Hydro notes that an approach that meets the 2017-2022 energy gap using a mix of IPP contracts and reliance on market purchases can meet energy requirements at a lower cost while providing the required reliability. However

[15] Page 9-47. BC Hydro Draft Integrated Resource Plan. May 2012.
[16] Page 9-51. BC Hydro Draft Integrated Resource Plan. May 2012.
[17] Figure 6-19. BC Hydro Draft Integrated Resource Plan. May 2012.
[18] Page 6-86. BC Hydro Draft Integrated Resource Plan. May 2012.

BC Hydro notes that this approach would not meet self-sufficiency requirements for a two or three year period[19].

With respect to the IPP procurement process, BC Hydro notes that in 2010 it retained a consultant to undertake an independent review of BC Hydro's procurement practices. Recommendations made by that consultant included:

- Link the IRP process and procurement activities (i.e. the timing and level of need for new resources should be determined through the IRP process).
- Make the energy procurement process more transparent for all stakeholders.
- Implement smaller but more frequent energy procurements in the future[20].

BC Hydro notes the on-going risk that loads will either grow more slowly or more quickly than currently anticipated. In particular, load risks related to LNG developments could substantially affect BC Hydro's future generation requirements.

With respect to capacity requirements, BC Hydro has noted an additional need for both long-term and contingency capacity[21]. BC Hydro notes that natural gas generation is often used as a low-cost source of additional capacity. However, there are policy implications of relying on natural gas-fired generation (related to the clean energy targets). Therefore BC Hydro recommends additional consideration of other capacity options including pumped storage.

4.1.1 Comments on BC Hydro Recommendations

Recommendation #9: Develop 2,000 GW.h/year Clean Procurement Option. Design an energy procurement process to acquire about 2,000 GW.h/year from clean energy producers from projects that would come into service in the F2017 to F2019 timeframe.

BC Hydro notes that using a mixture of IPP resources and market purchases reduces the cost to ratepayers (relative to addressing the short-term energy gap entirely with IPP contracted energy) by approximately $350 million (PV)[22]. This is a considerable cost saving and appears prudent, despite the potential policy concerns related to not meeting the self-sufficiency target in the short-term. BC Hydro's proposed approach should be considered in the context of the substantial rate pressures currently experienced by customers (which will only increase with future load growth).

[19] Page 6-91. BC Hydro Draft Integrated Resource Plan. May 2012.
[20] Final Report on BC Hydro's Energy Procurement Practices. Merrimack Energy Group. 2011.
[21] Page 9-60. BC Hydro Draft Integrated Resource Plan. May 2012.
[22] Page 6-91. BC Hydro Draft Integrated Resource Plan. May 2012.

In developing its procurement process, BC Hydro should address the findings of the Merrimack report. In particular:

- Reducing the complexity of the bidding process and purchase agreements to permit better access for small-scale power projects.
- Implementing smaller but more frequent procurements to provide more certainty and allow more flexibility for project development.
- Use a mixture of procurement methods.

Similar recommendations were made in the Green Energy Advisory Task Force Report[23]. These changes should enhance the ability for First Nations to participate in the BC Hydro energy procurement processes. BC Hydro should also consider adjustments to its procurement processes and energy purchase agreements to accommodate projects in remote non-integrated communities.

Recommendation #10: Explore Pumped Storage capacity options that focus on reducing the lead time to in-service dates and where and how to site future pumped storage in the province, should they be needed.

BC Hydro's Draft IRP notes the need for additional capacity throughout the planning horizon, even with the addition of Site C. Pumped storage may be a feasible source of additional capacity. However, pumped storage represents a new approach to developing capacity resources. BC Hydro has indicated a preference for exploring pumped storage opportunities near existing major load centres (to minimize the need for additional transmission where feasible). BC Hydro estimates it may take 8 to 10 years to fully design, permit and build a large pumped storage facility[24]. BC Hydro notes a number of potential risks related to the deliverability and future need for pumped storage.

BC Hydro's feasibility assessment of pumped storage projects must consider the compatibility of these potential developments with First Nation land-use plans. BC Hydro's feasibility assessment should also address the potential for First Nation investment in these projects. This will require a collaborative approach with First Nations to ensure these interests are addressed in the planning process.

5.0 PREPARE FOR POTENTIALLY GREATER DEMAND

5.1 ISSUE SUMMARY

BCH's draft IRP examines regional load growth scenarios to assist in understanding the potential implications of large LNG and mining related loads in the North Coast and the integration of Fort Nelson in conjunction with electrification of the Horn River Basin in northeastern BC. Table 2 summarizes the potential energy and capacity deficits assuming expanded LNG and a high mining load scenario. Table 3 summarizes the potential energy and capacity deficits with the integration of Fort Nelson and

[23] In particular, scheduling regular, predictable calls for clean power to create investor certainty.
[24] Page 9-61. BC Hydro Draft Integrated Resource Plan. May 2012.

electrification of the Horn River Basin. Table 4 provides an estimate of the combined impact of these scenarios.

Table 2:
Energy and Capacity Deficits
High Mining Load and LNG3 Load Scenario[25]

	F2017	F2021	F2026	F2031
Energy Deficit (GW.h)	-2,292	-16,503	-22,088	-26,996
Capacity Deficit (MW)	-1,212	-2,679	-3,622	-4,335

Table 3:
Energy and Capacity Deficits
Integration of Fort Nelson and Electrification of Horn River Basin[26]

	F2017	F2021	F2026	F2031
Energy Deficit (GW.h)	-659	-6,303	-10,706	-16,688
Capacity Deficit (MW)	-928	-1,365	-2,171	-3,032

Table 4:
Illustrative Energy and Capacity Deficits
Combined High Mining, LNG3 and Electrification of Horn River Basin[27]

	F2017	F2021	F2026	F2031
Energy Deficit (GW.h)	-2,951	-22,806	-32,794	-43,684
Capacity Deficit (MW)	-2,140	-4,044	-5,793	-7,367

These are material resource gaps that would be challenging for BC Hydro to address. Both of these regions are located at the end of radial transmission lines. Therefore, BC Hydro's draft IRP discusses two broad options to serve these loads if they materialize:

- Integrated system generation resources and additional transmission infrastructure where required; and

[25] Page 2-35. BC Hydro Draft Integrated Resource Plan. May 2012.
[26] Page 2-39. BC Hydro Draft Integrated Resource Plan. May 2012.
[27] These estimates were prepared simply by summing the figures in Table 2 and Table 3.

- Local generation resources (i.e. generation sited near the new loads to reduce transmission requirements.

5.1.1 Comments on BC Hydro Recommendations

Recommendation #11: New Transmission Infrastructure from Peace River to North Coast. Undertake work to maintain the earliest in-service date for a new 500kV transmission line from Prince George to Terrace and Kitimat, and from the Peace River region to Prince George.

BC Hydro identifies three new 500 kV transmission projects that may be required to supply the North Coast region in the event LNG3 and new mining loads materialize:

- A new 500 kV transmission line from Williston substation near Prince George to the Skeena substation near Terrace;
- Two new 500 kV transmission lines from the Skeena substation to a new 500 kV substation near Kitimat; and
- A new 500 kV transmission line from the Peace Region to the Williston substation near Prince George.

BC Hydro notes that these lines would not be required in the event LNG3 loads do not materialize. However, if LNG3 development proceeds, the additional supply may be required by F2020. BC Hydro notes that while it has explored the possibility of local gas-fired supply to serve these loads, for now BC Hydro prefers to keep both supply options available[28]. Therefore BC Hydro recommends proceeding with the planning and approvals of these projects. BC Hydro notes the work will be undertaken at minimal relative costs and final decisions on the required timing will not be made until F2014 at the earliest once critical milestones for these potential new loads are reached[29]. BC Hydro's recommendation seems prudent and can be undertaken at minimal cost to ratepayers.

Recommendation #12: Develop Future Acquisitions for LNG3. Develop procurement options for additional clean energy resources, backed-up by gas-fired generation – located either in the North Coast or both in the North Coast and across the province – for energy that could be delivered in the F2020-F2021 timeframe, should it be needed.

and

Recommendation #13: Natural Gas-fired Generation to Provide Contingency Capacity Options. Explore natural gas-fired generation options to reduce the lead time to in-service dates and to develop an understanding of where and how to site such future resources in the province, should they be needed.

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[28] Page 9-65. BC Hydro Draft Integrated Resource Plan. May 2012.
[29] Pages 9-66-9-67. BC Hydro Draft Integrated Resource Plan. May 2012.

and

Recommendation #14: Monitor Fort Nelson/Horn River Basin Load and Supply. Continue to monitor the northeast natural gas industry and undertake studies to keep open electricity supply options, including transmission connection to the integrated system and local gas-fired generation.

BC Hydro recommends designing a procurement process, at an expected cost of approximately $2 million, to deliver adequate volumes of clean energy to meet the potential additional demands of LNG3 loads. BC Hydro notes one of the more probable risks it faces with respect to this recommendation is that it will not be able to generation sufficient interests from potential developers to meet the volume and commercial operation dates required to serve the potential LNG loads. However, BC Hydro is also at risk of making expenditures in advance of the need for new capacity being confirmed[30].

BC Hydro also recommends undertaking work to develop natural gas-fired contingency options that focus on reducing the lead-time to in-service dates for these generation options if required[31]. BC Hydro notes there has been little to no greenfield gas generation project development work has occurred in BC in decades and therefore siting of potential gas generation is a substantial issue. BC Hydro estimates the costs associated with this action are approximately $750,000 in F2013 and F2014[32].

Finally, BC Hydro recommends monitoring natural gas industry developments in the Horn River Basin. BC Hydro indicates it is premature to undertake significant supply actions in the near-term, but proposes to undertake studies to keep open supply alternatives including transmission connection to the system and local gas-fired generation. BC Hydro estimates the costs for these actions will be approximately $2-3 million in the near-term[33].

The potential new LNG developments represent a material load risk to BC Hydro. Acquiring the new generation and transmission infrastructure required to serve these loads would involve substantial costs for all ratepayers as well as environmental effects (related to both generation and transmission resources). The consequences of these potential loads are of sufficient scale to represent a major provincial policy concern, beyond what BC Hydro alone can be expected to address. BC Hydro's recommended actions may be prudent, but will not be sufficient alone to respond to the substantial public policy concerns related to these potential developments.

First Nations are currently experiencing negative impacts of climate change and support efforts and policies to stabilize and reduce greenhouse gas emissions. Natural gas development (including as a fuel for transportation and electricity generation) may have a role to play in long-term provincial energy planning and global greenhouse gas emissions reductions. These potential benefits need to be weighed against the potential environmental implications of evolving gas extraction technologies. Provincial policy directions in this area continue to evolve. BC Hydro needs to be able to contribute to the provincial policy

[30] Page 9-70. BC Hydro Draft Integrated Resource Plan. May 2012.
[31] Page 9-71. BC Hydro Draft Integrated Resource Plan. May 2012.
[32] Page 9-73. BC Hydro Draft Integrated Resource Plan. May 2012.
[33] Page 9-75. BC Hydro Draft Integrated Resource Plan. May 2012.

debate through timely and effective communications of the trade-offs in costs and benefits for ratepayers of pursuing expanded natural gas development.

6.0 COMMENTS ON PROCESS AND NEXT STEPS

BC Hydro's plan includes a chapter on consultation activities (Chapter 8), though in the draft plan only a brief outline of consultation activities is provided and summaries of inputs received to date are noted. In the final version of the IRP, BC Hydro should, at a minimum, provide a summary of the comments received, and indicate how these comments were addressed in the final IRP. BC Hydro is not obligated to comply with every request or comment received, but at a minimum should acknowledge the comments received and indicate when such comments could not be addressed.

BC Hydro provided a draft copy of the IRP in May 2012 and has requested comments from TAC participants by early August 2012. BC Hydro is required to file the completed IRP with the provincial government by late 2012. BC Hydro's proposed steps to finalize the IRP and incorporate final comments received from the TAC, First Nations, the public and stakeholders is not defined. BC Hydro should provide IRP participants with a timeline showing the anticipated steps between the submission of final comments and BC Hydro's submission of the final IRP to the provincial government.

Finally, BC Hydro's draft IRP states BC Hydro seeks approval from the B.C. Lieutenant Governor in Council pursuant to subsection 4(1)(a) of the *Clean Energy Act*. Section 4 (1)(a) of the *Clean Energy Act* provides that the Lieutenant Governor in Council may, by order, approve or reject the plan. However, the review process contemplated by the province, and the decisions or actions that may flow from any approvals are not clear. BC Hydro and the provincial government should provide timelines for review of the IRP and clearly communicate to the public and participants in the IRP process, the decisions and actions that will follow approval of the IRP.

WRITTEN SUBMISSION FROM:

FORTIS BC

FORTIS BC

FortisBC Comments to BC Hydro on the Draft 2012 Integrated Resource Plan - August 10, 2012

Introduction

BC Hydro has requested input from stakeholders in regard to its Draft 2012 Integrated Resource Plan (IRP) in a format provided in their Consultation Discussion Guide. As a major stakeholder in the delivery of energy to customers in BC and a member of the Technical Advisory Committee to BC Hydro's Integrated Resource Plan, FortisBC would like to provide the following comments and input. FortisBC has endeavored to follow the format of the Discussion Guide by providing comments under each of the headings as requested by BC hydro below, and notes that there are a number of important issues that do not lend themselves to a fulsome discussion within these headings. We are therefore also providing comments under an additional heading titled "Overall Comments".

Overall Comments

Electric Load Avoidance

During the BC Utility Commission's regulatory review of BC Hydro's 2008 LTAP, FortisBC (then Terasen Gas) described in detail in its final submission, the benefits of electric load avoidance (ELA) in helping to cost effectively meet the gap between both annual and peak electricity demand and supply for BC Hydro over the planning horizon. By practicing ELA approaches, BC Hydro can avoid the addition of load where another, more appropriate fuel exists for a given end use such as space and water heating. In contrast, the absence of an ELA approach indicates that BC Hydro is continuing to add electricity load for these end uses and then spending DSM funding to try to reduce these loads through Power Smart programs.

Fortis BC continues to believe that ELA should be an important part of BC Hydro's resource portfolio analysis and notes that consideration of ELA is absent from the Draft 2012 IRP. As such, we have included our 2008 LTAP Review Final Submission as Attachment A to these comments. FortisBC urges BC Hydro to review that submission again and consider ELA as a resource alternative in its 2012 IRP. The BC Clean Energy Act and the Province's new Natural Gas Strategy have both been brought forward since the completion of the 2008 LTAP regulatory proceeding, and Fortis believes that both the CEA and the Natural Gas Strategy provide a framework that support ELA activities by BC Hydro. Additional discussion is included below under the Discussion Guide topic of 'Recommendations for Conserving More.

Carbon and Natural Gas Price Forecasts

FortisBC notes that BC Hydro has taken steps to address the most recent developments in GHG policies both within and outside of BC in its range of GHG price forecasts, but continues to use natural gas price forecasts that were developed in 2010. The most recent developments in GHG policy referred to by BC Hydro in Chapter 4 of the Draft 2012 IRP resulted in the consideration of a carbon price of zero in its scenarios as a result of more recent policy actions.

Natural gas markets have continued to evolve since 2010 as the industry gains greater certainty on the full potential of the vast North American unconventional gas reserves. Although it is recognized that current price levels are not sustainable, the favourable supply picture accompanied with continued improvements in production costs and well productivity has resulted in lower prices forecasts over the long term. FortisBC believes that it will be a worthwhile process for BC Hydro to use more recent natural gas price forecasting data in its gas price forecast scenarios, just as it has considered more recent developments in carbon pricing in its GHG price forecast scenarios. Continuing to base a resource analysis on outdated gas price information is likely to place an unnecessary bias against natural gas resources as either an electricity generation option (discussed in Chapter 6 of the draft IRP) or as one of several ELA opportunities.

Recognition that actions in BC can help to reduce GHG emissions beyond the Borders of BC

The Clean Energy Act of 2010 sets the Provincial objective to pursue fuel switching activities occur where carbon emissions are reduced within BC. The more recent Natural Gas Strategy and announcement from the BC government that it believes exports of natural gas will help to reduce global carbon emissions even though carbon emissions in BC may rise, is an acknowledgement by the government that activities should be sought out within BC can reduce carbon emissions beyond the Provincial Borders. Fortis BC believes that while the Clean Energy Act sets out the Provincial objective of switching from high carbon to low carbon fuels, this recent recognition that natural gas does play a clean energy role in BC and around the world suggests that BC Hydro should examine the potential for ELA approaches that include natural gas as an alternative fuel. In this way, any renewable electricity conserved in BC might be made available for export to offset higher emission electricity generation in neighbouring jurisdictions, recognizing that export of clean electricity is also a policy set out in the Clean Energy Act.

The use of Natural Gas for Electricity Generation in BC and in Surrounding Jurisdictions

Growth in natural gas fired generation is expected across North America, including the Pacific Northwest, due to its ability to quickly replace coal fired generation and its ability to balance renewable resources. FortisBC recognizes that BC Hydro is bounded by Provincial regulation as to the amount of natural gas fired generation it can rely on to supply future electricity demand, and that BC Hydro has examined alternatives to ensuring it complies with the 93% clean requirement from the CEA within Chapter 6 of the IRP. BC Hydro has, however, limited the scenarios (Figure 6-3) in which gas-fired generation is examined to the mid-gap and Initial LNG scenarios only. FortisBC would like to see this analysis expanded to include more scenarios for resource gap, north Coast, DSM option, Site C and wind integration alternatives.

Further, with the BC government signaling that it recognizes the value of natural gas fired generation in reducing global carbon emissions, FortisBC believes that the definition of clean energy needs to be changed so that all gas generation is consistent with the new definition for gas generation for LNG exports. As such, a non-bounded examination of the potential for natural gas fired generation in BC is a worthwhile exercise and would help inform both the BC Government and Stakeholders. Such an examination should include the benefits of:

- the diversity of supply that additional gas fired generation would create,

- optimizing all existing energy infrastructure within and serving BC,
- the ability of BC renewable electricity exports to reduce regional carbon emissions,
- natural gas fired generation as a peaking resource and as a base load resource within BC, and
- the role that ELA can play in reducing carbon emissions on a regional basis given the expected growth in natural gas fired generation in the region.

Discussion Guide Topic Areas

FortisBC's remaining comments are set out according to BC Hydro's discussion guide topics.

BC Recommendations for Conserving More

"Increasing our energy savings target to 9,800 gigawatt hours per year by 2020 (1,000 gigawatt hours more than the current plan) through conservation and efficiency programs, incentives and regulations." Exploring more codes, standards and rate options for savings beyond the annual target of 9,800 gigawatt hours.

British Columbia's Energy Objectives are defined in Part 1, Section 2b of the Clean Energy Act, which include:

> *"…to take demand-side measures and to conserve energy, including the objective of the authority reducing its expected increase in demand for electricity by the year 2020 by at least 66%...*
> *…to ensure the authority's rates remain among the most competitive of rates charged by public utilities in North America…"*

FortisBC believes that ELA meets the objectives of the Clean Energy Act, and that given the provincial government's recent pronouncement of the clean attributes of natural gas in reducing global GHGs, ELA activities which result in natural gas use for thermal end uses also meet the intent of the government to use the right fuel for the right use at the right time.

"Electric Load Avoidance DSM", as referred to in the attached submission, involves the provision of cost-effective incentive payments to customers faced with a decision to install appliances to encourage the customer not to adopt electricity for end uses where electricity is not the most efficient energy source from a Total Resource Cost ("TRC") perspective. Electric Load Avoidance DSM incentives can be structured in a variety of ways, but have as a common objective to mitigate the potential for the customer to choose electricity as an energy choice for space and water heating, thereby adding load that must be served at BC Hydro's significant marginal cost of supply. It does not make sense to add electric heating and hot water load that must be served by adding costly new generation and transmission resources, only to subsequently expend ratepayer funds to attempt to induce those same customers to reduce their electricity usage for these end uses. It would be far better never to have attracted that electric heating and hot water load in the first place. Further, it would be more cost-effective for customers. Current natural gas rates for residential customers are around $8/GJ. BC Hydro's Tier 2 RIB rate is the equivalent of $28.33/GJ. Cost-effective incentives could be tested first in new construction and expanded to retrofits.

Just across the BC border in Washington State, Puget Sound Energy, a combined gas and electric utility, actively pursues Electric Load Avoidance. Puget Sound Energy offers fairly significant rebates to customers to convert from electric space and water to natural gas space and water heating.[1] They do so because it makes financial sense to add customers where they have capacity to do so – on the natural gas system – and avoid customers where they are capacity constrained – on the electric system. The same holds true in British Columbia.

The current situation is different to that in 2008; today we have the enactment of the Clean Energy Act, and subsequent designation of gas fired generating for LNG exports as clean. The rationalization for designating gas fired generation as clean for LNG exports is that the export of British Columbia's LNG will result in lower emissions in Asia. Given this argument, it is reasonable and logical to conclude that BC Hydro should also pursue Electric Load Avoidance DSM by encouraging the use of natural gas for end use heating applications, not only because it is a more cost efficient option for BC Hydro rate payers, but it can also result in lower carbon emissions in the Pacific Northwest and Alberta. Although the Clean Energy Act defines "demand side measure" such that the current definition specifically excludes rates, measures, actions and programs that would encourage a switch to an energy form such that the switch would increase greenhouse gas emissions in British Columbia, government has also recently established a position that takes a more global view of greenhouse gas emissions than just looking within British Columbia. In its LNG Strategy, government states that "climate change is a global issue".[2] Government has endorsed the use of natural gas to power the LNG facilities planned for British Columbia through an amendment to the Clean Energy Act, after Premier Clark stated in an address to the BC Business Council that natural gas for this use would be considered "clean". Thus we can conclude that with enough political will, the current definition of demand side measure in the Clean Energy Act could be amended to allow for Electric Load Avoidance DSM that includes the customer choosing natural gas over electricity for appropriate end-uses.

The starting place for the Government's analysis of whether Electric Load Avoidance DSM should be used to produce more efficient price signals must be its favourable impact on the rates paid by BC Hydro customers. From a total resource perspective, BC Hydro customers collectively stand to benefit from the pursuit of Electric Load Avoidance DSM identified as having a Total Resource Cost ratio of benefits to costs of more than one.

Encourage Less Consumption During Peak Demand

BC Hydro recommends pursuing voluntary conservation programs that encourage residential, commercial and industrial customers to reduce energy consumption during peak periods.

FortisBC agrees that conservation programs that help reduce peak electricity demand can be valuable. Since space heating load is peak load, FortisBC believes demand side management programs and other mechanisms that might be developed to encourage ELA can be among the most effective mechanisms in reducing peak demand. Peak demand reductions resulting from ELA activities will also be among the

[1] http://www.pse.com/savingsandenergycenter/ForHomes/Pages/Converting-to-Natural-Gas.aspx
[2] "Liquified Natural Gas: A Strategy for British Columbia". Government of British Columbia, xxx 2012, p. 7.

most assured reductions since the load is avoided from the outset, rather than based on programs that aim to reduce consumption after it has been added to the system. Please review the attached final submission from FortisBC (then Terasen Gas) in the 2008 LTAP regulatory proceeding for a full discussion of the importance of considering ELA in the BC Hydro IRP.

Build Site C Energy Project

BC Hydro recommends building Site C to add 5,100 gigawatt hours of annual energy and 1,100 megawatts of dependable capacity to the system for the earliest in-service date, subject to environmental certification and fulfilling the Crown’s duty to consult and, where appropriate, accommodate Aboriginal groups.

FortisBC discussed the issues of gas price forecasts and conducting a non-bounded examination of the benefits of natural gas-fired generation under the heading – “Overall Comments”. If updated gas price forecasts are used in the analysis of resource options, and if a non-bounded (by the 93% clean requirement) examination of gas-fired generation is conducted, gas fired generation could emerge as a lower cost resource than Site C. Site C also has significant environmental, social and First Nations impacts that should be compared to site specific gas-fired generation in a more complete and meaningful way. As a wholesale power customer of BC Hydro through RS 3808, FortisBC expects BC Hydro to investigate all cost effective options to keep rates down.

Take Advantage of Resource Smart Opportunities

BC Hydro recommends beginning work to allow the sixth generating unit at Revelstoke Generating Station to be built by 2018, adding 500 megawatts of peak capacity to the BC Hydro system.

BC Hydro recommends continuing to investigate and advance cost-effective Resource Smart projects to utilize the remaining untapped capacity within BC Hydro’s existing hydroelectric system.

In addition to looking at other resource options, FortisBC supports BC Hydro continuing to investigate and advance cost-effective Resource Smart projects.

Combine Readily Available Resources to Meet the Short-term Capacity Gap

BC Hydro recommends filling the short-term peak capacity gap from 2015 to 2020 with a combination of market purchases first, power from the Columbia River Treaty second, and extending the existing backup use of Burrard Thermal Generating Station, if required and as authorized by regulation.

FortisBC discussed the issue of a more fulsome examination of natural gas fired generation as a resource option under the heading “Overall Comments”. Such an examination should include consideration of Burrard Thermal based on the BC Government’s pronouncement that natural gas fired generation supporting LNG exports is designated as clean and based on the BC government's recent Natural Gas Strategy. FortisBC believes that Burrard is a valuable resource for the customers of BC Hydro and its future use should be more completely articulated in the IRP. In addition there are other potential capacity options in the Province, such as the Waneta Expansion project, which can be used to meet this short-term capacity gap.

Reinforce Transmission

BC Hydro is recommending reinforcing the existing 500-kilovolt line from Prince George to Terrace to meet new demand on the north coast.

Transmission expansions can have significant ratepayer impacts. Given the new pronouncement by the Premier that natural gas fired generation for LNG plants on the north coast is now considered clean, it appears there may no longer be a need for this transmission reinforcement. The transmission reinforcement resource evaluation in the IRP should be re-freshed in light of regional gas generation options.

Energy from BC Based Clean Energy Producers

BC Hydro recommends developing energy procurement options to acquire up to 2,000 gigawatt hours from clean energy producers for projects that would come into service in the 2016–2018 time period.

For the reasons discussed above, FortisBC urges BC Hydro to consider evaluating its need for new clean resources under two additional conditions:

- What would be the need for additional resources if ELA DSM were implemented by BC Hydro, and
- What could the resource mix look like if all natural gas fired generation were treated consistently as clean electricity resources given the potential to offset coal fired electricity generation within the electricity trading region.

Natural gas fired generation cab produce firm energy throughout the year would provide the additional benefit of balancing non-firm renewable resources.

Potential Large Industrial Demand

BC Hydro recommends continuing to work with Liquefied Natural Gas (LNG) developers to understand their electricity requirements, and keep options open until further certainty on future requirements can be established.
Specifically:

- *Undertake work to maintain the earliest in-service date for a new 500-kV transmission line from Prince George to Terrace and Kitimat and from the Peace River region to Prince George.*

- *Develop procurement options for additional clean energy resources, backed up by gasfired generation (located only in the north coast, or in both the north coast and across the province) for electricity that could be delivered in the 2019 – 2020 timeframe, should it be needed.*

BC Hydro recommends continuing to monitor the northeast natural gas industry and undertake studies to keep electricity supply options open, including transmission connection to the integrated system, and local gas-fired generation.

FortisBC supports BC Hydro's recommendation to monitor the situation in the north and keep options open for being able to serve that demand. However, for the reasons discussed above with regard to the benefits of natural gas fired generation from a regional and global perspective, FortisBC urges BC Hydro to include consideration of natural gas fired generation across the Province for providing future electricity resources, and consider the potential benefits that ELA might have on deferring the need for such resources.

Peak Capacity Resources

BC Hydro recommends working with industry to explore pumped storage capacity options to reduce the lead time to in-service dates and to develop an understanding of where and how to site such future resources in the province, should they be needed.

BC Hydro recommends working with industry to explore natural gas-fired generation options to reduce the lead time to in-service dates and to develop an understanding of where and how to site such future resources in the province, should they be needed.

FortisBC supports BC Hydro working with industry to support both pumped storage and natural gas-fired capacity options in order to provide a current and more balanced comparison of these options to other capacity resource options. FortisBC also believes that it may be valuable for FortisBC and BC Hydro to jointly assess future requirements and consider options that may more efficiently meet the requirements of both electric utilities in the province on a combined basis.

FORTIS BC

Attachment A to FortisBC Comments on
BC Hydro Draft 2012 Integrated Resource Plan

Terasen Utilities' Submission to the BCUC, dated April 27th, 2009 with respect to BC Hydro's 2008 Long Term Acquisition Plan

Matthew Ghikas
Direct 604 631 3191
Facsimile 604 632 3191
mghikas@fasken.com

April 27, 2009
File No.: 240148.00595/14797

BY ELECTRONIC FILING

British Columbia Utilities Commission
Sixth Floor, 900 Howe Street
Vancouver, BC V6Z 2N3

Attention: Erica M. Hamilton,
Commission Secretary

Dear Sirs/Mesdames:

Re: Terasen Utilities
An Application by BC Hydro and Power Authority for the Approval of 2008 Long Term Acquisition Plan

We enclose Submissions on behalf of the Terasen Utilities in respect of the above mentioned matter. Twenty hard copies of the Submissions will follow by courier.

Yours truly,

FASKEN MARTINEAU DuMOULIN LLP

[Original signed by Matthew Ghikas]

Matthew Ghikas

MTG/fxm
Enc

IN THE MATTER OF

THE UTILITIES COMMISSION ACT S.B.C 1996, CHAPTER 473

AND

AN APPLICATION BY BRITISH COLUMBIA HYDRO AND POWER AUTHORITY (BC HYDRO)

FOR THE APPROVAL OF 2008 LONG TERM ACQUISITION PLAN (2008 LTAP)

FINAL SUBMISSIONS OF

THE TERASEN UTILITIES

APRIL 27, 2009

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FOR THE APPROVAL OF 2008 LONG TERM ACQUISITION PLAN (2008 LTAP)

FINAL SUBMISSIONS OF THE TERASEN UTILITIES

APRIL 27, 2009

I. INTRODUCTION AND OVERVIEW

A. Introduction

1. BC Hydro faces a significant challenge in closing its forecasted load-resource gap. BC Hydro is to be commended for advancing a significant portfolio of cost-effective electric *load reduction* demand-side measures ("DSM") that will assist BC Hydro customers to reduce their electricity consumption. However, DSM can also be directed at electric *load avoidance*. Where energy source alternatives exist for particular end use applications, BC Hydro's resource analysis should extend to whether electricity is, in the words of the Energy Plan, the "right fuel, for the right activity, at the right time".[1]

2. "Electric Load Avoidance DSM",[2] as referred to in these Submissions, involves providing cost-effective incentive payments to customers faced with a decision to install appliances to encourage the customer not to adopt electricity for end uses where electricity is not

[1] The BC Energy Plan states: "It is important for British Columbians to understand the appropriate uses of different forms of energy and utilize the right fuel, for the right activity at the right time. There is the potential to promote energy efficiency and alternative energy supplemented by natural gas." See Exhibit C13-5, at 61.

[2] We have used the term "Electric Load Avoidance DSM" in these Submissions, rather than the term "fuel switching" to emphasize that the purpose of these measures is to avoid inefficient electric load. Also, the term "fuel switching" is subject to being misconstrued as referring exclusively to measures directed at existing customers that have already installed electric appliances, whereas new customers that have yet to install any appliances are also a key target of Electric Load Avoidance DSM.

the most efficient energy source from a Total Resource Cost ("TRC") perspective. Electric Load Avoidance DSM incentives can be structured in a variety of ways, but have as their common objective to mitigate the potential for the customer to choose electricity as an energy choice for particular end use applications, thereby adding load that must be served at BC Hydro's significant marginal cost of supply, based on (i) the prospect of paying electricity rates based to a significant extent on BC Hydro's embedded costs,[3] or (ii) any differential in capital cost between electric appliances and appliances using another energy source. The incentive leaves the customer free to make the choice as to the appropriate energy source for a particular application based on a more efficient price signal from a TRC perspective. The right energy source for a particular customer, for a particular application, in the customer's particular circumstances might be electricity, natural gas, or some other energy source.

3. The starting place for the Commission's analysis of whether Electric Load Avoidance DSM should be used to produce more efficient price signals must be its favourable impact on the rates paid by BC Hydro customers. The importance of examining BC Hydro's strategies to meet the growing load-resource gap from the perspective of BC Hydro's ratepayers is evident from the legislated requirement in the *Utilities Commission Act* ("UCA") for BC Hydro to explain in its LTAP why it intends to acquire new higher-cost supply rather than to pursue this cost-effective DSM.[4] From a TRC perspective, BC Hydro customers collectively stand to benefit from the pursuit of Electric Load Avoidance DSM identified as having a TRC ratio of benefits to costs of more than one. The new emphasis in the UCA on encouraging public utilities to pursue cost-effective DSM is realized by BC Hydro pursuing cost-effective Electric Load Avoidance DSM.

4. "Government's energy objective" in the UCA "to encourage public utilities to reduce greenhouse gas ["GHG"] emissions", which reflects the Province's overall support for mitigating climate change as outlined in the Energy Plan, is also a valid consideration in the assessment of Electric Load Avoidance DSM. The evidence in this proceeding supports the

[3] BC Hydro's Residential Inclining Block ("RIB") rate structure, which introduced a trailing block rate that moves towards BC Hydro's marginal cost of supply, helps to promote efficient energy choices by customers; however, as discussed later in these Submissions, many residential customers will see mostly the Step 1 rate, and the Step 2 rate will necessarily lag behind BC Hydro's true marginal supply cost.

[4] UCA, s. 44.1(2) (b), (f).

potential for cost-effective Electric Load Avoidance DSM to reduce GHGs on a regional basis. There are three equally compelling reasons why this is the case. Further, the end use consumption of natural gas in BC is already subject to a carbon tax, which provides price signals reflecting the cost of carbon much like BC Hydro's purchased carbon offsets will do for gas-fired electricity generation after 2016. BC Hydro should therefore regard Electric Load Avoidance DSM as a means of reducing (all else equal) electricity rates with confidence that Electric Load Avoidance DSM is consistent with government's interest in mitigating climate change.

5. The Terasen Utilities are encouraged by BC Hydro's apparent willingness to study further the potential for Electric Load Avoidance DSM.[5] The preferable approach to rejecting a part of the LTAP is for the Commission to identify key parameters of that initiative through its findings and directions in this proceeding. The Commission should require BC Hydro to file its next LTAP within 12 to 15 months of the Commission's decision in this proceeding, which represents a continuation of the two-year cycle between LTAP filing dates. BC Hydro should be directed to include in the next LTAP a proposal to pursue cost-effective Electric Load Avoidance DSM based on the outcome of its further study. Maintaining the current two-year regulatory cycle for BC Hydro's LTAP will help to ensure that pursuit of Electric Load Avoidance DSM does not languish while new, higher cost, supply initiatives (e.g. the Clean Call) proceed.

B. Organization of These Submissions

6. These submissions are organized as follows:

(a) Part II discusses the contribution of avoidable (space and water heating) load to the increasing load-resource gap faced by BC Hydro.

(b) Part III addresses the potential to avoid part of the load with cost-effective Electric Load Avoidance DSM.

(c) Part IV explains why the TRC test is appropriate for measuring the cost-effectiveness of Electric Load Avoidance DSM. It also describes the benefit to BC Hydro customers to pursuing cost-effective DSM in the form of rates that are

[5] See Transcript, Vol. 11, at 2038.

lower than they otherwise would have been in the absence of the Electric Load Avoidance DSM.

(d) Part V sets out the evidence regarding how the pursuit of cost-effective Electric Load Avoidance DSM can reduce overall GHG emissions on a regional basis.

(e) Part VI discusses how the current policy and legislative context supports the use of Electric Load Avoidance DSM to send efficient price signals to customers faced with a fuel choice for a particular application. It discusses why the policy arguments advanced by BC Hydro do not outweigh the demonstrated benefits associated with pursuing cost-effective Electric Load Avoidance DSM.

(f) Part VII contains a summary of findings supported by the evidence in this proceeding, as well as proposed Commission directives that should guide the further study of Electric Load Avoidance DSM and inputs in the next LTAP.

II. CHOICE OF ENERGY SOURCE AND BC HYDRO'S LOAD RESOURCE GAP

7. Electric Load Avoidance DSM represents an important opportunity to address a portion of the widening load-resource gap in a cost-effective manner. The following points are addressed in this Part:

(i) BC Hydro faces a difficult task in meeting its forecasted energy and capacity requirements, and attaining self-sufficiency. The load forecast in the LTAP may understate the load requirements given the potential for developments in areas such as electric plug-in vehicles.

(ii) Residential space and water heating, for instance, contributes significantly to BC Hydro's energy and capacity requirements. This creates the imperative for BC Hydro to send effective price signals to encourage its customers to make efficient fuel choices.

(iii) Cost-effective Electric Load Avoidance DSM can help to overcome inefficient price signals on a TRC basis arising from electricity rates based on embedded costs and differential capital costs, with the result that customers may choose an alternative to electricity as an energy source for particular end use applications.

A. Forecasted Energy and Capacity Shortfall and Implications for BC Hydro

8. BC Hydro's Evidentiary Update shows a forecasted energy resource deficit, before factoring LTAP initiatives, of 3,500 GWh in F2012, 7,700 GWh in F2016, 10,600 GWh in F2017, and 13,600 GWh in F2021.[6] BC Hydro acknowledges that the resource deficit is "a

[6] Exhibit B-10, Table 2-6.

significant gap to close."[7] The resource deficit to meet energy demand is increasing even with the DSM adjustment, from a 3,000 GWh shortage in F2017 and to 3,700 GWh in F2021. In F2027, BC Hydro predicts an energy shortfall of 19,100 GWh before 2008 LTAP actions and a 7,500 GWh shortfall after adjusting for DSM. Thus, even with adjustments from currently proposed DSM, the deficit between forecasted energy load and resource more than doubles within a ten-year span (from F2017 to F2027).[8]

9. The forecasted capacity resource deficit is 350 MW in F2012, 1,120 MW in F2016, 1,190 MW in F2017, and 1,720 MW in F2021.[9]

10. BC Hydro has identified several factors that may increase BC Hydro's energy requirements. First, although BC Hydro predicts DSM savings of 7,600 GWh for F2017, 9,900 GWh for F2021, and 11,600 GWh for F2027,[10] it also readily concedes that it "faces uncertainty with respect to . . . DSM savings."[11] Second, electrification of oil and gas facilities may add to the future load forecast.[12] Third, there exists the potential for significant load associated with electric plug-in vehicles.[13] Fourth, as discussed further below, since BC Hydro's load-resource balance assumes that in future years the percentage of residential customers with electric space and water heating will remain more or less as it is today (based on BC Hydro's billing data), BC Hydro's energy requirements will increase if existing customers switch to electric space and water heating during the next 20 years or if the capture rate for new customers increases materially during that time.[14]

11. These potential developments will also have capacity consequences.

[7] Transcript, Vol. 3, at 257.

[8] Exhibit B-10, Table 2-9.

[9] Exhibit B-10, Table 2-7.

[10] Exhibit B-10, Table 2-9.

[11] Exhibit B-10, at 24; Transcript, Vol. 3, at 258.

[12] Exhibit B-10, at 12; Exhibit C13-5, at 6.

[13] Exhibit B-10, at 11; Exhibit C13-5, at 6.

[14] Transcript, Vol. 3, at 259-260; Exhibit B-10, at 11-12; see also Exhibit C13-7, at 15, BC Hydro states that all residential spacing heating and water heating load migrating from other energy sources to electricity is a low probability.

12. BC Hydro's ability to close the load-resource gap in a timely manner is critical for BC Hydro to meet the requirement to reach self-sufficiency by 2016. Lower than anticipated DSM savings will mean, for instance, that "there would likely not be time to recover through standard acquisition process. This would likely result in BC Hydro relying on the Canadian Entitlement and other market contingency options, something that is contrary to Special Direction No. 10 to the BCUC."[15] The fact that it is easier to "ramp down" DSM than "ramp it up",[16] when combined with the implications for not achieving the expected DSM savings associated with BC Hydro's proposed DSM expenditures, suggests that BC Hydro should be pursuing cost effective Electric Load Avoidance DSM at this time, rather than waiting until closer to 2016.

B. Contribution of Residential Space and Water Heating Load to Load-Resource Gap

13. Electric space heating and water heating are notable contributors to BC Hydro's forecasted energy and capacity shortfall. The addition of new electric space and water heating customers, either in the form of new BC Hydro customers (i.e. new construction) or existing BC Hydro customers replacing their end-of-life gas appliances with electric appliances, will add incremental load.

(i) Differential Contribution to Energy and Capacity Requirements

14. Customers with electric space and water heating contribute disproportionately to BC Hydro's energy requirements relative to customers without electric space and water heating. Existing customers with non-electric space and water heating consume about 9,200 KWh/year, while customers with primary electric space and water heating systems use approximately 15,728 KWh/year, with a net difference of over 6,500/KWh per year.[17]

15. Space heating load has a significant seasonal aspect – it occurs primarily during the winter system peak – thus contributing disproportionately to BC Hydro's capacity

[15] Exhibit B-10, at 24.

[16] Exhibit B-10, at 24. "It is easier to ramp DSM down than up. Ramping DSM down involves cancelling DSM programs or restricting eligibility criteria, which BC Hydro can do on its own; whereas ramping DSM up requires trade ally cooperation and action, which can be difficult or slow to secure."

[17] Exhibit C13-7, at 20.

requirements.[18] This is illustrated by the graph from the 2007 BC Hydro Rate Design Application that has come to be known as the "Terasen Graph."[19] The "Terasen Graph" depicts BC Hydro as having a pronounced winter system peak in the months of November through February, with residential space heating load being the single greatest contributor to the winter system peak while all the other rate classes' loads are relatively flat.[20] Adding new electric space heating load will, all else equal, result in an increase in the system peak.[21] The peak will, in fact, become more pronounced. Exhibit B-73, filed after the close of the oral hearing, demonstrates that approximately 64% of incremental space heating load will fall in the months of November, December, January and February. Eighty-five percent of the incremental space heating load is encompassed if the six-month period of October to March is considered. Exhibit B-73 further indicates that approximately 55% of the incremental space heating load would be expected to fall in the Peak or Super-Peak periods.[22] The potential for new space and water heating load to make BC Hydro's system peak more pronounced was also illustrated in the hypothetical scenario where all residential space heating load migrates from other fuels to electricity by 2020, with more than half of the incremental 22,000 GWh/year occurring during Super-Peak or Peak periods.[23]

(ii) Potential Sources of New Space and Water Heating Load

16. There are two potential sources of new space and water heating load. First, new BC Hydro customers or developers may choose to install electric appliances. Second, existing BC Hydro customers who currently use another energy source for space and water heating may convert to electricity as their appliances reach end of life.

[18] Exhibit B-73; Exhibit C13-7, at 11.

[19] Exhibit C13-7, at 11; see also Exhibit B-10, at 7, where BC Hydro stated that in mid-December 2008, its domestic system peak demand reached approximately 10,000 MW.

[20] Exhibit C13-7, at 18; Transcript, Vol. 6, at 877-878.

[21] Transcript, Vol. 6, at 878.

[22] Exhibit C13-7, at 43. The Peak and Super-Peak periods are the periods of high demand within the day when higher prices will be paid for supply based on Time-of-Delivery Factors in BC Hydro's Clean Power Call. The Time-of-Delivery Factors for electricity supplied in the Peak and Super-Peak periods are the highest in the winter months when most space heating occurs.

[23] Exhibit B-12, Response to Terasen IR 3.7.2 and Exhibit C13-7, at 43. The Terasen Utilities are citing this evidence to illustrate the seasonal nature of the load, not to suggest that this unlikely scenario will materialize.

Space and Water Heating Capture Rate (New BC Hydro Customers)

17. BC Hydro's load forecast assumes that, as new customers are added to the BC Hydro system, approximately 20% of new customers will install space heating and approximately 35% of new customers will install water heating, increasing to 21% and 38% respectively by the end of the 20 year forecast horizon.[24] These percentages of new customers that adopt particular end uses are referred to as "capture rates". BC Hydro's capture rates for space and water heating are extrapolated from BC Hydro billing data and reflect the current percentage of existing BC Hydro customers that have electric space heating and electric water heating (20% and 35% respectively).[25] The forecasted capture rates translate into over 5,500 new electric space heating customers per year over the forecast period and more than 8,600 new electric water heating customers per year.[26] The load associated with these additions compounds each year, and represents 12.8% of the forecast load growth between F2008 and F2027.[27] Looking at F2027 as a point in time the cumulative incremental annual space and water heating load attributable to customers captured between F2008 and F2027 is 1,933 GWh in F2027[28]. Of the 1,933 GWh, 1,409 GWh is for primary residential space heating, 483 GWh is for water heating and 41 GWh is for secondary space heating.[29]

18. BC Hydro's witnesses downplayed the importance to the overall load-resource gap of load associated with the capture of new space and water heating customers. Mr. Matheson implied, for example, that reducing the capture rate was of greater interest to the Terasen Utilities as natural gas utilities.[30] This view is at odds with BC Hydro's noted concern about the growing load-resource gap. The longer term nature of the investment made by customers in

[24] Exhibit B-10, at 11-12.

[25] Exhibit B-10, at 11; see also Exhibit C13-7, at 30; Transcript, Vol. 6, at 887. BC Hydro agreed that the increase in the capture rate for space and water heating will be higher than 1% and 3% over the 20 year planning horizon because the 21% and 38% reflect the percentage of total residential stock in 2028.

[26] Exhibit B-4, Response to Terasen IR 2.5.4.

[27] Exhibit C13-8; Transcript, Vol. 6, at 881-882. BC Hydro accepted that all numbers contained in the Witness Aid were correct.

[28] The 1,933 GWh of incremental annual space and water heating load is also 25.8% of the forecast gap in F2027 between the Mid-Load Forecast after DSM and Existing and Committed Supply or 10.1% of the forecast gap in F2027 between the Mid-Load Forecast before DSM and Existing and Committed Supply (Exhibit B-10, Table 2-10).

[29] Exhibit C13-8.

[30] Transcript, Vol. 11, at 2039.

appliances means that there is a higher probability that the load will be avoided if another energy source is adopted upon installation as compared to encouraging the customer with DSM incentives to reduce his electricity consumption associated with the installed electric appliance. Moreover, BC Hydro intends to take measures to address lesser contributors to the forecasted load. For instance, the impact of space heating load during the 20 year forecast period is greater than the additional load being addressed by the proposed FNU3.[31] It represents close to the same amount of energy as the post-attrition Clean Call of 2,100 GWh.[32]

19. The evidence suggests that 1,933 GWh in F2027 may understate the amount of load contributed by residential space and water heating over the planning horizon. The capture rates of 20% and 35%, from which the above figure is calculated, are an extrapolation from billing data. BC Hydro is not confident that its billing data is accurate.[33] BC Hydro's 2006 Residential End Use Survey ("REUS") suggested that the percentage of existing BC Hydro customers that have electric space heating is in excess of 30%, not 20%.[34] The amount added annually for electric space heating based on a 20% capture rate is about 74 GWh.[35] A 50% increase in the electric space heating capture rate (up from 20% to 30%) would therefore add approximately a further 37 GWh/year. [Although Mr. Matheson suggested that increasing the capture rate by 50% (from 20% to 30%) would only increase the load by about 9 GWh/year[36], mathematically this cannot be the case. Mr. Matheson appears to have incorrectly performed his calculation based on a 10% increase rather than a 50% increase and BC Hydro accordingly uses a figure of 10% in its Submission.] The 50% increase in space heating capture would represent

[31] Exhibit B-10, at 5, shows the change over 20 years in Fort Nelson as close to 800GWh, or less than half the amount attributable to new space heating alone.

[32] Transcript, Vol. 12, at 2208, lines 10-13.

[33] Exhibit C13-7, at 23; Transcript, Vol. 6, at 889-890.

[34] Exhibit C13-7, at 35-36; Transcript, Vol. 6, at 893-894.

[35] Exhibit B-4, Terasen Utilities IR 2.5.1 (attached to the witness aid filed in Exhibit C13-8) and Terasen Utilities IR 2.5.4. The annual load increase of approximately 74 GWh/year attributable to new primary space heating customers can also be confirmed from the response to Terasen IR 2.5.4. For example, multiplying the new electric space heating customers for F2010 of 5,517 customer by the annual space heating load per new account of 13,412 kWh/customer = 74 GWh. The average annual load per new account in Table B of Terasen IR 2.5.4 was confirmed in the BC Hydro 2007 Rate Design hearing as being solely attributable to space and water heating.

[36] Transcript, Vol. 11, at 2003. BC Hydro cited this evidence on page 61 of its Submissions.

additional annual load of approximately 705 GWh by F2027 (i.e., 50% of the 1409 GWh attributable to growth in primary electric space heating in F2027).[37]

Existing BC Hydro Customers Adopting Electric Space and Water Heating

20. In F2006, BC Hydro's residential customers consumed about 16,100 GWh[38], with space heating alone accounting for about 24% of that consumption.[39] That level of consumption is based on only a minority of BC Hydro's residential customers (20%-30%) having electric space heating. BC Hydro's load forecast, and the 12.8% or 1,933 GWh in F2027 cited above, assumes that none of the 70%-80%[40] of BC Hydro customers that currently have space heating appliances operated using another energy source will convert to an electric appliance during the next 20 years.[41] Given the age of the housing stock in BC, there are going to be households and businesses with gas heating systems that have reached end of life and require replacement. Some of these customers will convert to electric space and water heating if they continue to receive price signals based primarily on embedded costs, thereby further increasing the energy load and BC Hydro's supply requirements.[42]

(iii) Importance of Encouraging Efficient Choices among Energy Sources

21. Avoiding even a portion of the load associated with potential *new* customer captures of electric space and water heating will make a material contribution to closing the load-resource gap. Avoiding the potential for some of the 80% of *existing* customers to install electric appliances when their current non-electric appliances reach end-of-life will reduce the potential for exceeding the current load forecast. When other end uses for which energy source alternatives exist are included in the analysis, Electric Load Avoidance DSM takes on considerably more importance as a tool for BC Hydro to close the growing load-resource gap. Price signals that more closely reflect BC Hydro's marginal supply cost leave the customer free to make efficient choices for their particular circumstances.

[37] Exhibit C13-8

[38] Exhibit B-4, Response to BCSEA IR 2.28.1, Attachment 1, at 51.

[39] *Ibid*, at 52. Space heating share is much higher in electrically heated homes.

[40] The percentage of these customers depends on whether one uses 20% or 30% as the percentage of existing BC Hydro customers with electric space heating, per the billing data and REUS respectively.

[41] Transcript, Vol. 6, at 884-885.

[42] Transcript, Vol. 9, at 1483, where BC Hydro's witness agreed that BC Hydro's flat rates based on the embedded costs of supply were inadequate to encourage the efficient use of electricity.

III. THE ROLE OF ELECTRIC LOAD AVOIDANCE DSM IN SENDING EFFICIENT PRICE SIGNALS

22. Electric Load Avoidance DSM involves providing cost-effective incentive payments to customers faced with a decision to install appliances to encourage the customer not to adopt electricity for end uses where electricity is not the most efficient energy source from a TRC perspective. The incentive payments mitigate the potential for the customer to choose an energy source based on (i) the prospect of paying electricity rates based to a significant extent on BC Hydro's embedded cost of supply, or (ii) any differential in capital cost between electric appliances and appliances using another energy source.[43] Structuring Electric Load Avoidance DSM programs is a matter for future work; but, incentives can be based, for instance, on energy saved, square footage (for space heating), volume (for water heating), or the incremental capital cost of adopting an alternative energy source.[44] Electric Load Avoidance DSM encourages the customer not to adopt electricity, but is neutral in that it leaves the customer free to make the choice as to the appropriate energy source for a particular application based on a more efficient price signal. The right energy source for a particular customer, for a particular application, in the customer's particular circumstances might be electricity, natural gas, or some other energy source.[45]

23. BC Hydro customers pay rates primarily reflecting embedded costs, and are insulated from BC Hydro's true marginal cost of supply. The BC Hydro RIB rate improves the conservation price signals experienced by residential customers; however, there is still room for improved conservation signals as, by its design, many customers see mainly the Step 1 rate. The Step 2 rate changes lag behind BC Hydro's marginal cost of supply. BCUC Order No. G-124-08 and the RIB Decision set the residential Step-2 rate at 8.27 cents per kWh (equal to $82.70 per

[43] Transcript, Vol. 9, at 1509.

[44] BC Hydro has used similar approaches in the context of its load reduction DSM in the LTAP. See B-1, Appendix K, Sub-Appendix F, Program Summaries.

[45] BC Hydro discounted the potential for other fuel source alternatives to gain a foothold. See, e.g., Transcript Vol. 11, at 1999-2000 where BC Hydro's witness stated that "[w]e're certainly see a lot of additional interest in heat pumps currently, but I think they still represent a fairly small -- a small percentage, and I think there's some uncertainty in terms of how it's going to unfold moving forward". However, it is also necessary to consider the fact that this may reflect the current inefficient pricing of electricity from a TRC perspective as a competing energy source.

MWh) effective April 1, 2009.[46] This is well below the expected marginal supply cost identified in the LTAP proceeding of $120 per MWh. For those customers who mainly see the Step 1-rate, it is below the previous flat rate because it is set residually.

24. Relative differences in the capital cost associated with adopting a particular energy source can also represent an impediment to efficient choices regarding energy source. To illustrate, a customer faced with installing a new heating appliance might currently be expected to choose electric space heating in the absence of the right pricing signals or incentives,[47] as an electric plenum or baseboard heaters may appear to the customer to be cheaper than adopting a higher efficiency natural gas furnace, or adopting another type of technology such as heat pumps or geo-exchange systems.

25. It is important to send the appropriate price signals and messaging to customers and developers at the time the choice of energy source is made, because once the choice is made and the customer has invested in appliances it represents an obstacle to later changing to a different energy source. As BC Hydro agreed, a new house "built without ductwork and with baseboard heating... [has] an obstacle for inputting either a natural gas furnace or a heating [sic] pump in the future."[48] BC Hydro's Submissions expanded on this point:

> A customer's choice at the moment of installing space and water heating is a long term selection. Once made, it is difficult (expensive) to reverse. The appliances have useful lives of approximately 20 years and the building structures, and internal infrastructure would be much longer. Such choices are not minute to minute or day to day or year to year decisions. They are relatively permanent and have short, medium and long-term consequences.

Although BC Hydro was intending by the above submission to urge caution in pursuing Electric Load Avoidance DSM, the passage speaks much more strongly to the Terasen Utilities' point

[46] The Commission's Decision in the RIB Application included it its design principles parameters as to when BC Hydro must come forward with a proposal to change its cost of new supply and how to phase in the change. See for instance, In re BC Hydro, Residential Inclining Block Rate Application, Reasons for Decision (September 24, 2008), at 108.

[47] Transcript, Vol. 9, at 1503-1505; see also Transcript, Vol. 11, at 2000-2001

[48] Transcript, Vol. 11, at 2001. When responding to the question of whether a new house built without ductwork and with baseboard heating would have "an obstacle for inputting either a natural gas furnace or a heating pump in the future," Mr. Hobson stated that "Depending on the type of home it is, it'll create some limitations, yes."

that these customers who are faced with a decision as to appliances using different energy sources should be the primary targets of Electric Load Avoidance DSM.

26. BC Hydro should pursue cost-effective Electric Load Avoidance DSM in tandem with its proposed portfolio of load reduction DSM. It is not in the best interest of customers for BC Hydro to wait passively for customers to adopt electrical appliances where it does not make sense from a TRC perspective, in full anticipation of spending *load reduction* DSM dollars to avoid high marginal supply costs associated with serving that added load. Load reduction and load avoidance have the same value to BC Hydro customers in terms of BC Hydro avoiding new high cost supply; however, successful load avoidance provides additional certainty that new supply will not be required over the long useful life of the adopted non-electric appliances.[49] As discussed later in these Submissions, BC Hydro and the Terasen Utilities agree that the installation of a particular type of appliance is a barrier to changing energy source during the life of the appliance. BC Hydro can target its load reduction DSM dollars to customers who have chosen electricity as an energy source based on more efficient price signals from a utility resource cost (i.e. TRC) perspective. Puget Sound Energy and Avista are examples of other utilities that use incentive programs to address the fact that their rates structures would otherwise tend to encourage adoption of electricity where more efficient fuel choices are available.[50]

IV. BENEFIT TO BC HYDRO CUSTOMERS ASSOCIATED WITH ELECTRIC LOAD AVOIDANCE DSM

27. Government has indicated its objective is "to encourage public utilities to pursue demand-side measures", and the UCA requires BC Hydro to provide an explanation in the LTAP as to why cost-effective DSM is not being pursued.[51] The Commission's overarching responsibility is to ensure that rates are just and reasonable.[52] In light of these requirements, the starting place for the Commission's analysis of Electric Load Avoidance DSM must be its

[49] Transcript, Vol. 11, at 1996-1997.

[50] Transcript, Vol. 9, at 1518. Puget Sound Energy offers one-time incentives to eligible customers to help defray the cost of conversion to highly efficient natural gas space heating and/or domestic water heating. The incentive program is structured as a rebate to customers based on type of existing electric heating to be replaced and the amount of historic energy usage (see Exhibit C13-9, at 6). Avista offers similar home improvement incentives for space heating conversion from electric to natural gas or air/ground source heat pump (see Exhibit C13-9, at 17).

[51] UCA, s. 44.1(2) (b), (f).

[52] UCA, ss. 59 - 61.

impact on the rates paid by BC Hydro customers.[53] This Part of the submissions address the following points:

(i) The legislative scheme in the UCA requiring public utilities to look first to cost-effective demand-side measures is realized by BC Hydro pursuing Electric Load Avoidance DSM identified as having a TRC ratio of benefits to costs of more than one.

(ii) The 2007 CPR identified significant *economic potential* (determined on a TRC basis) for Electric Load Avoidance DSM. From an overall resource cost (i.e. TRC) perspective, BC Hydro customers collectively stand to benefit from the pursuit of this *economic potential*.

(iii) The *economic potential* for Electric Load Avoidance DSM will likely be higher today than in the 2007 CPR based on a much higher avoided cost of new electricity supply.

(iv) In light of the cost implications for all BC Hydro customers, Electric Load Avoidance DSM exhibiting a favourable TRC should not be eliminated from contention by means of a simple payback analysis based on current rates paid by customers that reflect, to a significant extent, embedded costs.

A. Cost-Effectiveness Determined By TRC Analysis

28. The cost-effectiveness of Electric Load Avoidance DSM is determined with reference to a TRC analysis, which focuses on the resource costs and benefits of electricity and a fuel alternative.

29. BC Hydro customers as a whole will benefit from BC Hydro making available the necessary cost-effective Electric Load Avoidance DSM to avoid load that would otherwise have to be served at BC Hydro's marginal cost of new supply. Electric Load Avoidance DSM with a TRC of more than one (identified in BC Hydro's CPR as having *economic potential*) that is not pursued represents a lost opportunity to manage resource costs for the benefit of all BC Hydro customers. BC Hydro rates will experience greater upward pressure than would be the case (all

[53] BC Hydro stated in its Submissions at 19 line 18 to 11 that "it is the interests of its existing and future customers that are paramount, especially when compared to, say, another intervening utility, which has obvious commercial interests." The Terasen Utilities agree that the Commission should base its findings regarding Electric Load Avoidance DSM on the interests of BC Hydro's customers. The evidence is that Electric Load Avoidance DSM is in the interests of BC Hydro customers. Whether or not the commercial interests of the Terasen Utilities are aligned with the interests of BC Hydro customers is irrelevant.

else equal) if the targeted load is reduced or avoided by the adoption of other alternative energy sources including natural gas.[54]

30. Using the TRC test to assess the cost-effectiveness of Electric Load Avoidance DSM is consistent with the DSM Regulation. The Regulation references TRC as a measure to determine cost-effectiveness in respect of particular DSM programs and requires the Commission to use BC Hydro's avoided cost of supply for assessing the cost-effectiveness of measures taken by entities that receive service from BC Hydro.[55] In the Commission's recent decision on TGI and TGVI's Energy Efficiency and Conservation ("EEC") Application, the Commission endorsed the use of the TRC test more generally.[56]

B. Economic Potential Identified in 2007 CPR

31. The section of the CPR addressing Electric Load Avoidance DSM considered only natural gas as a fuel alternative to electricity for particular end uses, and referred to the measures examined as "fuel switching" measures. Opportunities clearly exist for BC Hydro to explore Electric Load Avoidance DSM involving other alternative energy sources apart from natural gas, and it would be appropriate for all energy source alternatives to be considered in future analysis of Electric Load Avoidance DSM.

32. The CPR identified whether measures had *economic potential*, defined by a TRC of greater than one.[57] Notably, the CPR equated this *economic potential* with "cost-effective" Electric Load Avoidance DSM,[58] which is appropriate. In the context of the Electric Load

[54] Transcript, Vol. 9, at 1523.

[55] For instance, the DSM Regulation provides for the use of TRC for the low-income programs. Section 4(2) allows the use of avoided cost, rather than the purchase price, as the measure for benefit, when assessing cost effective of a DSM of a bulk electricity purchaser. Additionally, section 4(4) specifies that the Commission cannot reject DSM based on a ratepayer impact measure test.

[56] In Re Terasen Gas Inc. and Terasen (Vancouver Island) Inc., Energy Efficiency And Conservation Application, Decision (April 16, 2009) ("EEC Decision"), at 34: "The Commission Panel also takes note of the DSM Regulation which will apply to Terasen as of June 01, 2009 requiring the Commission to use, in addition to any other test it considers appropriate, the TRC test in determining whether a demand-side measure is cost-effective. While the DSM Regulation is not in effect for the purposes of this Decision, the Commission Panel does consider the TRC test to be appropriate and adequate for the purposes of this Application and accepts it as such."

[57] Exhibit B-1-1, Appendix K, CPR Summary Report, at 15; see also Exhibit B-4, Response to BCUC IR 2.201.5, 2.206.1.

[58] Exhibit B-4, Response to BCSEA IR 2.28.1, Attachment 1, at 109. The CPR states "[i]n this study, 'cost-effective' means that the fuel-switching measure passes the Measure Total Resource Cost (TRC) test."

Avoidance DSM examined in the CPR, the TRC analysis considered the resource costs of both electricity and the alternative energy source (natural gas, in this case). TRC was defined in the CPR as "the net present value of energy savings that result from an investment in a fuel-switching measure." It is equal to "its full or incremental capital cost (depending on application) plus any change (positive or negative) in the combined annual energy and operating costs."[59] The CPR used BC Hydro's avoided cost of electricity ($88/MWh based on the results of the F2006 Open Call for Power[60]) to determine any applicable changes in operation costs.[61] In simple terms, the measures identified as having *economic potential*, i.e. a TRC Benefit/Cost ratio of greater than one, have the potential to provide a net benefit to BC Hydro customers as a whole based on BC Hydro's avoided supply costs.

33. The CPR identified significant *economic potential* for Electric Load Avoidance DSM that uses natural gas as an alternative fuel in the residential, commercial and industrial sectors.[62] The *economic potential* of Electric Load Avoidance DSM in the BC Hydro CPR was found to be 24.02 PJ equivalent (6,674 GWh/year) by 2026 in the current gas supply cost scenario, and 11.85 PJ equivalent (3,293 GWh/year) by 2026 in the high gas supply cost scenario.[63] BC Hydro's 2007 CPR concluded that

> [u]nder the Current supply cost forecast, there are a number of fuel-switching measures . . . that have a positive Measure TRC [i.e. TRC for the measure expressed in dollars is positive] and a Measure Benefit/Cost ratio that is equal to, or greater than one. This result suggests that from a provincial economic perspective, there are opportunities where switching from electricity to natural gas may be beneficial.[64]

C. Increase in BC Hydro's Avoided Cost of Supply Increases Economic Potential

34. BC Hydro's avoided cost of supply is a key input in the determination of *economic potential*, and the avoided cost of supply has increased markedly since the 2007 CPR

[59] Exhibit B-4, Response to BCSEA IR 2.28.1, Attachment 1, at 21.

[60] Exhibit B-1-1, Appendix K, Summary Report, at 15.

[61] Exhibit B-1-1, Appendix K, Summary Report, at 53.

[62] Exhibit B-1, Response to BCSEA IR 2.28.1, Attachment 1 at 6.

[63] Exhibit B-4, Response to BCSEA IR 2.28.1, Attachment 1, at 111 (current natural gas supply cost scenario); at 115 (high natural gas supply cost scenario).

[64] Exhibit B-4, Response to BCSEA IR 2.28.1, Attachment 1, at 108.

was conducted.[65] All else equal, the *economic potential* increases with the increases to BC Hydro's avoided cost of supply.

35. The *economic potential* in the 2007 CPR was identified using an avoided cost of supply of $88/MWh, based on an average of the results of the F2006 Open Call for Power.[66] BC Hydro's Evidentiary Update identified an avoided supply cost of $120/MWh (F2006 dollars) for the purposes of assessing DSM portfolios.[67] This represents a proxy for the expected average bid price in the current Clean Power Call.[68] The $120/MWh avoided cost of supply does not include distribution costs or line losses for distribution,[69] which would also be incurred when delivering non-avoided electricity to end use customers. The distribution line losses alone add an additional four percent to the delivered cost of energy.[70]

36. The $120/MWh avoided supply cost also does not account for the fact that space heating load occurs in winter months when electricity is the most expensive.[71] As an example, a single customer with 4,260 kWh of space heating load would consume more than over 3,000 MWh from November to March.[72] The cost of serving space heating load, even before factoring in line losses, is likely closer to $130/MWh[73] using the most recent weighted average time of delivery percentage of 108% provided by BC Hydro.[74]

[65] Transcript, Vol. 9, at 1522.

[66] Exhibit B-1-1, Appendix K, CPR Summary Report, at 15. Exhibit C13-12 and Transcript 11, at 2020-2021 evidence the Terasen Utilities' objections to the CPR. In calculating the TRC of electricity-to-gas "fuel switching" measures, BC Hydro used both a current and high gas forecast. However, it only employed the current forecast on the electricity side, which was then $88/MWh. The result of considering a high gas cost scenario without accounting for upward pressure in marginal electricity supply costs was to reduce the amount of economic potential. The Terasen Utilities registered its objections to this approach during the stakeholder process in the CPR.

[67] Exhibit B-10, at 25; Transcript, Vol. 9, at 1528.

[68] Transcript, Vol. 9, at 1522.

[69] Transcript, Vol. 9, at 1529-1530

[70] Exhibit B-12, Response to Terasen IR 3.7.1.

[71] See Transcript, Vol. 6, at 915-918, for an explanation of the correlation between peak months and energy prices.

[72] Exhibit B-73, BC Hydro Undertaking No. 10.

[73] $120/GWh x 1.08 = $129.6/GWh

[74] Exhibit B-73, BC Hydro Undertaking No. 10. The undertaking response filed by BC Hydro as Exhibit B-73 was based on the time of delivery pricing from the 2009 Call for Tenders webpage. (Exhibit C13-7, at 43). The undertaking response corrected an error in BC Hydro's response to Terasen Utilities IR 3.7.3 (Exhibit C13-7, at 42), in which BC Hydro had accounted for the consumption of electric space heating customers for all end uses rather than just space heating. See also Transcript, Vol. 6, at 913.

37. Natural gas cost is a component of the TRC analysis for Electric Load Avoidance DSM examined within the CPR. The Terasen Gas combined commodity cost and midstream charge based on service to the Lower Mainland was $8.551 per GJ at the time of the hearing, well within the scenarios examined in the CPR, and within the BC Hydro long-term natural gas price forecast.[75] The carbon tax would have to be added to this value, but as $8.551 per GJ is less than one third the cost of BC Hydro's avoided cost of supply there is a significant margin to allow for this and yet still yield a favourable TRC. $120/MWh corresponds to an equivalent gas cost of $30.00 per GJ.[76]

38. The significant increase in the avoided cost of new electricity supply from the $88/MWh used in the 2007 CPR, combined with the fact that the current gas cost forecast remains within the scenarios employed in the 2007 CPR, indicates growing opportunities for BC Hydro to address a portion of the load-resource gap with cost-effective Electric Load Avoidance DSM.

D. Customer Payback Calculated Based on Embedded Cost Rates

39. The CPR did not identify any *achievable potential* for the Electric Load Avoidance DSM considered[77] because customers paying rates that reflect the low embedded cost of electricity do not see the "payback" necessary from these measures to consider adopting another energy source.[78] The Terasen Utilities, which were involved in the CPR stakeholder process, have consistently expressed concerns about eliminating measures based on payback established with reference to rates based to a significant extent on embedded costs.[79] The embedded cost of electricity does not produce effective price signals for conservation, a fact

[75] Exhibit B-1, at 4-16, Figure 4-2.

[76] Exhibit C13-11; Exhibit B-33.

[77] Exhibit B-4, Response to BCSEA IR 2.28.1, Attachment 1, at 108 and footnote 65..

[78] Exhibit B-1-1, Appendix K, BC Hydro CPR 2007, Summary Report, at 55. The simple payback, according to the CPR, is "a measure of the length of time required for cumulative savings from a project to recover its initial investment cost and other secured costs, without taking into account of the time value of money." Exhibit B-4, Response to BCSEA IR 2.28.1, Attachment 1,at 21-22. See also Exhibit C13-5, at 38, where the excerpt from the CPR states: "This somewhat contradictory result (i.e. measure passes the economic screen but has excessively long payback period) is explained by the large discrepancy between the wholesale and retail prices for natural gas and electricity."

[79] Exhibit C13-12, at 23; Transcript, Vol. 11, at 2020-2021.

which BC Hydro recognized in adopting the RIB rate structure.[80] BC Hydro has a responsibility to its customers to identify incentive models to turn the identified *economic potential* into *achievable potential.*

E. Summary

40. A proactive approach by BC Hydro to developing appropriate Electric Load Avoidance DSM incentives will help to ensure that customer choices are not made based on inefficient price signals to the detriment of customers as a whole. The significant increase in the avoided cost of supply from the $88/MWh used in the 2007 CPR provides greater opportunities for BC Hydro to use Electric Load Avoidance DSM to address a portion of the load-resource gap.

V. REGIONAL REDUCTION IN GREENHOUSE GAS EMISSIONS

41. BC Hydro's objection to Electric Load Avoidance DSM is rooted in the assumption that natural gas is the logical alternative energy source for particular end uses, discounting the potential for British Columbians to adopt other alternative energy sources that have the potential to attract a larger market share with efficient pricing of electricity. The Terasen Utilities agree that natural gas can provide appropriate energy solutions and could be the right choice for some customers. However, the potential for natural gas consumption in direct use applications within BC to reduce GHG emissions on a regional basis, combined with the obligation on British Columbians to pay the carbon tax on domestic natural gas consumption, eliminates BC Hydro's primary policy basis for opposing natural gas as part of Electric Load Avoidance DSM. In this part we make the following points.

(i) There are three equally compelling reasons why Electric Load Avoidance DSM involving natural gas can, on a regional basis, "reduce greenhouse gas emissions" as contemplated in "government's energy objectives". They are:

(A) First, the use of natural gas or alternatives for specific end uses in British Columbia will make additional hydroelectricity available

[80] In re BC Hydro, Residential Inclining Block Rate Application, Reasons for Decision (September 24, 2008), at 50, 95, 107. Dr. Orans also noted in the RIB Application proceedings that to assess the RIB as a mechanism to encourage conservation, BC Hydro "should be probably looking at a total resource cost perspective and looking at the choices customers have and the choices that BC Hydro has for meeting a new supply." (Exhibit C13-9, at 3). BC Hydro should similarly be approaching Electric Load Avoidance DSM from a TRC perspective.

for export to displace coal or gas-fired generation on the margin in the Western Interconnection.

(B) Second, Electric Load Avoidance DSM reduces the need for BC Hydro to import electricity that is frequently generated through the relatively inefficient consumption of gas or coal.

(C) Third, natural gas will be consumed at a higher efficiency, with a lower emission factor, in end-use appliances than if it is exported for use in generating electricity.

(ii) Efficient pricing of natural gas is achieved in part by requiring domestic consumers to pay the carbon tax or (in BC Hydro's case after 2016) acquiring offsets. The focus in this proceeding should be on achieving the right pricing for electricity, which will permit energy consumers to arrive at the optimal balance among alternative energy sources.

42. Electric Load Avoidance DSM represents a means of reducing (all else equal) electricity rates for all customers while remaining aligned with government's interest in mitigating climate change through the right pricing of energy sources.

A. Electricity Exports Displace Coal and Gas Fired Generation on the Margin

43. The Commission has concluded twice previously that exporting surplus electricity achieved by using a more efficient resource alternative in British Columbia will displace coal or gas-fired generation at the margin in the Western Interconnection. The evidence in this proceeding continues to support those determinations.

(i) Previous Commission Decisions

44. In the Commission's October 26, 2007 Decision on BC Hydro's 2007 Rate Design – Phase 1, the Commission stated:

> Commission Panel commends Terasen for its initiative in leading evidence both concerning the use of electricity for space and water heating in BC Hydro's service area, and concerning the potential growth in demand for electric space and water heat that BC Hydro is forecasting. The implications of the growth in demand were among the reasons that led the Commission Panel to encourage and guide BC Hydro to implement an inclining block residential rate, so that customers receive the correct pricing signal in this regard. <u>The Commission Panel agrees with Terasen that the use of natural gas (as opposed to electricity) for space</u>

> and water heating in B.C. will make additional energy available to displace coal or gas-fired generation at the margin in the Pacific Northwest [Emphasis added].[81]

45. The Commission repeated in December 2007 that it "continues to agree with Terasen that the use of natural gas (as opposed to electricity) for space and water heating in BC will make additional energy available to displace coal."[82]

46. In the Commission's recent decision on the Terasen Utilities' EEC Application, the Commission found "that the 'optimal balance' as between natural gas and electricity has not been established" on the evidentiary record in that Application and "that the efficiency of other energy sources over and above that of electricity has not been adequately established."[83] The EEC Panel determined that there was insufficient evidence on the record to conclude that "a regional approach should be adopted as a justification for EEC expenditures aimed at substituting natural gas as a fuel to replace electricity."[84] The evidentiary record in this proceeding, unlike the EEC Application, contains voluminous evidence with respect to the relative efficiency of electricity and gas, and the benefit to BC Hydro customers associated with Electric Load Avoidance DSM. BC Hydro's CPR considered, in a TRC analysis, the benefits and costs of particular measures in light of the resource costs of both electricity and the alternative energy source.[85] The *economic potential* for particular Electric Load Avoidance DSM is quantified, and the positive impact on BC Hydro customers in the form of reduced rates (all else equal) is clear. The CPR concluded that "This result suggests that from a provincial economic perspective, there are opportunities where switching from electricity to natural gas may be beneficial."[86] The measures envisioned in the CPR do not require any determination to be made, either by BC Hydro or the Commission as to the "optimal balance" among energy sources. Rather, by putting in place appropriate price signals, British Columbians will make appropriate choices based on their own requirements. The evidence in this proceeding as to BC Hydro's

[81] In re British Columbia Hydro and Power Authority 2007 Rate Design Application – Phase 1, Decision (October 26, 2007), at 191.

[82] In re Terasen Gas (Vancouver Island) Inc. and Terasen Gas Inc., System Extension And Customer Connection Policies Review, Decisions (December 6, 2007), at 50.

[83] EEC Decision, at.17.

[84] EEC Decision, at18.

[85] See, e.g., Exhibit B-4, Response to BCSEA IR 2.28.1, Attachment 1, at 90-108.

[86] Exhibit B-4, Response to BCSEA IR 2.28.1, Attachment 1, at 108.

approach to purchasing offsets outside BC in order to reduce the cost of those offsets for BC Hydro customers (discussed below) also supports the regional approach to considering GHGs.

(ii) Evidence in this Proceeding

47. The evidence in this proceeding supporting the conclusion that the use of an alternative energy choice for applications such as space and water heating in BC will make additional energy available to displace gas and coal-fired generation is summarized below. The evidence comes from documents on the record, BC Hydro's written evidence (i.e. Application and IR responses), and the cross-examination of BC Hydro witnesses. As such, it was unnecessary for the Terasen Utilities to call evidence in this regard.

48. Renewable power generated in British Columbia that is surplus to the domestic load requirements in any one time period will be exported into the Western Interconnection.[87] In the vast majority of the time (over 80%), the marginal source of electricity supply in the Western Interconnection is generated from natural gas-fired or coal-fired generation facilities.[88] During such times, the injection of BC renewable power in to the Western Interconnection will displace existing or new gas or coal-fired generation.[89] As the Global Energy report included with the LTAP stated, "the renewables will run to meet the load, thereby displacing natural gas-fired generation that would otherwise be needed to meet loads…. In the cases with high penetrations of renewables, economic dispatch would sometimes displace coal-fired generation rather than natural gas-fired generation….".[90]

49. The pursuit of cost-effective Electric Load Avoidance DSM will result in reduced electric load in BC. The Terasen Utilities submit that this also logically will lead to BC

[87] Exhibit B-3, Response to Terasen IR 1.2.2, 1.2.6.

[88] Exhibit B-3, Response to Terasen IR 1.2.6.. When asked whether in the Western Interconnection, either natural gas-fired or coal-fired generation would be on the margin more than eighty percent of the time, BC Hydro responded that this is "generally" true. (See Exhibit B-4, Response to Terasen IR 2.4.2).

[89] Exhibit B-3, Response to Terasen IR 1.2.6; see also Transcript, Vol. 3, at 271-272.

[90] Exhibit B-1-1, Appendix H, at 11-12. In Exhibit B-3, Response to Terasen IR 1.2.6, BC essentially confirmed the cited statement by stating "adding any resource into the WECC grid, be it renewable or non-renewable, will displace the marginal unit if the resource that is being added has a lower variable operating cost than the marginal unit." As described later in these submissions, this same displacement occurs with natural gas produced in British Columbia. The combined emissions factor associated with the production of BC natural gas and its consumption in either direct use applications or an efficient CCGT is well below the emissions factor attributed to BC Hydro's imports in 2006. Therefore, the use of BC's natural gas in the WECC region results in a GHG benefit. (Citations provided below.)

renewable power that would otherwise serve BC load being available for export (the evidence supporting this logic and BC Hydro's argument to the contrary is addressed below). These exports associated with Electric Load Avoidance DSM will reduce GHGs in the region even where BC Hydro customers have chosen natural gas as the alternative fuel because of the difference in combustion efficiency between domestic gas appliances and gas and coal-fired generation that is displaced by the clean power made available for export. Combustion efficiency is important in terms of lowering GHG emission.[91] A modern combined-cycle gas-fired generator (CCGT) operates at about 50% efficiency, and the efficiency rate of a coal-fired generator is even lower.[92] In contrast, modern domestic gas furnaces and hot water heaters operate at much higher efficiency – typically between 85 percent and 95 percent efficiency.[93] The emissions factor for furnaces is 200 tonnes / GWh[94], the emissions factor for a CCGT operating at 50% efficiency is 360 tonnes / GWh and BC Hydro's imports are assigned an emissions factor of 550 tonnes/ GWh.[95]

50. BC Hydro witnesses conceded that during the two-year LTAP period, if more customers choose direct use of natural gas for heating applications, particularly for spacing heating, there will be "more electricity available for export from British Columbia."[96] BC Hydro's evidence and its submissions regarding its own planning response to reduced load in the medium to long term[97] do not speak to the potential for IPPs to build in excess of BC Hydro's load requirements and export the surplus power. BC Hydro confirmed that it was not the only potential purchaser for renewable power generated in BC over the medium to long-term, and that

[91] Transcript, Vol. 12, at 2171-2173.

[92] Exhibit B-3, Response to Terasen IR 1.2.5.

[93] Transcript, Vol. 11, at 2039-2040. BC Hydro witnesses agreed that a modern space heater operated on natural gas is rated as generally between 85 and 95 percent efficiency. See also Exhibit C13-9, at 11, 14. According to Puget Sound, direct use of natural gas to fire a home furnace would make use of 80% of the original energy content of the gas as heat for the home. Avista is using a 90% efficiency rate.

[94] CPR, Exhibit B-4, BCSEA IR 2.28.1, Attachment 1, at page 121, notes that the GHG emission intensity factor for natural gas is 180 tonnes/GWh for direct use of natural gas. However, this appears to correspond to 100% efficiency. 90% efficiency, by our calculations, is closer to 200 tonnes per GWh, so we have used this amount in these Submissions.

[95] Exhibit B-4, BCSEA IR 2.28.1, Attachment 1, at.121. Also, it is clear that emissions levels in the WECC regional will remain at this level for some time, as estimated average performance standard in Alberta, Arizona, New Mexico, Montana, Utah, Colorado, Nevada, Idaho, and Wyoming. A performance standard is the GHG emissions level above which **offsets** must be acquired. (Exhibit B-1, at 4-20, lines 14-21).

[96] Transcript, Vol. 6, at 824.

[97] Exhibit B-4, Response to BCSEA IR 2.29.2.

neither law nor policy precludes IPPs from continuing to build for direct export.[98] The provincial government is contemplating an export market for BC power. Former Minister Richard Neufeld said in a CBC interview on the subject of IPP power: “We have huge opportunities in this province to build generation for export, also, between jurisdictions south of us that generate with coal.”[99] A transmission line from Canada to Northern California is currently under consideration to capitalize on such potential clean power export.[100] The Terms of Reference for the Commission’s pending Section 5 Inquiry similarly contemplate pursuing the Province’s potential for exporting clean, renewable energy.[101] The Terms of Reference also state that when making assessment of generation resource development, the Commission should consider that “other jurisdiction will continue to pursue the reduction of greenhouse gas emission…”.[102] The Climate Action Team recommended building for surplus for export.[103] Additional evidence regarding the demand for BC renewables is referenced by BC Hydro on pages 68 and 69 of its Submissions.

51. This same approach is evident in the decision of the Manitoba Public Utilities Board with respect to the effect of exporting clean power, which was referred to during the hearing.[104]

52. BC Hydro relies in its argument[105] upon Dr. Jaccard’s evidence regarding the need to move to electrification of space and water heating in order to make a significant impact in climate change. Dr. Jaccard’s analysis is premised on the very long-term horizon when there is no longer gas and coal-fired generation on the margin in the Western Interconnection that can be displaced by the high-efficiency direct consumption of natural gas in domestic and commercial applications in British Columbia. Jurisdictions within the Western Interconnection have made significant investments in gas and coal-fired generation (they account for 58% of the energy

98 Transcript, Vol. 3 at 297-298.

99 Exhibit C13-5, at 70; Transcript, Vol. 3, at 298-299.

100 Exhibit C13-5, at 68.

101 Terms of Reference (available at http://www.bcuc.com/sectionfiveinquiry.aspx). One of the recitals is: “Whereas the 2007 Speech from the Throne stated: Government will pursue British Columbia’s potential as a net exporter of clean, renewable energy.”

102 Terms of Reference, Section 6 (b) (vi).

103 BC Hydro Submissions, at 55. See Item 15.

104 Transcript, Vol.6, at 811 to 814.

105 BC Hydro Submissions, at 56.

generation),[106] and it will be decades before these are displaced by a cleaner domestic resource. Notably, California, Washington and Oregon have used a CCGT operating at 50% efficiency level as their performance standard for clean electricity.[107]

53. BC Hydro has made an unjustified leap in logic in assuming that exports from BC will only displace higher cost renewables. In the Western Interconnection, gas and coal-fired generation collectively represent about 58% of the energy generation, and are on the margin over 80% of the time.[108] Renewables currently represent approximately 6% of energy generation in the WECC.[109] Appendix H of the LTAP Application, Global Energy's Renewable Energy Market Analysis Report, contemplates that introducing renewable power into supply resources of the Western Interconnection will displace gas-fired and coal-fired generation. For instance, the Report states:

> Global Energy is also aware that the WCI is reviewing studies done by the California Energy Commission (CEC) that show amounts of GHG reductions in each Western state under different penetrations of energy efficiency and renewables.
>
> The CEC studies discussed in the above paragraph were performed by running hourly simulations of the WECC power grid, with hourly loads across WECC being served by economic dispatch of generation available in the region. In its "current conditions extended into the future" case, the CEC studies demonstrate the reality that much load in WECC is served by natural gas-fired generation. As the CEC increased penetration of renewables in the future in its alternative views of the future, the renewables will run to the meet the load, thereby displacing natural gas-fired generation that would otherwise be needed to meet loads. The CEC ran a few sensitivities with high GHG taxes in place. In the cases with high penetrations of renewables, economic dispatch would sometimes displace coal-fired generation rather than natural gas-fired generation because coal generation emits about twice the amount of GHG/kWh than does natural gas-fired generation. The CEC concludes that a good way to reduce GHG is to reduce thermal generation levels by causing higher penetrations of energy efficiency and renewable power supplies.[110]

[106] Exhibit B-3, Response to Terasen IR 1.2.3; 2.4.2.

[107] Exhibit B-1, at 4-20, lines 4-10. This means that GHGs are offset to the level of a 50% efficient CCGT only, which implicitly means that gas-fired generation will continue to play a role in the WECC region to displace coal-fired generation on the margin.

[108] Exhibit B-3, Response to Terasen IR 1.2.3; 2.4.2.

[109] Exhibit B-3, Response to Terasen IR 1.2.3

[110] Exhibit B-1-1 Appendix H, at 11 and 12.

54. Also, fulfilling RPS targets is not the only reason that parties from U.S. jurisdictions may seek to acquire green power from BC. Mr. Youngman noted, for instance, the potential for significant changes under the Obama Administration in the areas of cap and trade and more aggressive climate change policies and legislation.[111] This suggests that changes imposed at the U.S. federal level could begin to overtake the RPS requirements imposed at the state level. It is clear, however, that if BC's renewable electricity is consumed for space and water heating in BC, then it will not be available to reduce the heavy reliance on fossil fuel-based electricity generation in other jurisdictions.

55. Based on the evidence discussed above, the Commission should reject BC Hydro's argument on page 68 of its Submissions that the premise of regional impacts "can only be derived by two events simultaneously occurring: (1) BC Hydro having surplus it did not plan for as a result of fuel switching or BC Hydro building for export; and (2) No U.S. entity wanting to acquire BC Hydro's clean or renewable energy to fill that entity's RPS targets."

B. Avoidance of Imports of Electricity Generated from Coal and Natural Gas

56. BC Hydro is a net importer of electricity in most years.[112] More than 50% of BC Hydro's imports come from low-efficiency gas-fired and coal-fired generators elsewhere in the Western Interconnection.[113] BC Hydro's reliance on these imports would decrease as load requirements associated with, for instance, space and water heating decreased. According to BC Hydro's 2007 CPR, a GHG factor of 550 tonnes per GWh was assigned for BC Hydro's electricity generation based on actual values for imported electricity in F2006, whereas the Greenhouse Gas Emission Factor for a high efficiency furnace is 200 tonnes/GWh.[114] Thus, there is a clear GHG reduction advantage to using natural gas in direct end use applications to reduce BC Hydro's requirements to import electricity produced by gas or coal-fired generation. BC Hydro has acknowledged this environmental benefit in previous proceedings: "In the past

[111] Transcript, Vol.9, at 1583 to 1585.

[112] Transcript, Vol. 3, at 270; Transcript, Vol. 6, at 814.

[113] Transcript, Vol. 3, at 271; Exhibit C13-5, at 40.

[114] Exhibit B-4, Response to BCSEA IR 2.28.1, Attachment 1, at 121. As indicated in a later footnote, the 200 tonnes/GWh figure was derived from evidence that suggests natural gas at 100% efficiency produces 180 tonnes/GWh. The Terasen Utilities recalculated this based on 90% efficiency.

BC Hydro encouraged customers to use natural gas instead of electricity for space heating, based on economic <u>and environmental</u> considerations." [Emphasis added.][115]

57. Self-sufficiency is a "red herring" in this analysis. BC Hydro will remain a net importer until it achieves self-sufficiency,[116] but will continue to import power after 2016 as self-sufficiency is determined on an annual net basis.[117] From the perspective of GHG emissions, the relevant consideration is what resource is on the margin in the Western Interconnection at the time of the imports. Where imports occur during the peak winter months, space heating load can be expected to drive a disproportionate amount of the imports of electricity generated from the combustion of gas and coal.

C. Natural Gas is Consumed at Higher Efficiency

58. The combustion efficiency of natural gas is important in terms of lowering GHG emission, irrespective of the status of British Columbia's (or BC Hydro's) electricity imports / exports.[118] From a GHG perspective, consuming natural gas in domestic appliances at 80%-95% efficiency is preferable to using it in gas-fired generation at less than 50% efficiency. Whereas the emissions factor for furnaces is 200 tonnes / GWh, the emissions factor for a CCGT operating at 50% efficiency is almost double that amount (360 tonnes / GWh).[119] Natural gas production has a strong future in British Columbia. The Energy Plan, for instance, expresses government's intent to "take B.C.'s oil and gas sector to the next level to enhance a sustainable, thriving and vibrant oil and gas section in British Columbia."[120] The provincial budget and fiscal plan for 2009/10 – 2011/12 shows Government's continuing support for the expansion of British

[115] Exhibit B-3, Response to Terasen IR 1.3.1.

[116] Transcript, Vol. 3, at 270-271.

[117] Special Direction 10, s.3

[118] Transcript, Vol. 12, at 2171-2173..

[119] See Exhibit C13-5, at 75 (rebate according to efficiency rate). Exporting natural gas for consumption in a gas-fired generator could still reduce GHG's in the Western Interconnection, although to a lesser extent that if it is consumed in domestic applications, if it displaces coal-fired generation. According to BC Hydro's 2007 CPR, Exhibit B-4, Response to BCSEA IR 2.28.1, Attachment 1, at 121, the GHG emission intensity factor for natural gas combustion is 180 tonnes/GWh (it appears this assumes 100% efficiency). Thus, the emissions factor for natural gas consumption at 50% efficiency is 360 tonnes/GWh, which is better than the emissions factor assigned to BC Hydro's imports in 2006 of 550 tonnes / GWh.

[120] Exhibit C13-5, at 64.

Columbia's "abundant natural gas resources."[121] The same logic that favours the consumption of natural gas in high efficiency appliances applies regardless of where the natural gas is produced.

D. The Price of Natural Gas Consumption Within BC Includes the Cost of Carbon

59. The optimal balance of energy sources is achieved through efficient pricing, allowing British Columbians to make their own decisions regarding the appropriate energy source for particular end uses and paying the associated cost. This requires both electricity and the energy alternatives to be priced efficiently from a resource cost perspective. BC Hydro's opposition to Electric Load Avoidance DSM based on its potential to increase consumption of natural gas within BC fails to account for the fact that the cost of associated GHGs is already factored into the natural gas resource cost by virtue of consumers having to pay the carbon tax. Customers are expected to respond to that price signal by reducing consumption. The focus in this proceeding should instead be on getting the right price signals on the electricity side that reflect BC Hydro's marginal cost of supply.

60. The Province's Strategic Plan 2009/10-2011/12 emphasizes the role of the carbon tax in sending appropriate price signals to enabling customers to make choices with respect to energy consumption: "The tax has the advantage of providing an incentive without favoring one way to reduce emissions over another. It gives British Columbians a choice on how they wish to adapt their behavior to reduce their consumption of fossil fuels."[122]

61. Although BC Hydro has referred to its own emissions associated with FNU3 and Burrard as GHG-free after 2016 by virtue of a legislative requirement to purchase offsets, obviously the emissions within British Columbia associated with the operations of these facilities are not suddenly disappearing in 2016. The effect of offsets is really to add the cost of GHGs on to BC Hydro's cost of acquiring electricity from gas-fired generation. The requirement to purchase offsets sends efficient price signals to BC Hydro to ensure that it is not incented to generate electricity in this manner without considering the GHG cost. Logically, BC Hydro's GHG argument against Electric Load Avoidance DSM should fall away if consumers of natural

[121] Exhibit C13-5, at 79.
[122] Exhibit C13-6, The BC Strategic Plan 2009/10-2011/12.

gas in BC purchased offsets. Natural gas consumers are, of course, currently free to purchase offsets but are not obligated to do so. Instead, domestic natural gas consumers are required to pay the carbon tax.[123] The carbon tax provides the desired price signal that would be provided by acquiring offsets.

62. BC Hydro has implicitly acknowledged that offsets and the carbon tax provide alternative price signals for GHG emissions[124] by requesting confirmation from the Province that it will not be necessary for BC Hydro to purchase offsets and pay the carbon tax after 2016.[125] The fact that BC Hydro received that confirmation from the Province[126] reinforces that the Province shares BC Hydro's view in this regard.

63. The Terasen Utilities are not suggesting that offsets are merely a "paper exercise", in the pejorative sense, as BC Hydro has understood. Rather, the submission is that the carbon tax and offsets are different ways of achieving a real, measurable reduction in GHGs through efficient pricing. The amount of the carbon tax paid in respect of domestic natural gas consumption and the amount of offsets required by BC Hydro to address emissions from its gas-fired generation would reflect the relative efficiency of end use consumption (80-95%) versus gas-fired generation (30% for Burrard). Ultimately, the right pricing in either case should result in the efficient amount of consumption.

64. Later in these submissions we address the fact that BC Hydro's GHG offsets for its gas-fired generation are unlikely to be acquired exclusively from within BC, meaning that the GHG benefit that forms the basis of the offset occurs regionally. Offsets within BC have the same value from a climate change perspective as offsets acquired outside BC, but acquiring offsets exclusively within BC will cost upwards of three times as much for BC Hydro's customers. This is another illustration of the importance of taking a regional view to GHG emissions, and not examining only provincial GHG emissions.

[123] Transcript, Vol. 6, at 872.

[124] Transcript, Vol. 6, at 866 (BC Hydro's witness acknowledged that both offsets and carbon taxes provide "provide an economic disincentive..."; see also Transcript, Vol. 6, at 871-872.

[125] Transcript, Vol. 6, at 823-824; Transcript, Vol. 6, at 870 (confirming Ms. Van Ruyven's statement).

[126] Transcript, Vol. 6, at 823-824.

65. In sum, on the natural gas side of the resource analysis, efficient pricing has been achieved by the GHG emissions associated with the consumption of the natural gas being subject to the carbon tax or a requirement to purchase offsets. The task at hand is to ensure that electricity is also priced appropriately.

E. Summary Regarding Regional GHG Emission Reduction and Efficient Pricing of GHGs Within BC

66. BC Hydro's objection to Electric Load Avoidance DSM is rooted in the assumption that natural gas is the logical alternative energy source. BC Hydro discounts the future potential for British Columbians to adopt other alternative energy sources without considering the effect low electricity rates have on the development of the market for these alternatives. The potential to reduce GHG emissions on a regional basis, combined with the obligation on British Columbians to pay the carbon tax on domestic gas consumption, eliminates BC Hydro's primary policy basis for opposing Electric Load Avoidance DSM. BC Hydro should be pursuing Electric Load Avoidance DSM to the economic benefit of BC Hydro ratepayers as a whole with the comfort that its initiative is consistent with the worthwhile objective of mitigating climate change.

VI. EXISTING POLICY FRAMEWORK SUPPORTS EFFICIENT CHOICES AMONG ENERGY SOURCES

67. BC Hydro must, by virtue of section 44.1(2)(b) and (f) of the UCA, explain why it is not pursuing cost-effective Electric Load Avoidance DSM to reduce (all else equal) electricity rates for its customers. BC Hydro's approach has been to frame the Electric Load Avoidance DSM issue as a policy choice between British Columbians using clean electricity or GHG-emitting natural gas for particular end uses.[127] A more nuanced approach is required, which recognizes the benefits to customers in terms of lower rates (all else equal), the availability of an increasing variety of energy alternatives to electricity, regional GHG benefits, and the fact that gas consumers in BC must pay for GHG emissions through the carbon tax as a form of price signal. In this Part the Terasen Utilities makes the following points:

[127] See, for instance, BC Hydro Submissions, at 51-71

(i) Where alternatives to electricity exist for particular end use applications, the objective should be to identify, in the words of the Energy Plan, the "right fuel, for the right activity, at the right time".

(ii) Electric Load Avoidance DSM can be used to counteract inefficient price signals inherent in rates that primarily reflect embedded costs that can cause customers to adopt electricity as an energy source where it is not efficient to do so from a TRC perspective. Customers are free to choose the right fuel for their purposes based on more efficient price signals. This cannot be equated with being "pro-natural gas".

(iii) The Province's pursuit of electrification initiatives reflects its policy of "the right fuel, for the right application, at the right time", and is not evidence of Government opposition to Electric Load Avoidance DSM.

(iv) The *Greenhouse Gas Reduction Targets Act* ("GGRTA") is not an appropriate basis to preclude BC Hydro from pursuing cost-effective Electric Load Avoidance DSM for the benefit of its customers.

(v) Electric Load Avoidance DSM represents an opportunity to reinforce the need for British Columbians to consider energy efficiency.

(vi) BC Hydro's concern about customers "locking in" to a bad fuel choice is misplaced, and BC Hydro should be concerned about the impact of its policies on its customers as a whole.

68. BC Hydro has an opportunity to demonstrate initiative in advancing Government policy through the pursuit of cost-effective Electric Load Avoidance DSM.

A. "Right fuel, for the Right Application, at the Right Time"

69. BC Hydro says that it is awaiting a clearer government directive before pursuing Electric Load Avoidance DSM.[128] However, Government's current neutral position on energy choice is not a policy void. The Energy Plan identifies a future role for electricity, natural gas, and alternative energy sources supplemented by natural gas.[129] The policy emphasis in the Energy Plan is on the importance of making efficient choices among energy sources available for particular end uses, rather than expressing a single preference for any energy source. For example:

[128] Transcript, Vol. 3, at 281-282

[129] Exhibit B-1-1, Appendix B1 at 24.

> It is important for British Columbians to understand the appropriate uses of different forms of energy and utilize the right fuel, for the right activity at the right time. There is the potential to promote energy efficiency and alternative energy supplemented by natural gas. Combinations of alternative energy sources with natural gas include solar thermal and geothermal. [130]

70. Although Mr. Elton at one point rather dubiously characterized the above quoted passage from the Energy Plan as "just one of those good statements that people put into these kinds of policies" as opposed to being an expression of policy,[131] BC Hydro did acknowledge on other occasions that Government policy emphasizes energy efficiency.[132] It would be at odds with this policy for Government to state a preference for one energy source, for all activities, for all time. BC Hydro customers will benefit from BC Hydro applying the policy of "the right fuel, for the right activity, at the right time".[133]

B. Efficient Price Signals *Versus* Being "Pro-Natural Gas"

71. BC Hydro characterizes Electric Load Avoidance DSM as "an action by BC Hydro, as part of its DSM programs, to financially incent customers (who would otherwise select electricity as the energy form) to select natural gas as the energy form."[134] The use of financial incentives is an important aspect of Electric Load Avoidance DSM; however, the implicit suggestion that pursuing cost-effective Electric Load Avoidance DSM requires BC Hydro to be "pro-natural gas" is not correct.

72. Cost-effective Electric Load Avoidance DSM acts in conjunction with the existing conservation rate structures (such as the RIB rate), to *counteract* the fact that electricity rates based on embedded costs encourage customers to adopt electricity as an energy source

[130] Exhibit B-1-1, Appendix B1 at 24; Exhibit C13-5 at 61.

[131] Transcript, Vol. 3, at 280-281. Contrast this statement to Mr. Elton's characterization of other parts of the energy Plan as deliberately allowing for flexibility. In response to a question from Mr. Oulton that there is no legislated requirement on the Burrard timetable, Mr. Elton stated at Transcript, Vol. 5, at 694 that "There is no legislative requirement, therefore it's one of those areas where you – I think you seek to be in the right – in the same direction as government policy, and you seek to use the flexibility that they've offered."

[132] Transcript, Vol. 3, at 281-282.

[133] In effect, this results in BC Hydro returning to the policy it pursued until the 2007 Rate Design proceeding, exemplified by the following statement on its website: "We encourage customers to think about how they use energy. It's important to match your energy source to its best use. Electricity is best suited for lighting and powering our appliances and televisions, whereas natural gas is ideal for space and water heating." Exhibit C13-9, at 4.

[134] BC Hydro Submissions, at 62, lines 3-5.

where the TRC analysis demonstrates that electricity is not the most efficient fuel alternative for particular end uses. BC Hydro's low electricity rates have the unintended consequence of constraining customer choice, as illustrated by the fact that the measures identified in the CPR as having a TRC of one or more all resulted in a negative or excessive payback period for customers.[135] Electric Load Avoidance DSM drives customers to make decisions among energy sources recognizing BC Hydro's avoided marginal cost of supply, unconstrained by relative price differences in capital costs or embedded cost-based electricity rates. Natural gas was the only fuel alternative studied in the 2007 CPR, but heat pumps and other alternative energy systems also represent potential alternatives to electric baseboards, for example, that a customer could choose from when the economics make sense or where a customer's personal values play an important role in the choice. BC Hydro should not assume that electricity will be each customer's moral choice as they appear to do in their final argument.[136] Once the inefficient price signals inherent in the existing electricity rates are mitigated by Electric Load Avoidance DSM incentives, customers may choose other alternatives.

73. BC Hydro cites at page 62 of its submission's Mr. Elton's evidence that "[BC Hydro has] sought clarification on this and received the answer, it isn't government policy to encourage fuel switching from electricity to natural gas." BC Hydro also cites Ms. Van Ruyven's statement that: "I don't believe there is any government policy that specifically says that BC Hydro should encourage fuel switching from electricity to natural gas". There is nothing in either of these statements to suggest anything other than a neutral stance on fuel choice.

74. Ms. Van Ruyven also recounted government representative as indicating that government would not formulate a policy that would result in BC Hydro promoting a program that would incent an increase in GHG emissions within B.C.[137] BC Hydro has not taken such an unequivocal stance with respect to its own programs that would result in increased GHG emissions in the province. FNU3, for instance, results in greater GHG emissions within British Columbia.[138] BC Hydro's response to this is to cite carbon offsets as negating the physical GHG

[135] Exhibit B-4, Response to BCSEA IR 2.28.1, Attachment 1, at 108 & footnote 65.

[136] BC Hydro Submissions at 62, line 7, item (2).

[137] BC Hydro Submissions at 63.

[138] FNU3 results in less GHGs per GWh, but the generation capacity will increase significantly such that GHGs will increase overall. See Exhibit B-12, Response to Terasen IR 3.8.1.

emissions; but, as discussed previously, natural gas consumption is subject to an equivalent carbon pricing mechanism in the carbon tax. All of this illustrates that Government policy must be more nuanced than to preclude BC Hydro initiatives that result in GHGs in the province.

75. The Terasen Utilities are not suggesting that the Province has a policy of favouring a particular energy source for particular end use applications, a misconception that seems to underlie a number of BC Hydro's submissions.[139] Rather, the Terasen Utilities rely on the express wording of the Energy Plan and the Government's stated preference for choosing the "right fuel, for the right activity, at the right time".

76. Where energy alternatives do exist, it is imperative that the appropriate rate and incentive mechanisms, as well as consistent messaging, are put in place to inform available energy choices and free customers to make choices among energy sources that are efficient from a TRC perspective for a particular application. BC Hydro has acknowledged that providing right price signals can "encourage customers to make energy efficient choices."[140] BC Hydro will apply Provincial policy by encouraging customers to use energy more efficiently through Electric Load Avoidance DSM.

C. Electrification Initiatives

77. BC Hydro cited in opposition to Electric Load Avoidance DSM that "one of the most significant GHG implementation uncertainties from a fuel switching perspective is the extent of BC Government electrification initiatives."[141] BC Hydro provided two examples of electrification initiatives relating to the adoption of electricity at truck stops and ports in place of diesel and marine fuel.[142] To the extent that BC Hydro is suggesting that these initiatives are the beginning of a trend towards mass electrification, or evidence of Government opposition to Electric Load Avoidance DSM, it is reading far too much into these initiatives. BC Hydro has

[139] For example, BC Hydro's response on page 63 to the Energy Plan's reference to "right fuel, for the right activity, at the right time" is to observe that "Noticeable by its absence is any reference to encouraging fuel switching from electricity to natural gas…". The inclusion of such a statement would be at odds with the Province's emphasis on the importance of choosing the "right fuel, for the right activity at the right time".

[140] Exhibit C13-9, at 5 (IR response from RIB Application proceedings)..

[141] Exhibit B-4, Response to BCSEA IR 2.29.2, at 48.

[142] Exhibit B-4, Response to BCSEA IR 2.29.2.

stated that the Province is neutral as to fuel choice.[143] Government's support for the development of natural gas is evident.[144] The Province has also promoted initiatives that use, for instance, liquefied natural gas to fuel heavy-duty trucks.[145] In short, the electrification initiatives cited by BC Hydro, like the Province's support for the LNG initiative cited above, are simply a reflection of the Province's policy favouring "the right fuel, for the right activity, at the right time".

D. "Provincial" GHG Emissions

78. BC Hydro interprets the provincial emissions reduction target in the GGRTA as a prohibition against pursuing cost-effective Electric Load Avoidance DSM, at least in so far as the alternative fuel is natural gas. There are several reasons, addressed below, why the GGRTA is not an appropriate basis to preclude BC Hydro from pursuing of cost-effective Electric Load Avoidance DSM for the benefit of its customers.

(ii) Mitigating Climate Change *versus* Pursuing a Target

79. BC Hydro's interpretation of Government policy is exemplified by Mr. Elton's response to the question of who benefited from the position BC Hydro was taking in a circumstance where GHGs were being reduced overall and BC Hydro customers were paying lower rates. He replied that the beneficiaries are "[t]he people who are living in a province that achieves its targets."[146] This analysis unjustifiably elevates to the status of ultimate objective one *means* by which Government has chosen to pursue its ultimate objective of mitigating climate change associated with GHG emissions.

80. The passages from the Energy Plan quoted by BC Hydro in its Submissions in support of this argument regarding the GGRTA[147] are ultimately emphasizing climate change. The Premier noted for instance, that "The world has turned its attention to the critical issue of global warming" and indicated that the ultimate purpose of the steps outlined in the plan was "arrest the growth of greenhouse gases and reduce human impacts on the climate".[148] The

[143] Transcript, Vol. 3, at 275.
[144] See, e.g., Energy Plan, Exhibit C13-5, at 61; 2010/2011 Strategic Plan, Exhibit C13-6.
[145] Exhibit C13-5, at 60.
[146] Transcript, Vol. 3, at 289.
[147] BC Hydro Submissions, at 51.
[148] Exhibit B-1-1, Energy Plan, at 4.

passage from Message from the Government in the Climate Action Plan similarly opens with the statement "Global warming is the challenge of our generation."[149] The GGRTA target and Government's ultimate objective of climate change mitigation are aligned in most cases, which makes the GGRTA a useful tool in combating climate change. However, where the legislated target and the ultimate objective are at odds, the *means* should not trump the *end goal*. It is important in the case of Electric Load Avoidance DSM to keep in mind that the ultimate objective behind the legislation is mitigating climate change because the associated GHG emission reductions are regional. BC Hydro customers (and British Columbians generally) benefit from lower GHG emissions, irrespective of whether the reduction occurs in BC or across the BC-US border.[150]

81. The Province has used other legislation to achieve its climate change objectives, which do not focus exclusively on provincial emissions. The UCA, i.e. the legislation that defines the Commission's jurisdiction, refers to "government's energy objective" as being "to encourage public utilities to reduce greenhouse gas emissions". Although the GGRTA focuses on provincial emissions, the Government objective identified in the UCA is unqualified by reference to "*provincial*" GHGs or the province's GHG targets under the GGRTA. The Western Climate Initiative ("WCI"), to which the Province is a member, is a regional initiative to combat climate change.

82. Government's promotion of natural gas development in the Province[151] is another example of a circumstance where taking BC Hydro's approach would ultimately run counter to the Province's support for mitigating climate change. The production of natural gas contributes 18% of BC's total GHG emissions.[152] However, the consumption of natural gas in end use

[149] British Columbia Climate Action Plan,, available at: <http://www.livesmartbc.ca/attachments/climateaction_plan_web.pdf>, at 1.

[150] Transcript, Vol. 6, at 811-812.-

[151] Exhibit B-1-1, Appendix B1, at 32. Exhibit C13-5, at 64. The Energy Plan states that it "is designed to take B.C.'s oil and gas sector to the next level to enhance a sustainable, thriving and vibrant oil and gas sector." Government has since continued to sell land for resource development and the sales have attracted record levels of land sale bonuses in the last two years. See Exhibit C13-5, at 62 (Minister Neufeld's Press Conference Statement). In Exhibit B-12, Response to BCUC IR 3.248.1, BC Hydro acknowledged this fact. "Land sales in Northwest B.C. significant [sic] increased during 2008, signaling that there could be a strong potential for future development of natural gas reserves in the region."

[152] Exhibit B-1-1, Appendix B1, at 23. Mr. Elton suggested that although government is interested in promoting many activities that will increase GHG emissions in the province the GHG reduction target would have taken

appliances has a significantly lower emissions factor (200 tonnes/GWh)[153] than the emissions factor applied to BC Hydro's imports in 2006 (550 tonnes per GWh).[154] This is still the case where the natural gas is consumed in a CCGT at 50% efficiency to generate electricity (360 tonnes/GWh).[155] Thus, it is better from a climate change perspective to produce and consume natural gas anywhere in the WECC region for direct use applications or for gas-fired generation than it is to generate electricity using a higher emitting energy source such as coal. Coal generation emits about twice the amount of GHG per GWh than does natural gas-fired generation.[156]

(iii) BC Hydro's Regional Approach to Offsets

83. As outlined in Part III of these Submissions, the successful implementation of cost-effective Electric Load Avoidance DSM results in a direct benefit to BC Hydro customers in the form of lower rates (all else equal). BC Hydro is already pursuing other policies for the benefit of its customers that result in provincial GHG emissions. FNU3 and the continued use of Burrard, both of which BC Hydro advocates, will generate GHG emissions in the province.[157]

into account these expansions in natural gas development. (Tr. Vol. 3 page 293 lines 14-23). However, at the time the 33% target was announced in the 2007 Throne Speech (Exhibit B-1, page 4-5, footnote 52, link to B.C. News Release on BC joining WCI) the gas production forecasts were indicating only modest growth. (Exhibit B-3, BCUC IR 1.67.1, Attachment 2, Climate Action Plan, Appendix I, page 100-101, which references NRCan's 2006 forecast.) The subsequent pursuit of the Horn River play has resulted in a step change in these forecasts. The CAPP letter filed by BC Hydro (Exhibit B-1-1, Appendix B1, at 23) indicates that "Production from the Horn River Basin shale gas is forecast to grow from approximately 50 mmscf/d million cubic feet per day) in 2009 to approximately 2,700 mmscf/d by 2020. The forecast is derived from a survey of the area operators of the HRPG which requested their anticipated annual drilling well count and the associated production. The well count derived is approximately 80 in 2009, growing to over 200 wells per year in 2016, then maintaining that level. It is anticipated that there could be a total of 2,200 wells producing in 2020." This step change in BC's natural gas production levels will lead to an associated increase in GHG emissions produced in BC.

[153] CPR, Exhibit B-4, BCSEA IR 2.28.1, Attachment 1, at 121 of 138, notes that the number on the record is 180 tonnes/GWh for direct use of natural gas. However, this appears to correspond to 100% efficiency. 90% efficiency, by our calculations, is closer to 200 tonnes per GWh, so we have used this amount in these Submissions.

[154] Exhibit B-4, BCSEA IR 2.28.1, Attachment 1, at 121. Also, it is clear that emissions levels in the WECC regional will remain at this level for some time, as estimated average performance standard in Alberta, Arizona, New Mexico, Montana, Utah, Colorado, Nevada, Idaho, and Wyoming. A performance standard is the GHG emissions level above which **offsets** must be acquired. (Exhibit B-1, p. 4-20 lines 14-21).

[155] Exhibit B-1, at 4-20, lines 4-10: "California, Washington State and Oregon require thermal plants to offset to the equivalent of a CCGT, This results in the California, Washington State and Oregon performance standards being set at 360 tonnes of GHG per GWh."

[156] Exhibit B-1-1, Appendix H, at 10-11.

[157] Transcript, Vol. 6, at 865-866. GHG emissions associated with FNU3 is discussed in Terasen IR 3.8.1. The Terasen Utilities take no position on whether FNGU3 is in the public interest, and recognize the value to BC Hydro of continuing to operate Burrard.

Unlike Electric Load Avoidance DSM, running these facilities does not deliver an offsetting GHG reduction elsewhere in the Pacific Northwest. These initiatives illustrate the need to balance government's interest in reducing GHG emissions against other competing objectives.

84. BC Hydro seeks to distinguish the "provincial" emissions associated with Burrard and FNGU3 from the emissions associated with domestic natural gas appliances by pointing to the requirement to offset the GHG emissions associated with its facilities after 2016, and the absence of any existing obligation on natural gas consumers to offset GHG emissions.[158] The inconsistency of BC Hydro's reliance on offsets with its failure to recognize the carbon tax as a means for pricing carbon was discussed above. In the context of the regional approach to GHG emissions it is noteworthy that BC Hydro will likely purchase offsets outside the province in order to reduce the costs of purchasing those offsets.[159] This requires a regional perspective towards GHG emissions, analogous to that being advocated by the Terasen Utilities. In the case of offsets acquired outside of BC, the GHGs will be emitted in British Columbia, while the GHG reduction that forms the basis for the offset will be occurring outside of British Columbia. There is no logical distinction between acquiring offsets from outside British Columbia and (i) using electricity "freed-up" by Electric Load Avoidance DSM to displace gas or coal-fired generation on the margin, or (ii) exporting BC's natural gas to reduce GHG emissions in the WECC region. Extra-provincial offsets are being considered by BC Hydro because they will cost less and ultimately save customers money.[160] Electric Load Avoidance DSM should also be considered for this reason, among others.

E. Conflicting Messages to the General Public

85. Counsel for BCSEA-SCBC raised in his Opening Statement a concern that promoting electricity to natural gas Electric Load Avoidance DSM programs would create confusion with regard to reducing GHG emissions and burning fossil fuels.[161] BC Hydro's

[158] Exhibit B-12, Response to BCUC IR 1.22.2; BC Hydro Submissions at.67, lines.8-11.

[159] Transcript, Vol. 9, at 1532-1534.

[160] Exhibit B-1, at 4-10 and Table 4-2; The B.C. only case for establishing the cost of offsets was not considered likely by Natsource in its modeling of the cost of offsets. Table 4-2 indicates that the expected cost of offsets from a B.C. only case would be three times or more the expected cost of offsets if they were acquired from within the WECC.

[161] Transcript, Vol. 3, at 222-223.

witnesses echoed this position during the hearing[162] and BC Hydro repeated it in its Submissions.[163] There is no evidence to support this contention that the public will be confused. Rather, the evidence is that the Province has emphasized in the Energy Plan the importance of "for British Columbians to understand the appropriate uses of different forms of energy and utilize the right fuel, for the right activity, at the right time". BC Hydro, until after the 2007 Rate Design Application proceeding, adopted a nuanced approach, as exemplified by its website encouraging customers to match their energy source to its best use.[164] Other utilities in the Pacific Northwest (the examples in the record are Avista and Puget Sound Energy) continue to take a more nuanced view, with the apparent approval of regulators,[165] in the confidence that people will understand the value in making efficient fuel choices. The pursuit of Electric Load Avoidance DSM presents an opportunity to reinforce the need for British Columbians to consider and "understand the appropriate uses of different forms of energy".[166]

F. Lasting Implications of Customer Decisions Regarding Energy Source

86. During the hearing BC Hydro's witnesses suggested that BC Hydro was reluctant to encourage the adoption of natural gas as an energy source for particular end uses out of concern that customers who switch to another energy source would be subjected to high future gas prices and operating costs.[167] The concern here, as characterized by BC Hydro, is that "[i]f that choice ends up to be a bad choice, particularly if that choice was originally made when all the signposts were that electrification of space heating may be required to meet climate action targets, BC Hydro could be seen by that customer in a bad light as a result of such encouragement. Recall, customers have long memories."[168] There are a number of problems with BC Hydro's approach.

[162] Transcript, Vol. 3, at 284.

[163] BC Hydro Submissions at 71, l.25 to 72, l.15

[164] In response to Terasen's Information Request in BC Hydro's 2007 Rate Design Application proceedings, BC Hydro stated that "in the past, BC Hydro encouraged customers to use natural gas instead of electricity for space heating, based on economic and environmental considerations. BC Hydro is reviewing this practice in light of the 2007 Energy Plan." See Exhibit C13-9, at page 5.

[165] See for instance, Exhibit C13-9, at 11-12, the staff decision from the Washington Utilities Transportation Commission in respect of Puget Sound Energy's programs.

[166] Exhibit C13-5, at 61.

[167] Transcript, Vol. 9, at 1521 - 1522.

[168] BC Hydro Submissions, at 66..

87. First, this paternalism is at odds with the Province's approach to facilitate British Columbian's ability to make energy choices based on efficient price signals, as exemplified by the carbon tax. The Province's Strategic Plan 2009/10-2011/12 emphasizes the role of the carbon tax in sending appropriate price signals *to enable customers to make choices* with respect to energy consumption.[169]

88. Second, BC Hydro's vision of the future from which it is protecting its customers is suspect. With respect to BC Hydro's reference to natural gas price increases, BC Hydro's witnesses testified as to their expectation that the sustainable long-term gas prices will be in the $6 to $8 per MMBtu range.[170] All of the gas price forecasts provided by BC Hydro (except that of its own internally developed high gas price forecast and internally developed weighted average) reside below or in the lower part of this range until 2020.[171] In contrast, electricity prices have been rising steadily and will continue to do so.[172]

89. Third, in making this judgment for customers, BC Hydro is according insufficient weight to the fact that its customers *as a whole* will pay higher electricity rates (all else equal) as a result of the customer choosing electricity over another energy source due to the embedded cost-based electricity rates or relative capital cost of adopting a particular alternative energy source.[173] Customers paying higher rates in the future (all else equal) may look back on BC Hydro's opposition to counteracting inefficient price signals that have the effect of encouraging electric space and water heating load as a "bad" decision. This is particularly so where GHGs can also be reduced on a regional basis. Once individual customers faced with a choice among energy sources for particular end uses choose electric appliances as a result of those price signals, BC Hydro is locked in to that decision, and customers as a whole must pay for it.

90. There is no justification for this paternalism evidenced in BC Hydro's submission. BC Hydro should pursue Electric Load Avoidance DSM as a means of establishing more

[169] Exhibit C13-6, The BC Strategic Plan 2009/10-2011/12.
[170] Transcript Vol. 10 at 1888-1889.
[171] Exhibit B-32.
[172] Exhibit B-10, at 25.
[173] See, for example, Exhibit B-4, Response to BCUC IR 2.206.3.

efficient price signals, and allow the customers to make the choice as to the energy source they adopt for particular end uses.

G. Summary

91. Electric Load Avoidance DSM can be used to counteract inefficient price signals inherent in rates based to a significant extent on embedded costs, with resulting economic benefits to BC Hydro customers and a provincial and regional GHG reduction. Mitigating increases in electricity rates through cost-effective Electric Load Avoidance DSM, and reducing GHG emissions in the process, is aligned with provincial policy as reflected in the Energy Plan and “government’s energy objectives”. It is also in the public interest, which is the ultimate test to be applied by the Commission in this Application.

VII. COMMISSION DETERMINATIONS AND NEXT STEPS

92. As indicated previously, the Terasen Utilities are cautiously optimistic about BC Hydro’s new overtures to investigate Electric Load Avoidance DSM. However, certain parameters that BC Hydro has placed on the inquiry in the high level discussion that appears on pages 57-59 of its Submissions suggest that there remain fundamental disagreements among the intended participants in the study process that require the Commission’s intervention at this time. The Terasen Utilities respectfully submit that the evidence on the record supports the following findings, which should be made express in the Commission’s decision in order to help to frame the study:

(i) The pursuit of cost-effective Electric Load Avoidance DSM can be used to achieve efficient pricing, which in turn will allow customers to make appropriate fuel choices.

(ii) To the extent that customers faced with efficient price signals adopt another energy source it will contribute to BC Hydro’s efforts to close the load-resource gap, thus avoiding the need to acquire new higher cost electricity supply for that portion of the demand. This will result in lower electricity rates (all else equal) for BC Hydro customers as a whole.

(iii) Using cost-effective Electric Load Avoidance DSM to achieve efficient pricing is consistent with the Energy Plan’s emphasis on the “right fuel, for the right activity, at the right time”, and is consistent with the Province’s neutral position on choice of energy source.

(iv) The potential for GHG reductions outside of the province as a direct result of pursuing cost-effective Electric Load Avoidance DSM suggests that BC Hydro should be pursuing cost-effective Electric Load Avoidance DSM.

(v) The way in which the GGRTA measures GHG emissions, i.e. on a provincial basis, does not and should not prevent BC Hydro from pursuing cost-effective Electric Load Avoidance DSM to reduce rates for BC Hydro customers (all else equal). The presence or absence of a requirement to offset GHG emissions is not determinative in the context of Electric Load Avoidance DSM as the energy alternatives adopted by customers will have the cost of carbon priced in to them by way of the carbon tax.

93. BC Hydro acknowledges the Commission's jurisdiction to direct a study of Electric Load Avoidance DSM.[174] The Commission should issue the following additional directions to BC Hydro to guide its future work. These directions are consistent with the evidence in this proceeding and are appropriate in the circumstances:

(i) The cost-effectiveness of Electric Load Avoidance DSM should be determined with reference to the Total Resource Cost (TRC) test.

(ii) In performing a TRC analysis for Electric Load Avoidance DSM, BC Hydro should be using an updated avoided cost (before line losses) of at least \$120/GWh. In the case of programs directed at space heating load, BC Hydro should be using time of delivery weighting per the approach adopted in Exhibit B-73.

(iii) Cost-effective measures (i.e. those with a TRC ratio of benefits to costs of greater than 1.0) should not be eliminated from consideration as a means of addressing the load-resource gap based on a simple payback analysis using current rates paid by BC Hydro customers.

(iv) Part of BC Hydro's study must include exploring different incentive models within the framework of Electric Load Avoidance DSM.

94. The Terasen Utilities submit that it is unnecessary to reject any part of the LTAP provided that appropriate Commission directives are in place and that the current two-year LTAP cycle is maintained.

[174] BC Hydro Submissions, at 22

VIII. CONCLUSION

95. BC Hydro has an opportunity to close the forecasted load-resource gap by pursuing Electric Load Avoidance DSM in tandem with its proposed *load reduction* DSM. BC Hydro customers will benefit from lower rates than would otherwise be the case if BC Hydro pursues Electric Load Avoidance DSM having a TRC benefit/cost ratio of more than one. British Columbians will benefit from reduced GHG emissions in the region. The legislative and policy context, exemplified by "government's energy objectives" and the Energy Plan policy of "right fuel, for the right activity, at the right time", supports the pursuit of cost-effective Electric Load Avoidance DSM in priority to acquiring higher cost supply. The Terasen Utilities look forward to working productively with BC Hydro and other stakeholders to develop appropriate terms of reference for the further study of Electric Load Avoidance DSM in line with the Commission's direction.

ALL OF WHICH IS RESPECTFULLY SUBMITTED,

[Original signed by Matthew Ghikas]

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Matthew Ghikas
Counsel for the Terasen Utilities

[Original signed by Song Jin Hill]

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Song Jin Hill
Counsel for the Terasen Utilities

April 27, 2009

WRITTEN SUBMISSION FROM:

CLEAN ENERGY ASSOCIATION OF BC

Clean Energy BC

Friday, August 10th 2012
BC Hydro
333 Dunsmuir Street
Vancouver, BC
V6B 5R3

Attention: Mr. Doug Little, Vice President, Energy Planning and Economic Development
Mr. Randy Reimann, Director Resource Planning

Dear Gentlemen:

Reference: Draft IRP TAC Review Comments due August 10th 2012

Clean Energy BC appreciates the opportunity to review BC Hydro's Draft IRP released this past May. Our goal in making this submission is to focus on the immediate electricity energy challenges facing BC. At the same time we must keep in mind broader societal and public policy issues that subsequent generations will face based on the decisions being made as part of the 2012 IRP – after all the next IRP is not scheduled to take place for another five years.

The heart of our IRP review relates to the disruptive forces brought about by uncertainty – uncertainty that results from underestimating load and overlooking options that in turn lead to contingencies being the mainstay of short term electricity generation policy. For the private sector, establishing certainty leads to efficiencies being realized that positively impact all ratepayers, the public at large, and First Nations communities now and for the future.

BC is poised for rapid and sustained economic growth as articulated in the Jobs Plan. To realize this growth, BC must adopt an IRP that provides certainty regarding a number of key business interests related to this potential growth, such as the stable long-term price of electricity, transmission expansion to support key industries and projects, and procurement to meet the expected need for energy and capacity.

Below, we address our IRP related issues.

Demand Side Management (DSM):

Clean Energy BC applauds BC Hydro and the provincial government in their efforts to conserve electricity. It is highly likely conserving electricity will in a few years become similar to recycling efforts. Virtually all segments of society today are aware of the need to recycle papers and pop

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cans and have made the behvioural shifts to do so. At some point in time these same members of society will turn off lights as second nature.

However, we must remain diligent, perhaps even skeptical, about the overall long term success of DSM relative to its targets and expectations. Are the IRP's DSM assumptions actually realistic? CEBC has considerable doubt the targets are realistic and remains concerned about the implications for future energy supply if the targets cannot be realized.

The IRP's Base Plan is relying upon almost 10,000 GWh/year of DSM energy savings by F2021, such that the growth rate of the energy requirement after DSM is reduced substantially below the population growth rate of 1.5% per year. Placing this great a reliance on DSM savings constitutes a very significant risk to the Plan.

Based on the observation of recent history, this level of savings has never been realized despite the hundreds of millions of dollars invested to date. BC Hydro's per capita electricity consumption in the residential and commercial sectors has remained virtually flat over the past decade, even though BC Hydro has had some of the most aggressive DSM programs on the continent - and, even though all of those programs have been evaluated by BC Hydro as successful. Nevertheless, per capita load remains virtually constant.

Population growth times per capita consumption leads us to the conclusion that the overall demand <u>after</u> DSM cannot be relied upon to grow at any rate slower than the inherent population growth rate of 1.5% (at least where residential and commercial loads are concerned, setting aside the industrial sector where loads can be forecast by individual participant).

The reasons for the constancy of the per capita consumption are not clear and obvious, but perhaps it can be explained by the "rebound" effect. As we change out our light bulbs from 60 watt to 13 watt – do we not end up leaving this more efficient light on longer because it costs us less? How do we reconcile the local Tim Horton's display screens? A recent visit resulted in a count of seven LED price/product screens where there used to be three screens – all resulting in increased electricity demand. Everyone now has large screen TVs and more appliances.

Whatever the reason, the observed reality is staring us in the face, and the prudent assumption would be to <u>not</u> rely upon savings as large as 10,000 GWh over the coming years – we have not seen these savings realized, net of the rebound, in the past and we should not assume that we will see them any time soon. The Base Plan should be based upon realism and proven performance and actions.

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Load Forecast:

Clean Energy BC has concerns about the seemingly inconsistent load forecasts incorporated in the IRP Base Plan versus those that should flow from the success of the government's Jobs Plan and GHG Reduction Act. The difference in the energy demand-supply gap between the two scenarios is more than 17,000 GWh per year by 2021.

Furthermore, the consequences for greenhouse gas emissions could be staggering, and yet are unmentioned in the Base Plan.

CEBC's calculations highlight these differences in the following table.

		IRP	Provincial Laws	*Note:*	
Outlook for 2021:		Base Case	and Objectives	(i)	
LNG plants		1 and 2	1, 2 and 3	(ii)	
LNG production	MT/yr	10	21		
Demand/Supply Gap	GWh/yr	2,000	19,346	(iii)	
GHG increase	MT/yr	silent	23.6	(iv)	
Calculation notes:					
i) Provincial Laws and Objectives include; BC JobsPlan Targets for LNG plants, the GHG Reduction Targets Act					
	and the electrification and fuel switching Objectives in the Clean Energy Act.				
ii) LNG Plants: LNG3 is the Shell LNG plant. LNG plants 4, 5, and 6 have also been proposed					
iii) Gap: JobsPlan/GHG Act scenario includes electrification of upstream gas activities, which is ignored in IRP Base Case					
iv) GHG increase: JobsPlan/GHG Act scenario is following IRP Base Case approach of no electrification					

Clearly, the success of the government's Jobs Plan in combination with meeting its GHG reduction targets will require a significant amount of additional procurement than is presently portrayed in the IRP's Base Plan.

BC Hydro has not totally ignored the need for this additional energy, but it has relegated it to the status of Contingency Resource Plans. CEBC believes this is inconsistent with the government's stated objectives for its Jobs Plan and its GHG reduction targets. It means the Base Plan makes the implied assumption that both of these significant government initiatives will fail.

What concerns CEBC is that, by relegating this significant energy requirement to the status of contingency planning, BC Hydro sets up no concrete action plan to be ready to serve those

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loads. This creates a huge and unhealthy uncertainty for our industry and other industries that rely on electricity. Given the importance of meeting the targets in the Job Plan, particularly in economically depressed areas of the BC northwest, it seems there is little to be gained by not reflecting the potential economic prosperity in the load forecast. Furthermore, it suggests that the province will be allowed to "drift" by default into a high-emitting gas-based energy future which will totally abandon the province's aggressive war on climate catastrophe.

If it is the government's intention to abandon its leadership on climate change, then that should be made clear to the citizens of BC. On the other hand, if that is not the government's intention, then that too should be made clear, by showing the needed electrification in BC Hydro's Base Plan.

The ***Clean Energy Act 2010*** states as a key objective, "…to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in Britsih Columbia." The IRP needs to reflect how this government policy will be met.

If it is the government's intention to allow the province to drift, by default into a gas-driven energy future, then CEBC wishes to draw attention to **a number of serious business and political risks and inherent uncertainties to this approach.**

Burrard Thermal:

At what point in time does Burrard Thermal actually fall off the resource capacity map? At what point are there no further 'life' extensions sought for this antiquated and inefficient plant? At what point in time do Fraser Valley residents celebrate the fact their fragile air shed need not contend with Burrard? In economic terms, what is the cost for a full renovation of Burrard that could allow it to continue to play a serious role in the province's energy future to the detriment of developing new renewable resources?

Air Shed Issues:

Both the Burrard Thermal and the Sumas II plants have given us illustrations of how much individuals and communities respect their air sheds and how much respect they themselves wish from their air sheds, or more importantly those that 'pollute' those air sheds. With respect to LNG and gas fired electricity generation, how much work has been done or planned to be done on the Kitimat air shed?

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Gas Price Risk:

Clean Energy BC fully recognizes the potential and opportunity for the use of gas-fired generation to optimally locate significant capacity additions, and also the use of gas for energy where there are highly efficient cogen opportunities. We also support the use of gas as a transportation fuel as well as a transition fuel bridging over from both coal and oil fossil fuels wherever possible.

However. if gas is to fulfill a major role in energy production, the province must be very cautious about assuming that the low prices we see for gas today will persist in the future. In fact, if the three LNG proposals are successful, the presence of these plants is intended to give their proponents relief from the "captive market discount" presently inflicted on North American gas prices. Accordingly, these plants will be extremely reluctant to have their electricity costed at the Asian market price for gas.

So, who in fact will carry the gas price risk if BC defaults to a gas-powered future? Will it be BC Hydro's ratepayers, or private sector generators? What appears to be a good deal today may not be such a good deal in the long run. The economics of gas-fired generation with $8 to $10 gas do not look anything similar to the economics with $3 to $5 gas we see today, especially when the next item is considered.

GHG Price Risk:

In terms of leaders and laggards in carbon and GHG policies BC has undoubtedly become recognized in the former category. True, our economic times of today embattle this leadership but we do see other jurisdictions also stepping up to the plate. California and Australia come to mind. Absent firmness and certainty of GHG pricing regimes, North American gas-fired electricity looks like a good deal just now. But, for how long will we be able to 'get away with' not having GHG and carbon pricing?

The economics of gas-fired generation with $80 to $100/tonne greenhouse gas charges do not look anything similar to the economics with the $30/tonne charge we see today.

Also, how can we, in good conscience, counsel our citizens to pursue costly and aggressive energy efficiency measures as a way to save our planet, while on the other hand we abandon the battle by turning to fossil fuels in place of non-emitting renewable generation?

Throw in an increasingly informed and environmentally aware public and electorate. Mix it together with some world-wide economic recovery, and a gas -fired generation strategy may not

Clean Energy BC

look quite so good in the future as it does today. We suggest that pragmatic leadership will find the balance with the strongest and highest component of renewables in the generation mix.

Transmission Development Risk

Transmission lines connect BC to future prosperity and must be optimistically considered in the IRP. Whether it is new interconnections to Alberta that would allow BC Hydro to sell into the Alberta Market, or new transmission lines to support LNG and mines in the BC Northwest, or new transmission lines to interconnect BC's natural gas producers in the BC Northeast, transmission lines present the opportunity for new customers to access the same industrial power benefits as their predecessors in the past decades. This is even more important today as many companies are now looking globally to deploy capital to develop resources, and one key feature is the supply of reliable electricity at a reasonable cost. Attracting these companies to develop our resources in BC is fundamentally important to our economic future. In this regard, positive and proactive approaches to planning and building transmission, including upgrades of the existing network, are important to laying the groundwork for future transmission development.

It is important to note that much of the development timeline for new transmission includes planning and permitting, both of which are in control of BC Hydro and the Government. Given the recent changes by government to review the permitting process for clean energy, mining, and other major projects, it may be appropriate to review the process for transmission development to determine if any efficiencies can be realized to shorten the development process and timeline.

The Clean Energy Association notes that the private sector is in an excellent position to collaborate with BC Hydro to expand the transmission system through different contracting / procurement models, such as joint ventures and public-private partnerships. Such alternative models can provide savings of time and money to ratepayers, transmission customers, and BC Hydro by allowing the private sector to shoulder and manage development risk.

A False Impression of the Cost of New Renewable Energy:

The forces driving the province to favour a gas-powered future also include a misperception of the expected cost of new renewable energy particularly on a total life cycle cost basis that includes construction, operations and maintenance. We recognize that the cost estimation of energy resource options is a frustrating exercise in trying to hit a moving target. However, we must direct your attention to the recent study undertaken by international consultants Garrad

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Hassan for the Canadian Wind Energy Association. This report was filed with BC Hydro and the government in June, but this data has yet to be incorporated in the Plan.

According to Garrad Hassan, the costs for wind energy generation have been dropping dramatically over the past few years since BC Hydro obtained any market verification. GH now estimates that BC has up to 20,000 GWH per year of wind energy available at costs which should be competitive with those for Site C (below $100/MWh), and most of these sites could be developed much more quickly.

Further studies of hydro resources might show similar cost improvements. Of course, in the final analysis, studies will never give the ultimate answer. Only a competitive call will give that answer. Which is why the call process must be undertaken as quickly as possible, and on a scale adequate to fulfill the real need, assuming the success of the government's plans.

A call could be mounted that includes both energy and capacity. It could include both gas-fired generation and pumped storage, and it could even include Site C as one of the participants.

Clean Energy Association of British Columbia (CEBC)

As of April 1st 2012 BC Hydro lists 74 production partners with EPA's delivering 14,242,GWh of energy from 3,271 MW of capacity as well as another 52 partners who are developing a further 8,720 GWh of energy from 2,317 MW of capacity. The majority of these partners are members of CEBC. These projects bring significant benefits to all British Columbians by virtue of the fact all project risks are borne by their owners and not by either BC Hydro, the BC government or residential, commercial or industrial ratepayers. Private sector projects are required to meet ever increasingly stringent environmental, regulatory and permitting standards. The bidding process that results in developers being awarded EPA's (electricity purchase agreements) ensures that their electricity prices are very competitive when compared to no to low GHG generation alternatives, whether built by BC Hydro or others.

The role of First Nations in shaping the energy landscape of the province cannot be over stated. Today 125 Indian bands are involved in the clean energy sector.

British Columbia has considerable opportunities for economic development whether from LNG, mine sites, population growth or electric vehicles. We are in fact a frontier as exemplified in the northwest – building new roads, new power generation, new transmission and new mines and new export industries with LNG shipments to Asia.

What BC needs today is a solid 'energy and electricity' vision based on achieving the highest development of renewables possible and a continuation of the leadership on climate change,

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rather than an abandonment of our achievements to date – with gas-fired generation providing capacity for reliability and local capacity , and filling short-term energy imbalances. The IRP needs to reflect a better balance for the future between gas-fired and renewable energy generation; in BC we have the cost-effective resource opportunities to achieve this.

In conclusion we believe BC's window of opportunity will not remain open for ever, including the climate change imperative. We live in globally competitive times and must not be afraid of making the best decisions for the short and long terms. This IRP is the opportunity to send positive signals regarding energy supply, transmission and the fundamental importance of the infrastructure and certainty for supporting a prosperous future for British Columbia.

Thank you.

Sincerely,

Paul Kariya

Executive Director

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WRITTEN SUBMISSION FROM:

COMMERCIAL ENERGY CONSUMERS

Commercial Energy Consumers Association of British Columbia

Comments on the BC Hydro Draft Integrated Resource Plan (IRP) 2012

For the BC Hydro IRP Technical Advisory Committee

August 10, 2012

Table of Contents

1. Introduction

The Commercial Energy Consumers (CEC) Association of British Columbia has been representing a Commercial Sector perspective on BC Hydro regulatory proceedings and energy policy issues for over 10 years. With respect to the long term planning issues in the Draft Integrated Resource Plan (IRP) the CEC was involved extensively in the British Columbia Utility Commission (BCUC) review of the BC Hydro 2008 Long Term Resource Plan.

The following comments are provided to BC Hydro as part of the CEC participation as a member of the BC Hydro IRP Technical Advisory Committee (IRP TAC).

The CEC appreciates the opportunity BC Hydro has provided to the CEC to comment on the draft IRP as part of the IRP TAC.

2. Summary Views

The CEC believes that the IRP needs to be viewed in terms of its potential impacts on BC Hydro ratepayers and that this is an important perspective not well developed in the IRP. The CEC's estimates of these potential impacts form part of its views.

BC Hydro has summarized its recommendation for this IRP in table form[1] under the headings of its four key strategies Conserve More, Build & Reinvest More, Buy More and Prepare for Potentially Greater Demand.

- The 'conserve more strategy' results in a about a 10% increase in total conservation and efficiency.
- The 'build & reinvestment more' strategy results in about $10 billion of capital expenditure or about a 50% increase in BC Hydro's total balance sheet assets.
- The 'buy more' strategy results in commitments to about a 13% increase in total long term energy purchases.
- The 'prepare for potentially greater demand' strategy results in considering about a 150% increase in total long term energy purchases.

The CEC estimates that the first three strategies will result in about a 20% increase in BC Hydro rates on top of the annual rate increases of at least 5% per year and maybe more required to; deal with aging electrical infrastructure, keep up with customer growth, keep up with inflation

[1] IRP, Page 9-3, Table 9-1

in costs, engage in more sophisticated stakeholder relationships and provide revenues to government.

The CEC estimates the fourth strategy will result in considering supply impacts which if acquired would potentially add another 50% increase to rates on top of the preceding base rate increases and the 20% per year increases from the recommended strategies.

The CEC as a group representing ratepayer interests finds it useful to understand long term resource planning in terms of the potential rate impact on BC Hydro customers. The CEC believes that it would be useful to have such information in the IRP process and documentation, so we would urge BC Hydro to consider providing clearly the long term rate impact of its strategies and recommendations.

These rate impacts arise because as BC Hydro ratepayers we all enjoy prices for electricity which are substantially less than the cost of new supply. There is a balance to be found where new growth and existing customers receive strong price signals about their demands for power and the sharing of the benefits of the heritage legacy of low cost power. The CEC believes this is an important discussion not captured in the IRP planning process but which nevertheless is an inevitable consequence of the realities the IRP is attempting to address.

The CEC believes that BC Hydro's customers, BC Hydro and the Province will need a fifth strategy to Insulate More (IM). The clear story of the IRP from load forecast through to resource plans is the magnitude of impact the natural gas and LNG industry will have on British Columbia. The effects are like a shock and may require some degrees of insulation to avoid more severe consequences.

This fifth strategy needs to contain concepts like (1) a complete comprehensive review of the transmission service electric tariff (2) a comprehensive review of interconnection policy (3) an examination of potential zones for rate setting (4) an examination of cost allocation approaches (5) an examination of the BC energy objectives with appropriate tradeoffs and (6) a balance of resource option considerations between maintaining a competitive economy and moving toward more sustainable society futures.

The CEC recommends a discussion on this fifth strategy begin and that BC Hydro should consider devoting an IRP TAC meeting to the subject.

3. Key Issues Examination

3.1. Recent Policy Progress for BC Hydro Customers

The current British Columbia government has been making changes to the policy governing BC Hydro and the outcomes of the IRP planning process. These policy changes include the removal of water rental indexing to the BC Hydro rate increases, the allowance of planning based on average water conditions and the removal of the requirement to carry 3000 GWh/year of additional energy over and above the requirements to service the load demands of its customers. These policy changes have resulted in very significant future cost reductions for BC Hydro and consequently reductions of the projected rates BC Hydro's rate payers would otherwise have had to make. Without these policy changes BC Hydro ratepayers would have had rates at least 20% higher than they otherwise would have been. Some of these policies were part of the previous government's Clean Energy Act and the removal of these policy excesses has occurred during the period of time the IRP TAC has been reviewing the resource planning for BC. The CEC commented on these policy issues as part of its interim comments to the IRP TAC. The CEC believes that the IRP process has demonstrated that the government is listening and has shown the ability to greatly improve the prospects for BC Hydro ratepayers. The CEC believe that the government and BC Hydro should continue to evolve the policy framework and continue to mitigate the potential rate impact implications of this draft IRP.

3.2. Existing Power Supply Surplus

The existing levels of acquisition of power from independent power producers as a consequence of the 2009 Clean Power Call has resulted in BC Hydro having a significant surplus of energy. This surplus of energy is shown in the IRP planning documents and has been documented in BC Hydro's John Hart Generating Station Replacement Project application for a Certificate of Public Convenience and Necessity (CPCN). The Initial LNG facilities would require approximately 5300 GWh/year and 638 MW of capacity including losses on the transmission system to get the power to the plants[2]. The BC Hydro electric system would be required to maintain reserves of 14% in support of the required capacity as well. The surplus is short term until 2021 if the LNG facilities use natural gas generation supply[3]. The surplus is shown on the basis of average water and must be sold in the spot market but will be more or less than shown based on actual water flows in the BC Hydro system. The recent selling prices for power in the

[2] John Hart Generating Station Replacement CPCN Application, Exhibit B-1, Page 2-37
[3] John Hart Generating Station Replacement CPCN Application, Exhibit B-1, Tables 2-4 and Table 2-5

spot market were made available in the Dawson Creek Chetwynd Area Transmission (DCAT) Project application for a CPCN. The IRP forecast of electricity market prices starts at about $38/ MWh and rises to $57/MWh over the 20 year time frame[4]. The power purchased in the 2009 Clean Power Call was acquired for $124/MWh average. BC Hydro inflates this at 2% per year to reflect the cost of clean renewable energy in the future. Also to deliver this energy BC Hydro has had to acquire the capacity to deliver the energy which costs is based on the Revelstoke 6 unit expected cost of $55/KW-year. The losses incurred on the excess acquisition of power evaluated with these factors would amount to over $2 billion in nominal value and a Present Value of $1.7 billion. The CEC believes that it will be important not to repeat this acquisition of excess supplies of energy.

3.3. New Natural Gas for LNG Policy

The British Columbia government has a new LNG Policy with respect to providing power to the LNG facilities from natural gas generation, which the government has now designated as a clean resource for this purpose. The CEC commends the government for this policy change as it will be an important step toward insulating BC Hydro's customers from greater rate increases. The IRP TAC was not aware of this policy and has not had a chance to be informed of all the potential implication for the IRP. The IRP TAC has certainly been discussing the impact of the LNG loads and the potential for natural gas fired generation to contribute to reducing the rate impacts of serving these loads with expensive clean renewable energy. There is now a consequent need for a decision with respect to IRP planning with or without the LNG demand in the forecast. The potential for this policy change to add further benefit to the BC Hydro ratepayers is very significant given the magnitude of the load demand from the various LNG facility scenarios. Application to the initial LNG plant requirements would save ratepayers from an approximately 10% rate increase and for the future LNG plants it would save ratepayers from an additional 25% in rate increases. The IRP TAC has not had a chance to review this issue with BC Hydro as of the date of these comments. The CEC estimates that if the Initial LNG plants are served with natural gas fired generation supplied by the LNG export proponents themselves then the savings to BC Hydro ratepayers over a 30 year plant life versus service by BC Hydro with clean renewable energy would be over $10 billion in nominal value or a present value of over $3 billion. This is evaluated using the BC Hydro anticipated costs for clean renewable energy of $132 in 2012$ inflated at 2% as is BC Hydro's practice for estimating versus the transmission electric tariff rates applied to the same energy.

[4] IRP, Page 4-42, Table 4-12

3.4. Additional LNG Loads LNG3

The LNG load requirements may be augmented with another level of potential LNG export which has been characterized as LNG3 in the IRP. This shows an additional requirement of 6400 GWh/year by 2020 growing to 12800 GWh/year over the planning timeframe[5]. If this load were supplied by BC Hydro in the future with clean renewable energy it would have a cost to BC Hydro ratepayers of about $5 billion present value and result in about a 25% rate increase. In addition to this cost there would be a requirement to advance transmission projects into the North Coast area. These transmission requirements are not incorporated in the scenario planning other than to identify them.

3.5. Electrification for GHG Reduction

The IRP also contains a scenario for extensive GHG reductions through electrification. The low scenario aims to achieve a 30% reduction over 2008 levels by 2050 and the high reduction scenario aims to achieve an 80% reduction over 2008 levels by 2050. The electrification loads associated with these scenarios for 2031 are approximately 5000 GWh/year for the 30% reduction and about an additional 3500 GWh/year for the 80% scenario, all within the 20 year timeframe. The impacts in the following 20 years would be significantly greater. If this scenario were to develop the cost of new supply relative to the revenues BC Hydro would be collecting would likely become equivalent as the rate of increase in rates for the BC Hydro ratepayers may have caught up to the growth in the costs of new supply. The approximate costs of these scenarios combined could be in the range of $3 billion present value which may appear low relative to other issues but this is because the electrification takes place much farther out in the future and the discounting reduces the present value perspective on the costs. By 2041 the costs of this scenario continue to expand with significant associated rate increases.

3.6. Acquisition of Power from Independent Power Producer

The BC Hydro IRP recommendations include a plan to purchase an additional 2000 GWh/year of energy from independent power producers in another call for power. The in service date for this energy is forecast for 2017 and assumes that the Initial LNG plants are supplied with the

[5] IRP, Page 2-34, Figure 2-8

surplus power already on hand, which would then be used up by 2017. If BC is to supply power to the LNG plants then the obvious option in planning to supply this energy would be to acquire it from the market, which is forecast to have energy available at prices from $38/MWh to $57/MWh. This would be considerably less expensive than buying clean renewable energy supply from independent power producers at a cost of over $140/MWh. For this 2000 GWh of energy over the 20 year IRP plan the benefit to ratepayers would be a nominal savings of over 8 billion and a present value benefit of over $2 billion. BC Hydro is not able to plan energy acquisitions such as this because of the planning constraints in the Clean Energy Act and regulations. These constraints mandate BC Hydro to plan using the average water conditions for the Heritage Assets of the BC Hydro hydroelectric system. If the LNG plant power supply were to be provided by natural gas generation facilities and the access to market power were available to the LNG Plant power supply then whenever the natural gas had a higher value than the market energy the LNG Plant power supply could back off use of natural gas in favour of market supplied energy. This would ensure reliable supply for the Initial LNG plants and would enable them to optimize the values for their natural gas. A significant portion of this market energy comes from clean renewable sources in any event. The market supply of energy is frequently coming from excess supply in the US caused by government policy to require renewable energy in the utility portfolios as a standard. In addition BC Hydro has significant issues with regard to surplus energy at the time of the freshet season. The consequence of this is that market prices for surplus energy at the freshet time are significantly lower than average. Avoiding the cost of additional power purchases from independent power producers would save something in the order of a 7% rate increase for BC Hydro ratepayers.

3.7. Site C

The IRP also recommends completion of the Site C dam on the Peace River as a means of meeting future load growth. The Site C dam is expected to have a levelized unit cost of energy of about $95/MWh[6] in 2011$ at the point of connection and costs about $8 billion. The Site C dam is a much lower cost resource option than the independent power supplier energy. Over the life of the Site C dam versus the cost of energy supply from independent power producers the BC Hydro rate payers would save about $3 billion. The Site C dam can be evaluated against the costs of natural gas fired generation which is expected to cost about $80/MWh[7] in 2011$. This value is based on natural gas prices of $7.34/GJ a price well in excess of the current and near future expected cost of natural gas. Furthermore there are now opportunities to acquire natural gas supply for the long term to stabilize the price of natural gas. BC Hydro is not able to

[6] IRP, Page 3-37, Table 3-13
[7] IRP, Page 3-41, Table 3-15

propose these options because of the constraints applied in the Clean Energy Act. Over the a 30 year life of a natural gas fired power plant versus Site C the benefit to ratepayers would be about $700 million using the BC Hydro assumptions. This benefit would be augmented substantially if the natural gas fired generation was tied together with access to market energy and the BC Hydro surplus energy above the average water conditions. In this case the benefit to BC Hydro ratepayers would be in the order of $2.5 billion over a 30 year life of a plant. The plant life would likely be extended significantly because of a reduced need to operate the plant because of the availability of non-firm supply. Also this form of resource option would likely be very clean. The available BC Hydro non-firm energy above average water and including that available from independent power producers would all be clean energy and would amount to at least 35% of the supply. The market energy acquired would have a significant percentage of clean renewable energy which is surplus to utilities south of the border. BC Hydro would also have options to explore other more cost effective reductions of GHG emissions over time. Apart from not being able to plan for a natural gas fired generation BC Hydro is not able to plan to do very much of the above to mitigate GHGs with reduction options for the natural gas fired generation because of its planning constraints under the Clean Energy Act. Under the Clean Energy Act constraints BC Hydro is able to plan for only about 100 to 200 MW of natural gas fired generation.

3.8. Demand Side Management Savings

The BC Hydro treatment of Demand Side Management (DSM) options as they compare to supply side options has been quite interesting. The DSM options have the lowest cost of any of the resource options available to BC Hydro and are expected to be in the range of $39/MWh to $49/MWh[8]. These values are substantially lower when incorporating the non-energy benefits and the gas supply benefits. The DSM options also have a very significant potential to reduce the need for future additions of expensive new supply, including the potential to make further reductions of about 7000 GWh/year[9]. The BC Hydro IRP recommends that DSM options 4 and 5, which would provide the additional savings, be advanced and explored[10]. The IRP plan however, does not include any presumption of potential success but rather proposes to proceed with acquisition of new supply. For each 1000 GWh/year of failure to capture these opportunities BC Hydro ratepayers are disadvantaged by about $1 billion present value versus the costs of new clean renewable resources with an impact on rate payers of about 3%. The DSM resources are one of the cleanest ways to meet future needs. In and of themselves they

[8] IRP, Page 3-20, Table 3-4
[9] IRP, Page 3-18, Figure 3-1
[1010] IRP, Page 9-2, Table 9-1

substantially reduce BC Hydro's environmental footprint. To not presume any measure of success out of these potential measures is an unfortunate bias in the planning. The DSM options are put through a risk adjustment process in the planning which diminishes their potential value such that they do not become part of the plan. The risk adjustment process is intended to account for the considerable uncertainties associated with new DSM concepts. By way of contrast the supply side options do not receive any risk adjustment of the nature that the DSM options receive. Yet the supply side options represent the greatest risk to BC Hydro ratepayers and to the provincial economy. For instance the over acquisition of supply is already set to cost BC Hydro ratepayers about $2 billion versus more sensible options. This risk of over supply is not finished. The 2009 Clean Power Call is included in the BC Hydro IRP at 2428 GWh/year in 2017. The 2009 Clean Power Call resulted in 3266 GWh/Year of Energy Purchase Agreements (EPA) being signed[11]. BC Hydro at that time presumed a 30% attrition rate for the EPSs or essentially a 30% failure to complete. Consequently as of 2012 there is a risk that all of the EPAs will complete. This would potentially add another 838 GWh/year to BC Hydro's surplus and extend the surplus period from 2021 to 2022. The cost to ratepayers of all of the independent power producers proceeding would be about ½ billion in nominal losses and about a $300 million present value loss. The dangers of over acquisition of supply side resources dramatically exceed the costs consequences of over acquisition of demand side resources, which cost practically nothing if over supplied[12]. It would be a significant improvement if BC Hydro could provide more analysis of the supply side risks. The risks of undersupply of the DSM results are outlined in the risk analysis but this analysis is primarily done in terms of deliverability and is not placed in the context of the alternatives to ensure adequate delivery. DSM is inherently more flexible than supply side options and has the ability to be increased, over a reasonably short period of time, to the extent it is seen to be falling short. The costs for exercising this flexibility and increasing the DSM savings are rather modest by comparison to providing supply side resources. BC Hydro has a number of contingency options available to ensure security of supply. BC Hydro is required to meet 66% of its future load growth with DSM as a policy constraint. It has analyzed its plans against this objective and so long as the Initial LNG loads are self-served by natural gas fired self-generation BC Hydro will meet the criteria. If the Initial LNG loads are served by BC Hydro with clean renewable energy then BC Hydro projects that it will miss reaching the objective[13]. If BC Hydro stepped up its efforts to provide cost-effective DSM then it would need to deliver and additional 8% of load growth by 2021 or about 1300 GWh/year. BC Hydro's position in the IRP is that it cannot meet this objective and so it has chosen to prepare the plan outside of its legal requirements under the Clean Energy Act. The consequences of the IRP planning in regard to DSM is to fail to achieve the

[11] Clean Power Call Report, August 2010, Page 1
[12] IRP, Page 6-24, Table 6-5
[13] IRP, Page 6-25, Table 6-6

opportunities for ratepayers and the province and instead accept and recommend more costly options and more environmentally damaging options.

4. Review of the IRP

4.1. Chapter 1

BC Hydro's IRP is guided by the British Columbia Energy Objectives under the Clean Energy Act. These objectives in some cases set out aspirational goals with a widely variable means of testing results and in other cases set out hard numerical target constraints on BC Hydro's energy planning. Examples of the later are the requirement (1) for self-sufficiency by 2016 (2) DSM to reduce expected increases in demand by 66% by 2020 (3) generate 93% of electricity from clean or renewable resources. In addition to the BC Energy objectives BC Hydro must comply with special directions to the Utilities Commission. Examples of these are (1) Special Direction 10 requiring BC Hydro to achieve self-sufficiency by 2016 (2) Special Direction 2 requiring BC Hydro to not rely on the Burrard Thermal Plant for firm energy planning.

The use of the Burrard Thermal Generating Station is constrained. This issue has been set out in the CEA subsections 3(5), 6(2)(d) and 13.

The Burrard Thermal Generating Station has many useful attributes even when it is not generating much energy. The security of supply for backing up various conditions which may evolve makes this asset an important one not to disregard, particularly as it still has a long potential useful life remaining. Its 950 MW capability and 7000 GWh potential in addition to its ability to add VAR support and transmission reliability make it very valuable.

The CEC believe that its use and value can be improved with augmentation of the legal context for its use.

4.2. Chapter 2

BC Hydro includes in its load forecasts information regarding specific customer loads to reflect load reductions through customer attrition or failure to continue ongoing operations[14]. BC Hydro has had available to it sector analysis of the prospects for continued operation of the sector at the size currently forecast. It may be useful at some point to reference where for instance the pulp and paper sector is with regard to consolidation of operations and transformation in response to world markets. For instance it may be appropriate to point out as a matter of update information whether or not the 2011 load forecast expected the Tembec

[14] IRP, Page 2-3

mill in Chetwynd to continue operations. This and other load adjustments are worthy of note when setting the stage for the starting point of the base BC Hydro loads.

The generally understood nature of a synchronized slowdown of the World's economies would be expected to have a significant impact on BC electric loads at some point this year or next. It may be useful to give some discussion to this point. Generally BC Hydro in its load forecasting does not take economic recessions into account, however, as they occur and their effects are known then BC Hydro picks them up in its annual forecasting.

These economic situations in some parts of the economy may be offset by other parts of the economy such as the continued growth of requests for service in the Dawson Creek Chetwynd area. It may be useful to incorporate some review of the events occurring through this year.

As the IRP involves some near term decision making, which could be very sensitive to such economic shifts as the above items, the government may want BC Hydro's perspective on these issues as it approaches the end of the year and any decisions it may make. The BC Hydro load forecast for 2012 may be well under development by the time the IRP is through to being delivered.

The load forecast for the industrial sector, including the LNG loads and Mining loads are potentially subject to changes in world market supply and demand. The slowing of the world economies has put some downward pressure on commodity prices. BC Hydro may want to consider providing any relevant update to its forecasting assumptions, which it says are predicated on high prices.

BC Hydro includes planned resources in its estimates of existing, committed or planned resources. These include the Ruskin Upgrade Project and the John Hart Replacement Project[15]. Between these two projects they add additional energy to the BC Hydro system. As BC Hydro has a number of heritage facilities which may undergo upgrading over the 20 year planning timeframe it would be useful for BC Hydro to identify, which those may be and to what extent there may be increased supply capability to consider. It may be inappropriate to be acquiring new supply when the existing supply upgrades may produce lower cost supply. The exclusion of information because of some degrees of uncertainty is a potentially poor practice for informing decisions makers particularly where significant decisions may be expected to flow from the information supplied.

BC Hydro has approximately 1600 GWh/year average non-firm energy from independent power producers as of about 2017[16]. It would be useful to provide information with regard to the

[15] IRP, Page 2-13
[16] IRP, Page 2-20

degree to which this non-firm energy is correlated annually with the BC Hydro Heritage Assets non-firm energy. This additional BC generated average non-firm energy effectively means that the 4100/GWh/year non-firm allowance on the Heritage BC Hydro system is 2500 GWh/year of non BC based generation supply from markets upon which BC Hydro is relying for planning purposes. This leaves considerable opportunity for integrating the potential for use of market supply above the average water conditions for the BC Hydro Heritage hydroelectric system. Although this is not available to BC Hydro under the current legal framework it is nevertheless important information for informing policy decision makers.

BC Hydro would do well to include as a matter of regular course in its IRP the probability of exceedance information it maintains with respect to the Heritage Hydro system and its IPP supplies.

The Phase 1 Resources are included for 10,100 GWh/year post attrition. The Bioenergy Call 1 & 2 are included for a total of 1000 GWh/year post attrition. The BC Hydro Clean Power Call is shown as 2400 GWh/year of firm energy. This is post attrition estimates of 30%. The integrated Power Offer is included at 900 GWh/year post attrition. The AltaGas Projects are included for 700 GWh/year post attrition. The Waneta Expansion is incorporated for 195 GWh/year post attrition. It would be useful for BC Hydro to provide the information on attrition allowance and the actual attrition rates to date relative to the allowance. CEC is concerned that BC Hydro has a significant surplus of energy and believes if some of the signed EPAs complete and the attrition rate is overstated then the surplus energy could be even greater. It would be useful for decision makers to have the full picture with regard to BC Hydro's existing resources.

BC Hydro shows the Firm Energy Capability in 2017 for the Heritage Hydro Electric system to be 42397 GWh/year[17]. BC Hydro notes elsewhere that it has updated the Firm Energy Load Carrying Capability (FELCC) to 44300 GWh/year[18]. It would be useful for BC Hydro to explain the difference as this may create some confusion with respect to the correct numbers to be using.

The Regional Scenario analysis is a significant addition to BC Hydro's planning. The North Coast Load Resource Balance shows that the capacity to supply the Initial LNG and LNG3 loads is not available. It would be useful to provide the N-1 capacity and the N-0 capacity lines for these regional scenarios because this information can be useful to decision makers particularly where the standards of service policy questions arise. It would also be useful to augment this with the N-1 and N-0 capacities after the non-transmission upgrades.

The Fort Nelson/Horn River Basin Regional Load Balance shows electric demand over several decades. The graphic does not have the units for this demand and the graphic does not relate

[17] IRP, Page 2-29, Table 2-6
[18] IRP, Page 2-18

to the numbers in the discussion above. If the graphic is in GWh/year it may be useful to provide the axis units and potentially relate the discussion to the graphic.

4.3. Chapter 3

The economic development attributes are concerned with Provincial GDP contribution, employment and provincial government revenues[19]. These measures particularly if reflected over the planning horizon may not adequately show the impacts of electricity rate increase caused by the relevant projects. This can be a concern if decision makers are focused on construction job numbers but do not realize that the requirement to pay for the consequences of the projects have the effect of reducing future jobs and economic activity. The CEC believes that this set of metrics may need further development.

The discussion of DSM Options is a fairly static and segregated means of representing the DSM opportunities. It may be useful for BC Hydro to incorporate a description of the dynamic nature of the DSM activity, particularly reflecting the fact that for any given DSM measure the learning and improvement to the performance of the measure is ongoing and continuous. Poor practices and poor concepts are eliminated or modified until the measure is operating on better principles. Some understanding of this dynamic nature of the DSM undertakings would be useful to describe and useful to model. This is an important discussion because it leads to proof and assurance of cost-effectiveness as well as deliverability. It may also be useful to provide a description of the flexible nature of the DSM activity, particularly reflecting the fact that the construction of what is included in DSM measure can change from time to time with new information, new technologies and new tactics. This is particularly important because it means that DSM is robust and responsive able to replace a component with a new one and achieve the same or better results. Modeling this flexibility and the rate at which new opportunities arise and can be incorporated is important because it leads to the proof and assurance that a finite set of proven activity does not restrict the ability of the DSM options to find new solutions. The CEC believes that the concepts behind the DSM options are somewhat static and dependent upon the known measures as of the current time. The CEC believes that the past history of the Power Smart programs has demonstrated both the dynamic response and flexibility characteristics. The CEC believes that it is not only possible but highly likely over the next 20 years to achieve more than the recommended Option 3.

The inclusions of Option 4 & 5 concepts and the recommendations to advance them are very welcome developments and the CEC supports this direction. The CEC does not believe that

[19] IRP, Page 3-9, Table 3-3

ascribing these options essentially zero success in the 20 year time frame is reasonable or appropriate particularly if it leads to acquisition of more expensive supply side resources.

The BC Hydro expected expenditures for the DSM total resource costs are expected to jump significantly[20]. It may be useful for this graphic to explain for the vertical axis that these are annual resource investments. It may be useful to provide an additional graphic to show the BC Hydro expected expenditure requirements. Without providing both perspectives there may be a potential for a decision maker to misconstrue the context.

The amortization period for DSM costs has been extended to 15 years to reflect the persistence of the DSM programs. The CEC understands that many if not all of the DSM measures have an element of being integrated into transforming the market. As such it is not unreasonable to pose the connection between programs and codes and standards and eventual societal changes. This connection and linkage in the development and consolidation of the savings gains makes it very likely that the benefit period for all of the DSM activity is extending far beyond the period of particular projects, programs or tactical measures. The fact that the program expenditures at the start of a market transformation are larger per unit of savings achieved is supported by the much less expensive process of capturing the benefits in codes and standards later. It is more likely that the matching of costs and benefits over the entire transformation would be an appropriate representation of the economic reality.

Generation with natural gas appears to be a very low cost method of generation[21]. The use of a natural gas commodity price of $7.34/GJ appears to be a very high cost of gas. BC Hydro should consider incorporating a discussion of the fuel sourcing and potential cost options where a generation method is so heavily dependent upon the fuel.

BC Hydro has considered a number of emerging technology options and has noted that compressed air storage is an option[22]. This option is further discussed in the detail appendix and references the potential improve generator turbine efficiency by 40%[23]. The discussion could go further to discuss the development of advanced adiabatic compression with heat storage and return and perhaps more interestingly the development of isothermic compression. This later technology is expected to have about 92% efficiency and these compressed air technologies can be augmented with heat from other sources to obtain greater efficiencies. It is possible to plan for conducting the air compression separate from the power

[20] IRP, Page 3-19, Figure 3-3
[21] IRP, Page 3-41, Figure 3-15
[22] IRP, Page 3-62
[23] IRP, Appendix 3A1, Page 5-80

generation with compressed air storage, using spot market energy or non-firm BC energy from independent power producers and then running the expander portion of the turbine using natural gas heat and the compressed air to produce the power. The emissions reduction for this method could be in the range of 50% and the cost effectiveness could be quite significant. The CEC believes that the advent of utility scale electricity storage technologies is very important and that they will emerge in useful cost effective operation within the planning timeframe. The CEC believes that BC Hydro should extend its innovation activities into working with these compressed air technologies because of their potential strategic importance for the nature and characteristics of the BC Hydro system.

4.4. Chapter 4

The GHG forecast has a huge degree of uncertainty[24]. It also has such a range that it results in a weighting in the resource planning analysis, which obscures the implied scenarios and the planning process of examining the range of flexibility to respond to change. Further it avoids the policy examination of the appropriate levels for response over time, which is an important literature for a quality integrated resource planning process. BC Hydro has the integrated planning process being conducted within significant constraints and therefore is not adequately developing the appropriate tradeoff information for decision making.

The CEC believes that it would be a better approach to integrated resource planning to develop scenarios for future GHG views of the policy options and then examine the potential resource plans and options for each as well as the flexibility plans which may be needed in the future to move between scenarios as the future unfolds.

The Natural Gas price forecasts are particularly problematic showing a real price increase of close to 4% per year[25]. This does not appear to bear much relationship to the underlying cost of providing natural gas and recently understood availability of North American supply let alone world supply. The sources for the forecasting have been notoriously unable to forecast future prices for natural gas. Unfortunately the process of forecasting has consumed significant attention while the resource planning options for managing security of supply and certainty in pricing have not been adequately examined to give decision makers serious planning scenarios.

The CEC believes the resource planning would be much more robust if the process involved identifying scenarios for future natural gas prices and resource response options and the flexibility plans to transition from one place to another as the future unfolds.

[24] IRP, Page 4-17, Figure 4-3
[25] IRP, Page 4-24, Figure 4-6

The REC price forecasting is dramatically changed from where the integrated resource planning process started and now is showing flatter to declining price forecasts[26]. The discussion on the REC pricing is much more appropriate than the early information BC Hydro was working with. The capping[27] of the REC pricing seems appropriate for BC Hydro's analysis process. Again it would be better planning to develop scenarios for these futures and discuss the resource response options and the flexibility to move plans as the future unfolds.

The CEC believes that the REC prices have such considerable uncertainty that it would be best to understand possible scenarios and potential responses.

The Electricity Price forecasts are even more problematic than the Natural Gas price forecasts, with the mid forecast rising at over 6% per year real[28]. The underlying realities and cost structures are far more important for anticipating future pricing scenarios. The updated forecast for Scenario C shows a rise of 2.5% per year but the forecast BC Hydro is adopting from Ventyx is rising at over 7.5% real per year. As this forecast will drive the costs at which BC Hydro purchases some of its future energy it is an important factor and the BC Hydro forecasting does not appear to be particularly appropriate.

The CEC believes that it is imperative to examine different scenarios and potential resource option responses. The CEC believes that marginal costs of excess supply in the market from time to time will present opportunities for BC Hydro and that it is more important to anticipate the appropriate resource options and responses than to create weighted price scenarios.

BC Hydro with its predominantly hydroelectric system and very large storage capabilities is best operated in a net trading position with electricity markets and the self-sufficiency concepts represent constraints which undermine the potential values of the BC Hydro system.

Integrated resource planning is much more suitably conducted without constraint so that it can inform decision makers about options and the potential tradeoffs. The CEC believes that the entire price forecasting process can be improved and recommends that BC Hydro reexamine its price forecasting processes before doing its next IRP.

4.5. Chapter 5

The CEC believes that BC Hydro's integrated resource planning process of comparing alternatives using multiple objectives and the incorporation of the multiple attribute views of

[26] IRP, Page 4-29, Figure 4-8
[27] IRP, Page 4-33, Figure 4-9
[28] IRP, Page 4-36, Figure 4-11

its resource options is somewhat challenging to do but is a highly appropriate approach to integrated resource planning. The CEC is highly supportive of the BC hydro approach and believes BC Hydro has done well in its efforts to implement the methodology.

BC Hydro has identified a number of risks and uncertainties to be analyzed as part of its risk framework[29]. BC Hydro has not listed one of the most important risks related to integrated resource planning, being the risk of oversupply. This risk is one which BC Hydro has realized and is expecting to have as a feature of its system for some time to come. The risk developed out of a Gordian Knot of public policy and has direct financial consequences for BC Hydro's ratepayers. It would be quite useful to have this risk clearly analyzed. In contrast BC Hydro devotes numerous pages to examining DSM delivery risk. This imbalance appears to represent a supply side bias in the planning. The oversupply risk has put at risk the development of the Site C resource as a potentially more cost effective option than the independent power supply, which has been favoured.

The BC Hydro risk listing includes the risks with regard to regulation and public policy. These are critically important risks and in the past have represented key changes for which the resource planning has not been well prepared. This area could use a very significant discussion and analysis around a set of future scenario definitions. Unfortunately the integrated planning process proceeded with assumed constraints based on current policy. Constrained planning almost by definition limits the value which may be achieved from the planning process. In the future it would be useful to have a more robust analysis of policy options and have this information available for the key decision makers reviewing the plans.

Several important risks are listed including Site C delays, Burrard Thermal, Thermal Generation permitting, Transmission supply, and the features of the BC Hydro system. Unfortunately these risks do not receive any analysis. It is unfortunate that these and other key risk/uncertainty issues do not get some better analysis and discussion.

The load forecast uncertainty approaches particularly for residential loads and commercial loads is fairly well developed from long past experience. The approach to analyzing scenarios for significant binary reality large loads is particularly well done and the BC Hydro approach here is excellent. The CEC encourages BC Hydro to examine more scenarios in planning for the future.

The DSM savings uncertainty analysis suffers badly from flawed assumptions and from internal normalizing back to the known existing approaches. DSM is a very dynamic resource option. It involves continuous learning and improvement. It involves an ability to change pace in order to assure delivery. It involves the option to over deliver early to assure delivery later because it is

[29] IRP, Page 5-9

so cost-effective that it can be exported to electricity markets to pay for its development. It involves the ability to transform and mutate as new options develop and new tactics prove successful. It involves the ability to import concepts from others and the ability to invent new concepts as an ongoing process. This dynamism is not adequately modeled in the BC Hydro risk assessment and adjustment process. The consequence is a less than robust treatment of DSM. Even the implicit assumption in the process that the appropriate decision is to pick an option among the ones defined is flawed. This comes about because two of the options are simply levels of one another. The third attempts to resolve a failure of the other whereby they are too focused on the existing known planned and approved measures rather than the process over the long term of continuously developing options. The other two options however represent different approaches and if undertaken as scenarios they will begin to contribute savings and learn to develop their conceptual promise. To not model this into the integrated resource planning can lead to some poorly founded decision making. BC Hydro however is to be credited for recommending advancing these options to begin to develop them and thereby better understand what they may contribute in the future.

The CEC believes that BC Hydro needs a major revision of its DSM risk analysis and adjustment approach.

The recent government decision with respect to LNG plant power supply from 'clean natural gas' has provided an example of an uncertainty or risk, which was ruled out by planning constraints but has now become a realistic possibility with tremendously positive financial benefits for BC Hydro's customers.

The CEC needs to develop a better understanding of how this policy will be used because of its potential value to ratepayers.

The base case portfolio planning assumptions are explained as a set of uncertainties (gap size, market scenario prices, and binary loads), a set of resource choices (DSM, Site C and Thermal Generation), and modeling parameters (wind integration, and modeling horizon)[30].

The CEC believes that the planning assumptions might have benefited significantly from a set of uncertainties around policy constraints. This may have enabled BC Hydro to examine potential policy option scenarios and see how the resource portfolios may change for different futures.

The CEC believes that it would be useful to have among the resource options the choice to purchase more supply from the market, at least up to the equivalent of the BC provided downstream benefits, and to acquire the non-firm energy produced in BC for use in BC. The CEC believes that this in combination with natural gas plants serving as a backup capability and

[30] IRP, Page 5-45, Figure 5-9

source of reliability would provide more economic options. The CEC understands such options are excluded by government provided constraints.

The CEC believes that it would be useful to have different planning scenarios for the handling of integration with customers by examining different service products, transmission rates and interconnection policy. The CEC believes that it may be possible to avoid large cost increases for ratepayers while maintain useful service to customers.

4.6. Chapter 6

The Resource Planning Analysis examines (1) natural gas fired generation (2) demand side management measures (3) Site C (4) Incremental new loads in North Coast, Ft Nelson/Horn River & Electrification (5) General Electrification (6) Independent Power Producer supply, transmission and capacity.

4.6.1. Natural Gas Fired Generation

For natural gas fired generation the analysis focuses on a single parameter objective of 93% clean supply and BC Hydro rules out analysis of meeting such a target using import energy[31].

This is an unfortunate element of the analysis because information is not developed to show how much more cost effective such a small interpretation change for the objective would be. Worse still is the fact that the constraint has caused the resource planning analysis to fail to identify the potentially optimal uses of natural gas fired generation in the system and their potential cost saving attribute. It may well be that the cost of this GHG reduction limit produces extraordinarily high costs for GHG reduction and is not a cost-effective measure for this purpose in some cases.

The CEC believes that a quality IRP would analyze a number of sites and applications for natural gas fired generation and examine their cost effectiveness as well as their GHG profiles. BC Hydro found a $370 million saving by using natural gas within the 93% limit[32]. An interesting 'public interest' policy question would be how much more in savings versus the alternatives may be available throughout the electric system and what opportunities would there be to get more cost-effective GHG reductions elsewhere if the constraint was modified.

[31] IRP, Page 6-7
[32] IRP, Page 6-14, Table 6-3

BC Hydro's analysis shows that there is a significant potential to use natural gas fired generation for its capacity and dependability. This option has a relatively low cost of capacity at about $70-KW-yr although the market capacity, DSM capacity and Canadian Entitlement capacity are all lower cost options[33]. BC Hydro identifies at least four opportunities to avoid transmission expenditures through adding natural gas capacity plants and thereby saving over $2 billion[34].

The CEC believes that the use of natural gas units for their capacity value is appropriate and agrees that they can also provide an alternative to transmission capacity thereby providing additional savings. The CEC believes that one of the most important IRP planning criteria should be flexibility and that planning for and even permitting some such options in advance can assist BC Hydro in responding to need as it develops.

One of the most critical natural gas generation questions is whether or not the LNG loads and the natural gas production loads can be developed using natural gas and particularly whether or not the costs of serving natural gas export from BC can be economically covered by the export. The natural gas industry over the last 10 or 12 years has provided natural gas royalties and land bonuses of about $20 billion. The cost of providing electricity to the industry could involve BC Hydro rate payers returning much of the benefit paid by the industry when and if BC Hydro acquires and adds new high cost resource values into low embedded cost electricity rates. The consequent rate increase impacts of these large loads may require a 'public interest' discussion about what is appropriate. The IRP should inform such a discussion and the decision makers establishing the future policy.

4.6.2. Demand Side Management Measures

BC Hydro analyzes the DSM short term issues with respect to continuing to develop DSM savings while being in a surplus position and needing to sell surplus into the spot market. The regret analysis concludes that the down side risk is not as significant as the upside benefits particularly because the DSM is so inexpensive anyway[35].

The CEC not only agrees that DSM should not be ramped down but believes that in a period of surplus the emphasis for DSM should be on maintaining what is working and on developing new DSM capabilities for the future. In fact for this IRP it would appear that DSM should be ramped up even further to avoid the cost of acquiring expensive new independent power producer supply.

[33] IRP, Page 6-137, Table 6-32
[34] IRP, Page 6-17, Table 6-4
[35] IRP, Page 6-24, Table 6-5

The DSM impacts on the Load Resource Balance (LRB) show that with Initial LNG loads in the forecast the DSM plans included do not meet the target 66% of new load[36]. Without the LNG loads the DSM exceeds the target and begins to come close to being able to support a sustainable load growth for a long period of time. This becomes a repeating theme in the IRP that the LNG loads and electrification of the natural gas industry in the province will have staggering impacts on electricity prices and the BC economy. Unfortunately the scenarios shown in the IRP do not include the further extension of the industry beyond the Initial LNG and the LNG3 scenarios.

The CEC believes that it will be very important to decision making for this IRP and certainly for the next one for there to be a much more rigorous analysis of approaches to serving industry in general and the natural gas industry and LNG in particular. The CEC believes that the role of DSM in the LRB should continue to be strengthened because it is the best price, the best environmental profile and the most secure and certain route to a sustainable society.

The DSM cost effectiveness of all of the options shows gross TRC cost between $35/MWh and $50/MWh[37]. The DSM also shows significant value in regard to providing natural gas use reduction, non-energy benefits for customers and regional transmission and distribution capacity benefits.

The CEC believes this underscores the multiplicity of values that DSM provides beyond the base TRC cost test. The CEC believes that BC Hydro should continue to use the primary TRC test as its base for managing DSM but not lose sight of the array of added benefits DSM offers. Consequently the CEC believes that BC Hydro should be preparing to be able to significantly ramp up its DSM efforts for the future.

The BC Hydro analysis of the performance of DSM in its portfolios, the incremental cost analysis and the differential rate impact analysis show that it is highly beneficial to be pursuing further DSM particularly Options 4 & 5 to refine BC Hydro's understanding of how to ensure they are high savings options which can be developed and delivered with certainty.

The CEC believes it is critically important to develop new DSM options for the future and believes that investment in beginning to understand how to develop and deliver Options 4 & 5 is of paramount importance.

BC Hydro makes a point with regard to the deliverability risk related to DSM in doing planning and concludes that deliverability risk increases as there is greater reliance on DSM. The analysis is a simplistic proxy analysis.

[36] IRP, Page 6-25, Table 6-6
[37] IRP, Page 6-31, Figure 6-10

The CEC believes that DSM can easily be the least risky of all options up to and including when it is entirely being relied upon. This is because DSM can be pre-delivered before the need. The reason DSM can be pre-delivered is that it is so cost-effective that excess savings can be sold into the market and the costs can effectively be recovered until the excess savings are needed. The CEC also believes that DSM has significant flexibility to be driven to deliver performance with adequate investment. DSM initiatives can be developed and delivered to replace ones that fail for some reason. Certainty for DSM delivery is increasingly reliable as a diversification of concepts and agents for delivery are developed in the market place.

The CEC also believes that it is critical for government participation to evolve in the steps for developing Options 4 & 5. There will likely be key enabling steps for government to take to encourage and in part to undertake the development. Also there will be a need for significant public participation to develop a grass roots basis for these broader concept approaches to pursuing DSM.

The CEC believes that we are only at the beginning of the process for achieving additional benefits from the implementation of Smart Meters and a Smart Grid through the Smart Meter and Infrastructure (SMI) Project. The business case for this project has significant conservation and efficiency benefits in the first five years, which then diminish to a minimal base. The CEC believes that the Commercial Sector and others can work cooperatively with BC Hydro to define and develop additional DSM savings over the entire planning period.

4.6.3. Site C

The Site C Project is anticipated to be able to deliver 1100 MW and 4700 GWh of firm energy and 5100 of non-firm energy[38].

Site C is shown to be a cost effective resource relative to other clean renewable supply options[39].

The Site C impact on other objectives shows a significant foot print[40].

The CEC believes that Site C is a strategic resource option and cannot be strictly examined in the same context as other resource options. Hydroelectric resources are and have been the backbone of electricity supply in BC and they are responsible for an important heritage with its attendant long term low cost energy values for the BC economy. The long useful life of these

[38] IRP, Page 6-43
[39] IRP, Page 6-46, Table 6-8
[40] IRP, Page 6-50, Table 6-9

facilities and the fact that they are owned in the public interest are critical features, which the CEC believes can provide long term value to future BC Hydro ratepayers.

The CEC believes that the timing to an early in service date is not particularly critical and notes that the IRP expresses a potential for some delay because of various approval process requirements. Unfortunately the size of Site C and the magnitude of the capital costs will create a very significant rate impact as it comes into service. The CEC believes that there is some advantage to some delay in the timing of bringing Site C into service and that it will be useful to set up conditions that help to smooth out the rate impacts caused as the project costs begin to be allocated to revenue requirements from ratepayers.

4.6.4. Regional Scenario – North Coast

The North Coast has significant anticipated load growth from the Initial LNG loads of 5281 GWh/year and 680 MW of capacity[41]. There is a third LNG3 plant proposed which would be expected to start with a load of 6400 GWh/year and 800 MW and grow to 12800 GWh/year and 1700 MW[42].

The transmission system to the North Coast cannot provide for the Initial LNG loads without some significant upgrades. In addition the North Coast area has some significant mining load growth expected with the addition of the Northwest Transmission Line (NTL).

BC Hydro has looked at two options (1) supply from clean and renewable system energy on the existing transmission system with Single Cycle Gas Turbine (SCGT) back up supply (2) supply from the clean and renewable system energy over a new 500KV transmission line into the region[43].

BC Hydro expects to keep both these options open for more detailed examination and that the potential projects are on the critical path for development to meet anticipated customer deadlines[44].

The IRP has analysis of the rate impact for DSM for instance but does not for Site C or the North Coast.

The CEC believes that it is critical with regard to LNG loads to have further options including customer self-generation, potential zoning and a potential re-examination of the industrial

[41] IRP, Page 2-7
[42] IRP, Page 6-52 & 6-53
[43] IRP, Page 6-53 & 6-54 & 6-55
[44] IRP, Page 6-56

tariffs. The consequences of proceeding to providing supply, from the BC Hydro system, with the current embedded cost tariffs is a set of exceptionally high ratepayer impacts. This is particularly true for clean renewable supply but still has substantial effects if it is natural gas supply. It is very important for decision makers to be engaged in a discussion with respect to these impacts. The CEC believes the IRP does not sufficiently focus on these issues.

The CEC is concerned that regulatory fairness in rate setting requires rates that are not unduely discriminatory and as the natural gas industry including the LNG loads become serviced from the BC Hydro integrated system the potential for the rate impacts to mushroom could become unstoppable. At a minimum the decisions would be best made after due consideration of the many facts and issues which will be involved.

4.6.5. Regional Scenario - Fort Nelson/Horn River Basin

The Fort Nelson area and the Horn River Basin area are not tied into the BC Hydro electrical grid but Fort Nelson is connected to the Alberta grid. The Horn River Basin is primarily a load driven by natural gas production, while the Fort Nelson load is driven by a mix of residential, commercial and industrial load.

BC Hydro has identified three options (1) tying both Fort Nelson into the BC Hydro grid through transmission lines into the northeast of the province (2) establishing Fort Nelson and Horn River Basin as its own region and supplying the load from the region (3) establishing Fort Nelson as its own region and leaving Horn River Basin to self-supply[45].

The BC Hydro portfolio analysis shows that the options vary in cost-effectiveness depending on the size and magnitude of the load and the relative market costs for GHGs and natural gas[46]. The cost of reducing GHG also varies depending on the options and the market costs[47].

The CEC believes that the Fort Nelson/Horn River Basin area could be carved out into its own zone or perhaps two separate zones for electrical service. The CEC believes that eventually one Cogeneration Plant could be a good solution for the power supply if the loads develop. The CEC believes that it may even be appropriate to have the electrical service provided by a party other than BC Hydro in the region. The eventual loads in the area could become quite significant and the cost of interconnection to the BC Hydro grid would likely add significantly to the pressure on rates. The CEC believes that the addition of an SCGT for Fort Nelson may make sense. The

[45] IRP, Page 6-60 & 6-61
[46] IRP, Page 6-65, Table 6-16
[47] IRP, Page 6-70, Table 6-18

CEC believes that the questions of connection to the BC Hydro grid could be an issue for future consideration a long time in the future when there may be good economic value.

BC Hydro has examined risks related to development in the region and points out that there are consequences for planning for a load which may not materialize[48]. BC Hydro also points out that the loss of the cogeneration heat load would potentially be a large risk[49].

BC Hydro concludes that it should keep the options under study because the need is not clear and present requiring a decision.

The CEC believes that the decision on resource options may not be needed now but that the decisions on how to structure the service to the natural gas and LNG industries in the province does need to be made sooner rather than later to be fair to all players and to provide business certainty and context.

4.6.6. General Electrification

BC Hydro's studies of electrification being used to achieve GHG reductions to deep levels by 2050 show that they may be expected to lead to a 50% increase in electricity demand[50].

BC Hydro tested a model including the North Coast loads, including all LNG, the Northeast loads including Fort Nelson and the Horn River Basin and the General Electrification of the economy to reduce GHGs. The results showed that the cost of new supply rises from $130/MWh, $160/MWh and $200/MWh for 10, 20 and 30 years into the future[51]. In addition to Site C capacity there would be a need for an additional 12000 MW of capacity by 2041[52]. This would double the entire existing system capacity. In addition significant transmission investments are needed throughout the electrical system.

BC Hydro concludes that it should continue to study the options and the requirements for a strong GHG reduction policy and inform government.

The CEC believes that some of the information needed involves understanding the impacts on BC Hydro rates over this time horizon and the potential impacts on the economy. Using BC Hydro's information the CEC estimates the growth in rate increases is likely to be in the order of 3% to 4% per year continuously on top of the underlying rate increase requirements for

[48] IRP, Page 6-74 & 6-75
[49] IRP, Page 6-75
[50] IRP, Page 6-80
[51] IRP, Page 6-85
[52] IRP, Page 6-85

replacing and aging electric system, providing service to customer growth, keeping up with inflation and absorbing the government taxation requirements of an aging population. The CEC estimates this will likely push the annual rate increased for electricity into the range of 10% per year or higher. The BC Hydro rates would likely within the next 10 to 20 years increase to a level where they reflect the cost of new supply directly. There are already significant pressures on BC Hydro rates and this would see the rates double every 8 to 10 years until the rates themselves slowed the economic activity to a more sustainable level.

The IRP should be much more explicit about these impacts and deal up front with everyone about the costs of aggressive policy options and the potential context within which they will need to be managed.

The CEC believes that future IRPs could be improved significantly to deal with these issues among many other important issues not addressed directly.

4.6.7. IPP Acquisition Analysis

BC Hydro's base plans which include providing service to the North Coast Initial LNG plant shows a 3500 GWh/Year requirement for a few years before Site C comes into service followed by a period of balance for a number of years after Site C comes into service[53].

BC Hydro has done an analysis to determine how to address this short term issue. BC Hydro has analyzed what may be obtained from market reliance and has concluded that it could obtain 6500 GWh/year from the market[54]. This would result in an additional 2400 GWh/year of market energy reliance and would require another 1100 GWh/year from the market with some additional uncertainty. This approach provides a least cost option.

BC Hydro has provided analysis of the supply from independent power producers for about 2000 GWh/year, which when combined with an additional 1500 GWh/year of market energy would provide the high cost option[55].

BC Hydro has selected the high cost option for meeting the temporary need and thus following Site C would have a number of years of surplus energy needing to be sold into the spot markets at a loss.

The CEC believes that BC Hydro has not yet adequately discussed the potential for there to be a better solution to serving the North Coast Initial LNG than BC Hydro supplying the load. The CEC

[53] IRP, Page 6-89, Figure 6-19
[54] IRP, Page 6-90, Figure 6-90
[55] IRP, Page 6-90, Figure 6-91

believes that BC Hydro has not adequately explored the flexibility of DSM which could be ramped up to deliver the additional 1000 GWh/year by advancing what it is planning to do anyway by 1 or 2 years at the most. The CEC believes that BC Hydro has may be a bit to conservative and may be overestimating the constraints on its ability to purchase supply from the markets. The CEC believes that BC Hydro has not adequately explored the options for using SCGT back up for greater use of the market. The CEC believes that BC Hydro has not adequately looked at the use of the 1600 GWh/year average IPP non-firm clean renewable power produced in BC. The CEC believes that in the event of an emergency short fall the Burrard Thermal plant may well be able to provide the service. The CEC notes that the planning for IPP power is included in the plan expecting 30% attrition and to this point none of the IPPs has dropped out.

The CEC believes the purchase of more IPP supply, only to end up with it being surplus for a number of years, does not seem to make a lot of sense. The CEC believes the IRP is insufficiently robust when it comes to analyzing acquisition of new IPP supply.

In addition, to prepare for the future BC Hydro has adopted a plan to acquire another 10000 GWh/year of independent power producer supply[56]. This simply moves down the road of developing an electric system which is increasingly less competitive for the economy of the Province and expensive for BC Hydro rate payers.

4.6.8. Transmission

BC Hydro's analysis[57] of transmission requirements shows no new bulk transmission system requirements for the next 20 years. This assumes use of pumped storage in the Lower Mainland will be available. Non-wire reinforcements of the 500 KV transmission systems in the Peace and Columbia are required. The North Coast 500 KV radial transmission line requires reinforcement. BC Hydro has found that no additional requirements for the transmission system through to the end of a 30 year planning horizon are required.

Transmission contingency requirements have been analyzed for scenarios where (1) the load is greater than expected (2) the unavailability of pumped storage in the Lower Mainland, and (3) incremental North Coast natural gas or LNG loads[58].

Greater loads require reinforcement of the GM Shrum to Kelly Lake 500 KV transmission system.[59] Unavailability of pumped storage may require natural gas fired SCGTs at Kelly Lake

[56] IRP, Page 6-111
[57] IRP, Page 6-118
[58] IRP, Page 6-119 & 6-120
[59] IRP, Page 6-120

and additional transmission from Kelly Lake to the Lower Mainland and then reinforcement of the GMS to Kelly Lake 500 KV corridor[60]. For North Coast incremental loads new 500 KV lines are needed from Terrace to Kitimat and potentially from Prince George to Terrace[61].

The CEC believes that BC Hydro has done a reasonably good job of looking at the needed transmission requirements and the contingency requirements. The CEC generally believes that there are potential benefits available from working more closely with its customers to provide less capital intensive forms of service and mitigate some of its capacity planning problems. The CEC believes that BC Hydro would do well to incorporate into the IRP information about the duration curves for the load and options for mitigating the peak requirements as well as a discussion on the benefits.

Given the value of storage in deferring transmission requirements and making more intense use of the existing transmission system and the emerging technology options for storage the CEC believes that BC Hydro should have a robust program for looking at and pilot testing storage options in addition to pumped storage.

BC Hydro has a cluster analysis methodology for identifying the node requirements for integrating new loads and generation to the BC Hydro grid[62]. The multiple attribute analysis of the cluster approach has very similar impacts to the alternative bundle process[63]. The total costs for the cluster approach versus the bundle approach show significantly lower costs[64].

BC Hydro concludes that it has identified the appropriate cluster nodes but that no new transmission lines are required over the 20 to 30 year planning period. There are reinforcements required throughout the transmission system over the planning horizon.

The CEC believes that the transmission analysis has focused on appropriate responses to conditions identified and particularly believes that the Lower Mainland pumped storage and or Kelly Lake gas fired generation are important options to reduce costs. The CEC believes that the use of some local gas fired generation on the system would also be valuable. The CEC understands that there are constraints on the planning in legislation but the CEC believes analysis of the options is important to inform the policy process.

BC Hydro discusses the potential for pre-building transmission for generation and load and also the risks related to doing so. The CEC believes that there is a compromise between these issues. The main problem for transmission line construction is the length of time it takes to

[60] IRP, Page 6-120 & 6-121
[61] IRP, Page 6-121 & 6-122
[62] IRP, Page 6-124
[63] IRP, Page 6-126, Table 6-26
[64] IRP, Page 6-131, Table 6-31

build such lines and therefore the potential to slow down development. The CEC believes that advance routing and acquisition of rights of way as well as advance approval steps without actual pre-building may be useful in making the transmission responses more flexible and timely when the need is more proven and secure enough to justify building. The CEC would encourage BC Hydro to examine the potential for this form of building increased flexibility.

4.6.9. Capacity

BC Hydro shows its capacity requirements as about 1000 MW for a short term until Site C is in service and then a growth back from no requirement to about 1500 MW[65]. BC Hydro has an inventory of resource options for supplying capacity[66]. There are both short term emergency and bridging resource and well as longer term options.

BC Hydro discusses the uncertainties in the electric system and the nature of the responses and response time requirements that would be needed[67]. The need for Revelstoke 6 is shown with and without the Initial LNG Loads[68].

The CEC believes that having the Revelstoke 6 capacity will be a useful addition to the system.

BC Hydro identifies the short term bridging options as use of market for capacity backed up by the Canadian Entitlements (CE) and further backed up by Burrard[69].

The CEC believes that this combination of short term capacity is important to the system and believes the capability should continue to be a part of the planning as required. BC Hydro should be credited for providing this option as it is a cost effective solution.

BC Hydro also identifies 700 MW of SCGT natural gas fired plant in the North Coast as supporting future potential load.

The CEC believes that this could be appropriate if the loads materialize. More importantly this kind of capacity should be used to firm up greater reliance on the market for energy and on the availability of non-firm power from the IPPs as well as non-firm power above average water. The capacity not only has value in avoiding costs of transmission in the North but allows the BC Hydro system to make use of clean renewable energy produced in BC to reduce the

[65] IRP, Page 6-136, Figure 6-28
[66] IRP, Page 6-137, Table 6-32
[67] IRP, Page 6-142, Table 6-34
[68] IRP, Page 6-143, Figure 6-29 and Page 6-144, Figure 6-30
[69] IRP, Page 6-145

requirements for natural gas generation. The CEC believes that the 93% clean constraints could be reviewed with an objective of examining the potential tradeoff benefits of alternate policy.

BC Hydro analyzes the capacity requirements for larger demand requirement and for a smaller demand requirement and finds that for contingency purposes both the bridging and the natural gas capacity could be required but prefers to adopt the market, CE and Burrard bridging option because of its flexibility and because BC Hydro wants to preserve the option value of the natural gas capacity to defer transmission requirements[70].

BC Hydro analyzes its contingency requirements as being up to 2000 MW in the near term and 3000 MW in the longer term[71]. BC Hydro concludes that it needs to keep both pumped storage options and natural gas options in an inventory or resources to ensure that they can be built quickly if needed.

The CEC believes that it is appropriate for BC Hydro to invest in preparing for pumped storage and natural gas options including siting and pre-approvals to develop flexible response capability.

4.7. Chapter 7

BC Hydro has concluded that there is likely no opportunity for export of electricity at this time and plans not to pursue any while keeping a watching brief on the markets[72].

The CEC agrees with BC Hydro that there is little likelihood of direct export opportunities and agrees that BC Hydro should continue to monitor and watch these markets through Powerex.

4.8. Chapter 8

The BC Hydro consultation booklet for the public has some significant flaws which make the consultation of limited use.

Important questions are asked but no context is provided about the relative costs and tradeoffs one would consider important to answer such questions.

It is unfortunate to invest in public consultation with such a limited context.

[70] IRP, Page 6-154
[71] IRP, Page 6-158, Figure 6-40
[72] IRP, Page 7-14

The CEC believes that future IRP processes should provide a better level of context in its consultation and at a minimum should try to communicate the cost tradeoffs and the rate and or bill impacts associated with the strategies and actions being recommended.

4.9. Chapter 9

4.9.1. Strategy

BC Hydro has summarized its recommendation for this IRP in table form[73] under the headings of its four key strategies Conserve More, Build & Reinvest More, Buy More and Prepare for Potentially Greater Demand.

- The ‘conserve more strategy’ results in a about a 10% increase in total conservation and efficiency.
- The ‘build & reinvestment more’ strategy results in about $10 billion of capital expenditure or about a 50% increase in BC Hydro’s total balance sheet assets.
- The ‘buy more’ strategy results in commitments to about a 13% increase in total long term energy purchases.
- The ‘prepare for potentially greater demand’ strategy results in considering about a 150% increase in total long term energy purchases.

The CEC estimates that the first three strategies will result in about a 20% increase in BC Hydro rates on top of the annual rate increases of at least 5% per year required to; deal with aging electrical infrastructure, keep up with customer growth, keep up with inflation in costs, engage in more sophisticated stakeholder relationships and provide revenues to government.

The CEC estimates the fourth strategy will result in considering supply impacts which if acquired would potentially add another 50% increase to rates on top of the preceding base rate increases and the 20% per year increases from the recommended strategies.

The CEC as a group representing ratepayer interests finds it useful to understand long term resource planning in terms of the potential rate impact on BC Hydro customers. The CEC believes that it would be useful to have such information in the IRP process and document and

[73] IRP, Page 9-3, Table 9-1

would urge BC Hydro to consider providing clearly the long term rate impact of its strategies and recommendations.

These rate impacts arise because as BC Hydro ratepayers we all enjoy prices for electricity which are substantially less than the cost of new supply. There is a balance to be found where new growth and existing customers receive strong price signals about their demands for power and the sharing of the benefits of the heritage legacy of low cost power. The CEC believes this is an important discussion not captured in the IRP planning process but which nevertheless is an inevitable consequence of the realities the IRP is attempting to address.

The CEC believes that BC Hydro's customers, BC Hydro and the Province will need a fifth strategy to Insulate More (IM). The clear story of the IRP from load forecast through to resource plans is the magnitude of impact the natural gas and LNG industry will have on British Columbia. The effects are like a shock and may require some degrees of insulation to avoid more severe consequences.

This fifth strategy needs to contain concepts like (1) a complete comprehensive review of the transmission service electric tariff (2) a comprehensive review of interconnection policy (3) an examination of potential zones for rate setting (4) an examination of cost allocation approaches (5) an examination of the BC energy objectives with appropriate tradeoffs and (6) a balance of resource option considerations between maintaining a competitive economy and moving toward more sustainable society futures.

The CEC recommends a discussion on this fifth strategy begin and that BC Hydro should consider devoting an IRP TAC meeting to the subject.

4.9.2. Load Resource Balance Plans

The base load resource balance (LRB) plan for energy essentially shows Site C being built to accommodate the Initial LNG loads[74].

The future clean independent power producer acquisitions are not necessary because the requirements can be supplied by a combination of non-firm BC produced clean renewable energy, market reliance and DSM. This could be adequately secured with some level of natural gas plant as a backup.

It is possible that the Site C project may be delayed and the entire load requirement could continue for a long time to be met with this alternative strategy.

[74] IRP, Page 9-13, Figure 9-3

The use of the IM strategy could deliver a significant reorientation of the base LRB to mitigate rate impacts and ensure a competitive economy and supply to customers.

The CEC believes the base LRB for energy could be amended under the right circumstances to a much more cost-effective plan.

The base LRB plan for capacity shows Site C and Revelstoke 6 essentially supplying the new Initial LNG load requirements.

In the event that Site C is delayed the BC Hydro proposed bridging strategy could continue for some time.

If the energy strategy is shifted to using non-firm BC produced clean renewable energy, with market reliance and some additional DSM, backed up with some level of natural gas plant capacity the LRB for capacity could be satisfied until Site C or alternative resources were available and when appropriate to manage ratepayer impacts.

The CEC believes the base LRB for capacity could be amended under the right circumstances to a much more cost effective plan.

The CEC believes that a change in the base LRB plans could reduce future rate increases significantly and potentially by as much as 15%.

4.9.3. Contingency Plans

BC Hydro has identified a set of risks for shortfall from the base LRB for both energy and capacity[75]. BC Hydro then identified a set of contingency plan responses to the risk which then form a set of assumptions for which BC Hydro would then plan to be able to have the transmission capacity to deliver in the event of the risk being realized[76].

BC Hydro has created 3 contingency plans the core of which involves acquiring additional clean energy from independent power producers and providing natural gas capacity at Kelly Lake near the Lower Mainland load centre[77].

[75] IRP, Page 9-19, Table 9-7
[76] IRP, Page 9-20, Table 9-8
[77] IRP, Page 9-13 to Page 9-26

The CEC believes that the strategy BC Hydro has followed for the contingency resource planning is fundamentally sound and that BC Hydro should be preparing to be flexible and capable of fulfilling demand of this nature within reasonable response timeframes. Contingency planning of this degree will enable BC Hydro to assure secure supply of electricity for the province of BC for the planning horizon.

The analysis of the transmission requirements for the contingency plans indicates no bulk transmission is required and the CEC agrees with this conclusion.

4.10. Recommendations

4.10.1. Conserve more

Action 1: BC Hydro recommends pursuing DSM Option 3 for a savings target of 9800 GWh for 2021 and unit cost of energy of $10/MWh versus the cost of new clean renewable supply of $129/MWh[78].

The CEC supports this recommendation as far as it goes because it is highly cost effective and environmentally responsible.

The CEC believes it would be helpful to characterize the $180 million in bill reductions[79] for customers as to whether or not this is an annual bill reduction number or a total expected over the 20 year plan and possibly characterize the bill reduction in percentage terms for the average bill.

Action 2: BC Hydro recommends advancing DSM Options 4 & 5 but does not attach any savings to its efforts.

The CEC supports this recommendation but believes that it could be expected to be successful to some degree and could be expected to be associated with achieving some level of savings.

The CEC believes that the investment of this $7 million[80] will be critically valuable and the CEC would support even greater investment as the efforts progress and opportunities are identified.

[78] IRP, Page 9-28 & Page 9-29
[79] IRP, Page 9-29
[80] IRP, Page 9-33

The CEC believes it would be useful to identify the potential magnitude of the prize for a successful advancement of these strategies in the justification as a means of communicating the solid rationale for these expenditures.

Action 3: BC Hydro recommends pursuing DSM capacity options equivalent in size to the Revelstoke 6 project and estimated to be $32/KW-year and $53/KW-year[81] which would be quite valuable.

The CEC supports this recommendation as the potential is to provide this at significantly less cost than the future cost of capacity after Revelstoke 6.

The CEC believes that more of this kind of focused DSM activity will prove to be a significant improvement for the overall DSM efforts.

4.10.2. Build and Reinvest More

Action 4: BC Hydro recommends continuing to pursue the Site C project to add 5100 GWh/year of energy and 1100 MW of capacity[82].

The CEC supports a recommendation to continue to pursue the Site C project to improve BC Hydro's flexibility to construct and deliver such energy and capacity when appropriate as subject to the adoption of an IM strategy.

The CEC believes the Site C project is a strategic resource and is a cost-effective resource versus many of the alternatives.

The CEC believes that the Site C project may not be required at its earliest in service and would suggest BC Hydro keep as much flexibility following its approval processes to choose an appropriate implementation date in order to manage potential rate impacts relative to some less costly options which may be advantageously implemented before Site C.

Action 5: BC Hydro recommends developing the Revelstoke 6 unit for 477 MW of capacity and at a cost of $55/KW-year[83].

The CEC supports a recommendation to develop the Revelstoke 6 unit.

The CEC believes that the Revelstoke 6 unit is cost effective capacity and that it will be valuable to base LRB options.

[81] IRP, Page 9-35
[82] IRP, Page 9-37
[83] IRP, Page 9-43

Action 6: BC Hydro recommends using bridging capacity to manage near term requirements cost effectively. This involves using market reliance, the Canadian Entitlement and back-up from the Burrard Thermal generating Station.

The CEC supports the use of the bridging concept because it is expected to be highly cost effective versus other alternatives.

The CEC believes that this option is critically important to managing rate impacts from other more costly options. The CEC encourages the broadest possible authorization of the use of this flexible capability.

The CEC believes that the value of this option can be increased and encourages BC Hydro to seek at the appropriate time additional authorization to build the capacity and capability of this cost-effective option.

Action 7: BC Hydro recommends investigating and advancing additional Resource Smart projects.

The CEC supports the recommendation to pursue additional Resource Smart projects.

The CEC believes that the potential gains from Resource Smart projects are cost-effective and will make a valuable contribution to the resource plans.

The CEC believes that BC Hydro should identify potential costs related to these projects.

The CEC believes that the Resource Smart concept should be applicable to transmission and distribution systems as well as the generation system.

The CEC believes that there are potential voltage var optimization (VVO) options available and that it would be useful to reflect the potential for these in this action item.

The CEC believes that it would be useful to reflect an approximation of the potential for additional Resource Smart capital projects from its 20 year Generation Capital Plan and that BC hydro should be preparing a similar Transmission Capital Plan for the same purpose.

Action 8: BC Hydro recommends North Coast Transmission Upgrade for additional voltage support.

The CEC supports this recommendation because it is highly cost-effective capacity and the North Coast region has the potential for significant demand increases but believes that this support should be conditional on adoption of an IM strategy.

4.10.3. Buy More

Action 9: BC Hydro recommends development of 2000 GWh/year of additional clean energy

The CEC does not support this recommendation to acquire additional IPP power at this time.

The CEC believes that the procurement of this amount of energy is not needed at this time and that it is very expensive energy which may be surplus to BC Hydro's requirements.

The CEC believes that there are other more cost effective alternatives available to avoid the need to make the commitment to such purchases.

The CEC supports the broadening of the regulatory restriction relative to enabling use of non-firm energy from independent power producers in BC and on market reliance backed up by appropriate capacity.

Action 10: BC Hydro recommends exploration of pumped storage

The CEC supports this recommendation to explore pumped storage options.

The CEC believes it is prudent to examine these capacity options as they may at some point be required so the information from these explorations will be valuable for resource planning.

The CEC believes that BC Hydro should also be exploring a few other storage technologies as the CEC believes that the developments of potential for grid scale storage are likely going to provide transformational impact for utilities over the next 20 to 30 years. The CEC believes that investment in understanding the appropriate technologies will be very valuable to resource planning in the coming years.

4.10.4. Prepare for Potentially Greater Demand

Action 11: BC Hydro recommends new transmission infrastructure from the Peace River to the North Coast

The CEC supports this recommendation for new transmission lines subject to the adoption of an IM strategy and determination of the appropriate responsibilities for the costs of this planning.

The CEC believes that local gas fired generation options avoiding the transmission costs would be potentially more cost-effective and that the enabling changes should be considered in order to mitigate potential future rate increases.

Action 12: BC Hydro recommends development of future acquisition for LNG3

The CEC supports this recommendation for future supply for LNG3 subject to the adoption of an IM strategy and determination of the appropriate responsibilities for the costs of this procurement.

The CEC believes that these loads are so potentially large that the rate impact issues require different approaches to many aspects of servicing them and that the CEC proposed IM strategy insulation against substantial rate impacts is necessary.

Action 13: BC Hydro recommends natural gas fired generation backup to provide contingency capacity options.

The CEC supports preparing for and beginning the implementation of natural gas fired generation backup capacity capability to enable secure lower cost energy options.

The CEC believes that natural gas fired capability is likely to have very limited environmental consequences because it would be focused on providing capacity.

Action 14: BC Hydro recommends monitoring the Fort Nelson and Horn River Basin load and supply.

The CEC supports this recommendation to monitor the developments in the Fort Nelson and Horn River basin and encourages the development of an IM strategy to set out clearer expectations for the development of the natural gas industry in the region such that it will mitigate future potential rate impacts.

4.10.5. Additional Recommendations

Additional Recommendations 1: Province wide electrification studies for GHG reduction.

The CEC supports this recommendation for the purposes of understanding what may be done and what may be cost-effective in what timeframes.

The CEC believes that the GHG reduction issues will depend significantly on what happens in the rest of the world and that a judicious plan will be valuable, while avoiding excess will be critical.

Additional Recommendations 2: No investment in export market opportunities

The CEC supports this determination for the export market and continues to believe that the best export opportunities for BC electricity are in the products exported from BC.

Additional Recommendation 3: Pre-building transmission for generation clusters

The CEC supports continuing analysis of a cluster approach but does not support pre-building transmission and instead would support advance preparations such as routing and siting determinations along with right of way acquisitions.

The CEC believes that the risks involved with pre-building transmission are not supported by the potential benefits.

Additional Recommendation 4: Support development of geothermal potential

The CEC supports the development of the geothermal resource option because it is identified as a very cost effective resource opportunity.

The CEC believes the risks do not lend these resource potentials to IPP development so a new framework for encouraging access to these potentially low cost options will be warranted.

Conclusions

The draft IRP contains the elements of steps toward a future of 10% per year rate increase or more for BC Hydro customers. The CEC believes that alternatives to this future need to be examined and alternative policies reviewed for adoption.

To service all of the indicated future natural gas and LNG loads and the electrification loads with BC Hydro clean renewable energy would amount to putting the BC economic competitive advantage of low cost energy into one basket. The CEC believes that a negotiation and policy development are needed to develop an alternative future.

The CEC believes the draft IRP contains opportunities for reduction of future costs on the order of $1 billion per year through pursuing less constrained planning and by using alternative resource options and policies. The CEC believes that BC Hydro’s integrated resource planning should be facilitating the discussion with respect to the potential to capture these benefits.

WRITTEN SUBMISSION FROM:

THE PEMBINA INSTITUTE

August 10, 2012

Advice to BC Hydro Regarding the Draft Integrated Resource Plan

by Matt Horne | 604.874.8558 x 223 | matth@pembina.org

Overview

The Pembina Institute appreciates the opportunity to provide comments on the draft IRP. On balance, the efforts on BC Hydro's part to analyze options and make that analysis available to TAC participants have been commendable. We have grouped our recommendations under the following headings:

- Scenario planning
- Clean energy act objectives
- Conservation
- New supply
- TAC process

An overarching concern is that the major driver of new energy demand – liquefied natural gas (LNG) plants – has received limited analysis beyond the energy demand and economics, and minimal consideration by British Columbians. While there is a potential economic opportunity associated with LNG exports, there are also significant environmental impacts from the facilities and associated extraction and processing of raw natural gas. These include greenhouse gas emissions, water depletion, water contamination, and land fragmentation. The extent to which these facilities are in the overall provincial interest is unclear.

To our knowledge, the provincial government has not done the analysis or engagement to test how these costs and benefits compare at different scales of LNG export. Without this dialogue occurring, the ability of BC Hydro to move forward on its proposed actions will be diminished because there will be underlying questions about the rationale for the given actions. For example, it will be more challenging to develop social license for a project like Site C if the prevailing sentiment is that is being built to meet an electricity demand not deemed to be in B.C.'s interests.

Our recommendations suggest some ways to partially address these gaps by having BC Hydro play a constructive role in advancing public conversations about a broader set of possible future energy policy environments in its analysis. That said, it is paramount that the B.C. government also take a more proactive role in facilitating a dialogue with British Columbians about developments like LNG with such wide ranging and significant costs and benefits.

Scenario planning

1. **Explore changes to provincial energy policy:** In the same way that BC Hydro has made good efforts to assess a range of market factors in developing the IRP, we recommend adopting a planning approach that assesses a range of provincial energy and climate policies. We recognize that BC Hydro does not want to be perceived as undermining the provincial government's role to set policy, but we believe it is important for its responsibility in long term electrify planning to consider the outcomes of a range of possible policies. Given there were at least two major changes to provincial policy during the development of the IRP (self-sufficiency and LNG clean energy requirements), it seems prudent to ensure the robustness of the planning exercise and explore a range of potential futures.

   The recent change that eliminated the clean energy requirements for the energy demands of LNG facilities provides a good example of why it is problematic to produce plans with a static view of policy. The impact of that policy change is essentially to allow significant more natural gas-fired generation into the grid than would previously have been permitted and the implications of that change have not been explored in the draft IRP.

   In order to avoid a conflict with the province's roles and responsibilities, this additional scenario planning should focus on a range of plausible futures without attempting to apply probabilities to them. It would also likely be more successful if it avoided specific policy instruments and instead focused on the types of outcomes those policy shifts could drive. As an example, a possible variable would be the degree of regional environmental protection in the province, which would have general impacts of the costs and availability of new supply options. There would be many ways that provincial governments could influence regional environmental protection (e.g. environmental assessment, protected areas, environmental pricing/taxation, water use planning, etc.), but the specific policy tool would not be the focus of the IRP, just the implications for resource planning needs and options. Similarly, the IRP could explore other possible policy spaces based on factors like the degree of climate protection (i.e. preference for fossil-fuel energy versus low-carbon options), the priority placed on energy self-sufficiency versus regional grid reliance, etc.

   From this map of possible futures, the IRP would then focus on the current policy context and make plans that are commensurate with current priorities. However as these priorities shifts, there would remain a broader context to understand and prepare for the consequences of different policies.

2. **Develop and utilize better tools to help decision makers and the public understand the issues and tradeoffs:** The significant documentation for the IRP is an important part of the process that provides transparency for those with the ability to assess the details. While we support continuous improvement in this documentation, it is also important to acknowledge its limitations in reaching audiences that are not able to explore the material in significant detail. To

address this limitation, we recommend that BC Hydro develop and utilize interactive tools that make the issues being explored in the IRP more accessible to decision makers and public. Although the details of resource planning are undeniably complex, the economic, environmental and social tradeoffs can also be presented in a simple and intuitive manner that allows a broader audience to engage in the process more meaningfully. The Pacific Institute for Climate Solutions citizens engagement stream of research could be a useful local resource in exploring these types of communication and engagement tools.

Clean energy act objectives

While our previous recommendations support the idea of exploring alternative provincial energy policy futures, we recognize that BC Hydro has an obligation to comply with existing legislation.

3. **Provide overall assessments of performance against clean energy act objectives:** The executive summary of the IRP currently lists most of the clean energy act objectives, but it does not provide any assessment of how the IRP preforms against those objectives. Table 9-15 provides some of this assessment - in some cases assessing the IRP's performance against the objective, and in others assessing how individual actions relate to objectives without assessing if the net impact of actions is sufficient to meet the CEA objective. We recommend that all objectives be assessed at a IRP level (i.e. does the set of actions in the IRP as a whole meet the objective, in addition to an action level assessment if appropriate) and that a concise version of that assessment be included in the executive summary. For example, for the demand side management objective, a summary statement could say: "under the proposed actions, BC Hydro will exceed the clean energy act objective if no LNG plants proceed, but it will fail to achieve the objective in any scenario where LNG plants proceed."

4. **Communicate that B.C.'s GHG targets are likely to be missed under current provincial policy and the IRP actions:** Table 9-15 indicates how different actions will help the province reduce greenhouse gas emissions. While this is useful and relevant information, the draft IRP does not explain how well the province will be doing against its overall GHG targets in 2020 and slightly in advance of 2050. Responsibility for meeting those targets clearly falls to the provincial government, but from our perspective, BC Hydro has an opportunity and responsibility to go beyond presenting greenhouse gas reductions and help decision makers and the public understand what the IRP means for provincial greenhouse gas emissions.

   Based on analysis Pembina completed on the province's LNG strategy, it is almost certain that B.C. will miss its 2020 greenhouse gas reduction target based on current provincial policies and the actions in the IRP.[1] Adding up all of the

[1] Available at http://www.pembina.org/blog/611.

emissions from natural gas extraction and processing, and the LNG facilities, we estimated that B.C.'s natural gas sector stands to be responsible for 33 million tonnes of GHGs in 2020 — 75 per cent of the provincial quota. Without implementing much stronger policies the provincial government will be leaving the rest of economy with a small piece of the pie: only 11 million tonnes of the quota for the entire economy — an impossible cut of approximately 78 per cent from current levels in eight years.

These numbers don't account for the recent exemption of LNG demand from the clean energy requirements. Assuming that much of any LNG demand will be met with natural gas-fired generation as a result of the change, the resulting emissions will be several million tonnes higher. Given that the facilities will be operational into the 2040's and beyond, it is equally important to acknowledge the degree to which they would consume B.C.'s emissions quota as it approaches its legislated 2050 targets (11 million tonnes for the entire province).

We do not expect BC Hydro to figure out how B.C. is going to meet its greenhouse gas reduction targets, but we do think BC Hydro should be clear to decision makers that one of the consequences of the IRP is almost certainly to be B.C. missing its targets.

Conservation

There have been a number of encouraging shifts in the analysis and characterization of demand side management opportunities through the IRP process (e.g. the redevelopment of DSM option 5 and improvements to some of the language that characterized DSM in a negative light). These are on top of improvements from the last long-term acquisition planning process that did not look at DSM options more expensive than the cost of supply. We still see several areas in the draft IRP where conservation efforts could be improved, which are particularly important given the BC Hydro is not able to meet clean energy act's demand side management objective if LNG plants proceed.

5. **Accelerate timelines for DSM options 4 and 5:** We do not agree with the lack of urgency regarding the investigation and potential deployment of activities in DSM options 4 and 5, which wouldn't move forward until at least the next IRP is completed (potentially 2017). We support the staged approach, which dedicates resources to better understand both options, but the analysis and potential implementation should unfold on a faster timeline from our perspective. Of particular importance would be developing a contingency plan that allows resources to be allocated to implementation during the window between this IRP and the next should the analysis conclude that DSM options 4 and 5 represent good opportunities.

6. **Accelerate timelines for capacity DSM options:** Similarly to the previous recommendation, language on this in the draft IRP does not convey a sense of

urgency in the explorations of capacity focused DSM, which is incongruent with the fact that BC Hydro is projecting relatively near term capacity constraints.

7. **Clarify the degree of DSM uncertainty that the provincial government can influence:** The uncertainty analysis conducted on DSM options has been a useful exercise that appears to have helped reduce the potential of overestimating expected savings from DSM options. However, it is important to acknowledge that there are different types of uncertainty, some of which can be influenced or completely controlled by the provincial government. For example, whether or not the provincial government is going to pass regulations for new lighting standards is something that is uncertain from BC Hydro's perspective, but something that the B.C. government can see with relatively high certainty because they make the decision as to whether regulations will proceed or not. BC Hydro has not indicated how significant these 'controllable' sources of uncertainty are, and because all of the sources of uncertainty are lumped together, decision-makers are presented with a picture of uncertainty that is overstated. The presentation of the IRP should be revised to indicate the different types of uncertainty.

8. **Pursue DSM option 3 whether or not LNG proceeds:** Currently, a decision to pursue DSM option 3 is tied to a decision that LNG plants are moving ahead. We see three reasons to reject this approach: 1) there are opportunities to learn from the approaches in DSM option 3, 2) DSM option 3 is still a relatively low cost resource, and 3) there are non-financial costs (beyond GHGs) unaccounted for in supply projects under consideration. As such, pursuing this option immediately seems economically and environmentally prudent, and we recommend that BC Hydro include it in the base plan without being tied to specific LNG demands.

New supply

9. **Account for deliverability and cost uncertainty for supply projects:** The draft IRP continues to suffer from a relatively weak approach to characterizing uncertainty on supply side resources apart from an assumed attrition rate for new projects. This stands in stark contrast to the excellent effort to characterize and account for uncertainty in DSM options. The implications of this weakness are unclear, but based on the relatively significant implications of assessing uncertainty in efficiency and conservation options, it would be prudent to apply a similar approach to supply side options.

   All supply-side options will have uncertainties about costs that will impact their attractiveness relative to each other and to DSM options. Site specific projects such as Site C that are not easily replaced with alternatives will also have uncertainty relating to deliverability (i.e. can the project be developed) that are not assessed in the IRP. Taking Site C as an example, there is a probability that it will not be approved, there is a probability that it will take longer to develop than anticipated, and there is a probability that its cost will differ from the estimate currently presented in the IRP. From Pembina's perspective, these types of uncertainties seem material to the planning process in the same way that DSM uncertainties have proven to be. As such, they should be included in the analysis.

10. **Account for the impacts of climate change on new projects:** The draft IRP discusses climate change impacts for BC Hydro's existing system and the conclusion relayed in the draft IRP is the potential impacts are minor looking out to 2050. This may be a valid conclusion for the existing system - especially within the planning horizon, but the level of analysis is inadequate for new projects given those projects will be operational into the 2060s and 2070s and beyond when climate change impacts are expected to accelerate. For example, changing flows on the Peace river could positively or negatively impact the timing and availability of energy from Site C, and those types of impacts need to be accounted for in the analysis. We recommend accelerating the next steps in BC Hydro's climate change adaptation strategy with a focus on assessing the implications for Site C and figuring out how to account for climate change impacts on power projects where BC Hydro is not the proponent. The analysis should also be extended beyond hydro-electric projects to assess the potential implications for wind and biomass resources.

11. **Delay construction decision on Site C:** For several reasons, we feel a decision to move ahead with Site C continues to be premature. BC Hydro has clearly not addressed the concerns being expressed by Treaty 8 First Nations and until those concerns are substantively addressed, it is not clear how the project would have free, prior and informed consent from those communities. The conclusion that Site C is the cheapest supply option does not appear to be robust enough to justify a multi-billion expenditure. We recommend that BC Hydro re-evaluate the cost comparisons once the cost implications of the previous two recommendations are considered, along with any potential changes to the costs of wind in response to new estimates presented by the Canadian Wind Energy Association, and to the cost of Site C as a result of new information that emerges from the joint review panel.

12. **Expedite permitting for additional renewable energy projects:** We would not want a delay in Site C or other renewable energy projects to translate into increased pressure to build natural gas-fired generators in the province because they are deemed to be the only option that can be deployed quickly enough to meet demand. To mitigate against this risk and keep options open, we recommend moving ahead with permitting work for additional renewable energy generation projects such that they can be deployed on a faster timeline if needed. This would necessitate some sort of additional relationship with independent power producers that would reserve BC Hydro's right to access the power at a certain price, while also giving the producer the financial certainty to

move forward with the permitting steps in a project that aren't typically completed until an electricity purchase agreement is in place.

13. **Test approaches to better integrate non-financial factors into future IRPs:** The efforts to characterize environmental attributes in this IRP represent a notable improvement from past BC Hydro planning processes. They still leave much to be desired however, because although the characterization has become much more sophisticated, there is still limited ability to incorporate the information into the analysis in a material way. Making progress on this challenge should be a priority post-IRP approval so that possible approaches can be developed and reviewed prior to the start of the next IRP.

    One approach would be to estimate the non-financial costs for resource options in the same way that BC Hydro pioneered efforts to include GHG costs several years ago. Estimating other environmental costs is admittedly a challenge, but that is not a good reason to avoid the issue because by avoiding it, the current approach is akin to saying those environmental attributes (beyond GHGs) do not have a value, which is clearly not the case in reality.

TAC Process

The following three recommendations relate the TAC process itself and are for consideration for future IRPs or other BC Hydro planning processes.

14. **Increase the effort to find consensus within the TAC:** The TAC's terms of reference made space to actively explore possible areas of consensus, but this was not attempted through the process. While it is hard to predict if consensus would have been possible given the range of perspectives represented on the TAC, it would have been worth the effort to try. The potential value in this exercise is that BC Hydro may be able to find areas where there is explicit support (or opposition) across a range of interests and it allows those parties to directly seek compromises.

15. **Use an external facilitator:** While the BC Hydro staff tasked with facilitating the TAC did a good job, our perspective is that the overall process would be more effective with an external facilitator (an approach used by BC Hydro for other processes such as the EC&E committee). Given BC Hydro was also a participant in the discussions, a facilitator from an organization not affiliated with any of the participants would likely have helped advance the TAC discussions and improve the quality of advice to BC Hydro.

16. **Increase participant funding:** The participant funding made available to TAC members was adequate to prepare for meetings and participate in those meetings. Pembina appreciates this support, and encourage BC Hydro to continue making participant funding available for future processes. In the

interests of supporting well thought through advice from the TAC, we would also recommend that BC Hydro make additional participant funding available to acknowledge the time requirements involved in developing advice to BC Hydro outside of TAC meetings. There were four instances where BC Hydro solicited TAC input in addition to advice provided during meetings and funding was not available for these contributions.

WRITTEN SUBMISSION FROM:

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Comments on
BC Hydro's May 2012 Draft Integrated Resource Plan
By the BC Sustainable Energy Association

By Thomas Hackney, 10 August 2012

These are the comments of the BC Sustainable Energy Association (BCSEA) on BC Hydro's May 2012 Draft Integrated Resource Plan (Draft IRP). These comments are directed to BC Hydro's IRP Technical Advisory Committee (TAC), of which BCSEA is a member. It is understood that BC Hydro will produce a final IRP and submit it for approval to the BC Minister of Energy as required by the *Clean Energy Act* (CEA).

BCSEA commends BC Hydro and its staff for their diligent efforts to carry out the extensive and complex analyses needed to inform the IRP and their significant efforts to communicate this work to the TAC so that there could be meaningful engagement of stakeholders in the planning process. BCSEA believes that meaningful stakeholder engagement is necessary in order to achieve a robust and credible electricity plan for British Columbia.

Contents

I. Introduction

(a) BCSEA and Its Interests

BCSEA is a not-for-profit association of citizens, professionals and practitioners committed to promoting the understanding, development and adoption of sustainable energy, energy efficiency and energy conservation in British Columbia. BCSEA has eight chapters across BC and approximately six hundred and fifty individual and corporate members. Many of BCSEA's members are ratepayers of BC Hydro. BCSEA's goals include sustainable energy, energy efficiency and energy conservation in British Columbia.

BCSEA has intervened in numerous BC Utilities Commission proceedings related to BC Hydro's planning and revenue requirements, including the following:

- 2005 Resource Expenditure and Acquisition Plan,
- 2006 Integrated Electricity Plan and Long Term Acquisition Plan, and F2007-F2008 Revenue Requirements Application,
- 2008 Long Term Acquisition Plan,
- Inquiry into British Columbia's Long-Term Electridity Transmission Infrastructure ("section 5 inquiry", 2009),
- F2009-F2010 Revenue Requirements Application,
- F2011 Revenue Requirements Application, and
- F2012-14 Revenue Requirements Application and F2012-13 DSM Expenditure Schedule Application.

The interests of BCSEA in the IRP are as BC Hydro ratepayers and as advocates of the public interest in a cost-effective renewable electricity system. BCSEA's members want BC Hydro to promote conservation and efficiency and to acquire sustainable, low-carbon generation resources where needed for planning purposes.

In reviewing and commenting on BC Hydro's Draft IRP, BCSEA and its members emphasize the following three objectives:

- reducing GHG emissions and the wasteful use of resources by maximizing the achievement of cost-effective energy efficiency and conservation, and prioritizing the acquisition of these resources ahead of supply-side resources,
- reducing GHG emissions by avoiding the use of fossil fuel powered generation, and
- avoiding incentives to developments that increase GHG emissions or waste energy, by ensuring that such developments are exposed to appropriate price signals.

(b) Context

Several contextual elements are of particular interest to BCSEA with respect to the IRP:

1. A number of large industrial developments are proposed which would have profound effects of BC and BC Hydro's planning, through very large increases in greenhouse gas emissions and through very large demands potentially placed on BC Hydro for service.

2. Globally, the signs of climate change from human-caused greenhouse gas emissions are becoming clearer and more urgent. For example, North America has been experiencing record high temperatures this summer, and observations show that the Greenland ice sheet is melting more rapidly than previously thought.

3. With the recent cancellation of the review of BC Hydro's F2012-13 DSM Expenditure Schedule, the IRP has become the first opportunity since the 2008 LTAP to review BC Hydro's DSM plans. It emerges that BC Hydro proposes that, should some of the potential new electricity demand materialize, BC Hydro's DSM plan would not meet the energy objective of the Clean Energy Act that 66% of BC Hydro's new load should be met with demand-side measures.

(c) BCSEA's key points

1. GHG reductions

BC Hydro has a critical role in contributing to reductions in BC's GHG emissions and compliance with BC's legislated GHG reduction targets. BC Hydro should certainly avoid actions or planning decisions that would increase BC's GHG emissions. The legal requirement that BC Hydro's generation be "93% clean or renewable" should be regarded as an absolute minimum. BC Hydro should plan to exceed this minimum to the extent necessary for BC to meet its GHG reduction targets.

2. DSM

BCSEA concurs with BC Hydro's stated objective to target "all cost-effective and achievable DSM." However, BC Hydro's recommended DSM Option 3 falls short of this standard. In order to achieve "all cost-effective and achievable DSM," the IRP should plan to achieve 'Tier 1' savings from DSM programs of 2% of sales as recommended by John Plunkett of Green Energy Economics Group.

The Draft IRP fails to include a DSM plan sufficient to meet the statutory DSM objective (meeting 66% of load growth with DSM) in the event that "initial LNG" loads materialize. That is not acceptable, in BCSEA's view. The IRP should be revised to include plans to meet the statutory DSM objective in all reasonably foreseeable load forecast scenarios.

The 2007 Conservation Potential Review is out of date. BC Hydro should obtain a new conservation potential review, including an assessment of codes and standards and conservation rates.

BCSEA opposes the concept floated in the Draft IRP that if "initial LNG" load is delayed BC Hydro would revert to current DSM targets, i.e., lower than BC Hydro's recommended Option 3 targets. Simply put, BC Hydro should obtain all cost-effective and achievable conservation and efficiency savings.

In BCSEA's view, the Draft IRP exaggerates the risk of DSM shortfalls. Efficiency resources should be scaled up in the final IRP, based on confidence that BC Hydro can exert control over efficiency outcomes with aggressive marketing, financial, and implementation strategies employed by highest-performing efficiency portfolios elsewhere

BC Hydro should prioritize full characterization of codes and standards and rates measures, so that they can be included in BC Hydro's F2014 DSM expenditure schedule to be filed with the BC Utilities Commission.

BCSEA supports the recommendation in the Draft IRP that BC Hydro continue to seek cost-effective interruptible load opportunities with its customers.

3. Supply-side resources

BC Hydro's assessment of BC's wind resource appears to be out-dated. As a result BC Hydro's resource portfolio analyses may unduly discount the ability of clean and renewable IPP resources to cost-effectively meet the forecast load gap.

In BCSEA's view, BC Hydro must revise its portfolio analysis to reflect this new information and test the portfolio analysis conclusions, including that Site C should be pursued for its earliest in-service date.

II. Greenhouse Gas Emissions

(a) GHG policy issues

BCSEA strongly supports BC's GHG reduction goals, and we urge BC Hydro to do all it can in its planning and operations to further these goals. BC Hydro should plan as far as is practical to meet all the GHG reduction objectives and requirements, and it should give full weight to GHG reduction issues in its qualitative judgments on resource options.

The underlying reason for GHG reduction legislation and objectives is the urgent need for BC and all jurisdictions around the world to address the crisis of global climate change, which threatens to destabilize the world's climate systems, causing many harmful effects to ecosystems, species and human societies. It is critically important that BC should contribute its share toward reducing GHG emissions, and BC Hydro should be strongly proactive in supporting this imperative.

Parts of the Draft IRP carry with them large implications for greenhouse gas emissions in BC and for BC's legislated GHG reduction targets, particularly:

- "Initial LNG load," two proposed liquefied natural gas (LNG) plants in the Kitimat area that have requested service from BC Hydro and would require 4,935 GWh/y of energy for refrigeration and gas compression,[1]

- "LNG3," a possible further LNG plant that would require 12,800 GWh/y of energy,[2]
- Potential load in the Fort Nelson and Horn River Basin that is largely driven by expansion of the gas industry and the need for compression for gas,[3]
- Potential gas-fired generation additions to BC Hydro's system, either for peaking or for base load.[4]

Table 1 summarizes the magnitude of these potential GHG emissions relative to BC's total GHG emissions (as of the 2007 base year of the *Greenhouse Gas Reductions Target Act*[5]) and BC's GHG reduction goals under the *Act*. The potential GHG emission increases from actions related to the Draft IRP are large enough to affect, even overwhelm, BC's GHG reduction goals.

Table 1: Annual greenhouse gas emissions figures for comparison *

Item	**GHG emissions (tonnes/year CO_2 (equiv.))**
Initial LNG compression **	950,000
Initial LNG end use of throughput	15,000,000
LNG3 compression **	2,300,000
LNG3 end use of throughput	30,000,000
Powering Fort Nelson/Horn River Basin[6]	3,800,000 to 16,400,000
Fort Nelson/HRB end use of production[7] ***	25,000,000 to 216,000,000
Single cycle gas-fired peaker (100 MW) ****	200,000
Combined cycle gas-fired plant (250 MW)	2,000,000
British Columbia's 2007 GHG emissions[8]	59,400,000
BC's 2016 GHG reduction goal[9]	10,700,000
BC's 2020 GHG reduction goal	19,600,000
BC's 2050 GHG reduction goal	47,500,000

* Based on published project information or industry standards and standard conversions.

** Assuming combined cycle gas generation to power compression.

[1] Draft IRP, page 2-7.
[2] Draft IRP, page 2-8.
[3] Draft IRP, pp. 2-40 to 2-43.
[4] Draft IRP, page 6-7.
[5] *Greenhouse Gas Reduction Targets Act* [SBC 2007] c.42.
[6] Draft IRP, Table 6-13, page 6-58.
[7] Draft IRP, Table 6-16, page 6-67.
[8] *National Inventory Report, 1990 – 2010: Greenhouse Gas Sources and Sinks in Canada* (submission to the UN Framework Convention on Climate Change), page 69.
[9] *Greenhouse Gas Reduction Targets Act* [SBC 2007] c.42

*** Units are "PV of MT," apparently "present value of megatonnes" of CO_2 (equivalent), rather than annual emissions.

**** Assuming an 18% capacity factor.

The *Clean Energy Act* asserts significant goals relevant to BC Hydro's planning that are aimed at reducing greenhouse gas emissions, including:

- 2(c): the requirement to generate at least 93% of the electricity in BC from clean or renewable resources;
- 2(g): to reduce GHG emissions by amounts specified in the *Greenhouse Gas Reduction Targets Act,*
- 2(h): to encourage the switching of energy sources so as to decrease GHG emissions;
- 2(i): to encourage communities to reduce GHG emissions;
- 2(n): to export electricity so as to reduce GHG emissions outside of BC.

While government has made an exemption to the "93% clean or renewable" standard of section 2(c) for LNG compression,[10] it has not relaxed any of the other objectives.

BCSEA strongly supports maintaining the "93% clean or renewable" ceiling on fossil fuel generation, and we commend BC Hydro for its work to maintain it.

BC Hydro should go further: the "93% clean or renewable" standard should be considered a minimum, not a goal, and BC Hydro should avoid thinking in terms of the "optimal use of the 7 per cent non-clean headroom," as in section 6.2.7 (page 6-14).

BC Hydro should also give a higher weighting to GHG reduction in considering gas-fired generation intended to defer or avoid transmission reinforcement, as discussed in section 6.2.8 (page 6-20) of the Draft IRP.

Gas-fired generation should be considered as a last resort only, and it should be assessed in terms the need for such generation to have zero net GHG emissions, as per BC's 2007 Energy Plan.[11] The presence of the carbon tax should not be seen as removing this obligation.

(b) Potential LNG and natural gas production loads should not be subsidized

BCSEA says that any LNG plants or major new gas production loads requiring service from BC Hydro should not be subsidized by existing ratepayers; they should not have access to 'Heritage' electricity rates at below BC Hydro's cost of new supply.

BC Hydro has included two LNG facilities in its load forecast for the Draft IRP ("initial LNG") and addresses the potential for demand for service from further LNG operations, represented by "LNG3." However, the Government of BC is apparently discussing with at least some of the LNG proponents whether their plants would be powered by electricity supplied by BC Hydro or by self-generated electricity from gas ("On June 21, Premier Christy Clark announced that the province will allow LNG producers to generate gas-fired electricity to support their operations";

[10] Order in Council No. 572, July 24, 2012.
[11] *The BC Energy Plan*, 2007, Policy Action 18, page 39.

[12] and "The government has said the current hydro-electric grid will supply energy for two LNG plants, while the third plant will receive power from hydroelectric and natural gas sources and possibly wind power."[13]).

BC Hydro has also identified major new potential electricity loads, particularly from the production of natural gas in the Fort Nelson/Horn River Basin area.[14]

These potential loads would cause the need for major expansions or extensions of BC Hydro's transmission system and major expansions in generation requirements. If powered by electricity, in the best case, the LNG and gas production loads would seriously tax BC Hydro's ability to procure non-GHG emitting energy. In the worst case, they would force BC Hydro to procure gas-fired generation that would emit GHGs, compromising BC's GHG reduction targets and the low-GHG character of BC's electricity supply.

Gas production and LNG plants would also export large amounts of gas that, at its point of use, would emit volumes of GHGs in the order of 50% or more of BC's total GHG emissions. The BC government claims natural gas "is widely recognized as a transition fuel to a low carbon global economy … B.C. can make a significant contribution to global reduction targets when B.C. gas is exported to Asia as LNG and replaces coal and/or diesel as fuel for electricity production or transportation."[15] However, this is fundamentally challenged by Stephenson, Doukas and Shaw:[16]

> We find that the transition fuel argument for gas development in BC is unsubstantiated by the best available evidence. Emissions factors for shale gas and LNG remain poorly characterized and contested in the academic literature, and context-specific factors have significant impacts on the lifecycle emissions of shale gas but have not been evaluated. [abstract]
>
> …
>
> Nations across Asia and potential LNG export partners do rely heavily on coal for electricity generation, and in the best-case scenario, BC LNG could help reduce their dependence on coal.
>
> However, questions remain about whether LNG produced from unconventional gas can bridge to a sustainable energy supply, or will instead commit jurisdictions to technical lock-in of emissions-intensive energy infrastructure. [page 455]

Increased GHG emissions are not in the public interest, and BC Hydro's ratepayers should not be made to support them. Rather, any LNG plants and gas production should be exposed to the full cost of marginal power and any transmission extensions or reinforcements, as an appropriate price signal.

As well, BC Hydro faces large rate increases due to heavy costs of maintaining aging

[12] Vancouver Sun, 30 June 2012, Managing Our Bounty, Scott Simpson.
[13] The Canadian Press, 21 June 2012, B.C. Government to rename some natural gas 'clean' to keep green pledges, Tamsyn Burgmann.
[14] Draft IRP, section 6.6, pp. 6-59 to 6-79.
[15] *British Columbia's Natural Gas Strategy*, BC Ministry of Energy and Mines, 2012, page 11.
[16] *Greenwashing gas: Might a 'transition fuel' label legitimize carbon-intensive natural gas development?*, Stephenson, Doukas and Shaw, Energy Policy 46 (2012).

infrastructure, extending and reinforcing infrastructure and procuring new generation.[17] Absorbing additional costs for large, energy-intensive industrial development would be particularly inopportune for ratepayers. LNG plants and gas production loads represent extraordinarily large potential load additions which, by the tradition of sound utility management principles, can fairly be allocated to those causing the need for the additions.

(c) Any LNG and natural gas production loads should be electrified with zero-GHG energy

To minimize GHG emissions and the compromising of BC's GHG reduction goals, any LNG or natural gas production loads should be electrified, rather than being powered by natural gas. However, the GHG reduction purpose of this would be thwarted if the electricity that was supplied was generated by GHG-emitting generation. British Columbians are proud to have one of the cleanest sources of electricity in the world. They do not want to see that value compromised.

> ***Recommendation 1: BC Hydro should continue to maintain the "93% clean or renewable" standard in the IRP and, for any gas-fired generation included in the IRP, BC Hydro should take into account how that generation would affect BC's GHG reduction targets.***

III. Demand-Side Measures (DSM)

This section discusses:

- why BC Hydro should strive to increase its proposed DSM savings,
- why BCSEA says that it is realistic for BC Hydro to acquire 'Tier 1' DSM program annual cumulative savings of 2% of sales,
- how the DSM program savings described in the evidence of John Plunkett (filed in the review of BC Hydro's F2012-14 RRA) can be related numerically to the DSM savings proposed in the Draft IRP,
- uncertainties in adding program savings to those of codes and standards and conservation rates,
- why, based on the examples of leading DSM practitioners around North America, the 'Tier 1' savings goals are realistic,
- best practices for increasing DSM program savings,
- why increased DSM investment can be expected to lower, not raise, electricity bills,
- why DSM investment would be good for the BC economy,
- why BC Hydro should pursue all cost-effective DSM, even if the "Initial LNG" load does not materialize,
- why BCSEA says that BC Hydro is being overly cautious in its estimate of potential DSM savings, and
- BCSEA's recommendations for DSM Options 4 and 5 and interruptible load.

[17] See, for example BC Hydro's initial F2012-14 RRA application, Exhibit B-1, Executive Summary, page 2.

(a) Goals for DSM energy savings

BC Hydro says its approach to DSM in the Draft IRP is to "[target] all cost-effective and achievable DSM." [18] BCSEA concurs with this objective and commends BC Hydro for the work it has done since the 2008 LTAP to develop and implement effective DSM programs. However BCSEA believes that BC Hydro's recommended action to pursue DSM Option 3 (BC Hydro Recommendation 1) falls short of "all cost-effective and achievable DSM" and BC Hydro should go further.

BC Hydro acknowledges in the Draft IRP that, if the potential "initial LNG" loads in the 2011 Load Forecast[19] materialize, then Draft IRP would fail to achieve the objective in the *Clean Energy Act* (2(b)) "to take demand-side measures and to conserve energy, including the objective of the authority [BC Hydro] reducing its expected increase in demand for electricity by the year 2020 by at least 66%."[20] With DSM Option 3, 78% of new load would be met in the "without Initial LNG" scenario, but only 58% would be met in the "with Initial LNG" scenario.[21]

In BCSEA's view, it is not acceptable for the IRP to fail to include plans to meet the statutory DSM objective in all reasonably foreseeable load forecast scenarios. BC Hydro should not retreat from a government-mandated objective without first having made all reasonable efforts to achieve it. Some of the loads forecast in some of the contingency scenarios would legitimately challenge this energy objective, but not the "with Initial LNG" scenario. Based on Table 6-6 on page 6-25 of the IRP, the increase in demand for electricity would be about 17,000 GWh/y, of which 66% is about 11,200 GWh/y. As discussed below, this is readily achievable.

> ***Recommendation 2: BC Hydro should amend the Draft IRP so that the final IRP contains a firm plan to take demand-side measures to reduce its expected increase in demand for electricity by the year 2020 by at least 66%, to comply with BC energy objective 2(c). It is particularly important that the final IRP should meet the 66% objective even under the "with initial LNG" load scenario.***
>
> ***Recommendation 3: In the final IRP, BC Hydro should commit to achieving energy savings from DSM programs of 2% of BC Hydro's energy sales ('Tier 1' savings), while maintaining the 'Option 3' energy savings from codes and standards and conservation rates.***

BC Hydro should plan for and pursue 'Tier 1' energy savings, as described in the evidence of John Plunkett of Green Energy Economics Group (GEEG), filed by BCSEA and the Sierra Club of BC in BC Hydro's F2012-14 RRA and F2012-13 DSM Expenditure Schedule filing.[22] That is, BC Hydro should plan for and pursue annual DSM portfolio savings of 2% of sales per year (not counting trade sales).

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[18] Draft IRP, Table 1-1, page 1-12.
[19] E.g. Draft IRP Table 2-1, page 2-3.
[20] *Clean Energy Act* [SBC 2010] c. 22.
[21] Draft IRP, Table 6-6, page 6-25.
[22] Exhibit C-10-13, BC Hydro F2012-14 RRA, *Direct Testimony of John Plunkett on behalf of the British Columbia Sustainable Energy Association and the Sierra Club of Brisish Columbia* (attached as Appendix 1).

BC Hydro claims that, in pursuing Option 3, it is already pursuing all cost-effective programs: "For Option 3, programs are pushed to the limits of cost-effectiveness, defined as the point where marginal costs equal marginal benefits."[23] However, BC Hydro's risk framework analysis recognizes a range of possible DSM outcomes under Option 3, showing that the 'achievable' ceiling is not fixed.[24] Cost curve and detailed program incentive design data are not provided in the IRP, preventing assessment of BC Hydro's definition of "the limits of cost-effectiveness;" however, bundled TRC costs for DSM show little cost difference between Options 2 and 3,[25] and both options are far less costly than the marginal cost of new supply. This suggests that more cost-effective DSM program savings may be achievable.

According to Mr. Plunkett:

> … all indications are that BC Hydro could lower revenue requirements and rates by raising, not lowering the pace of cost-effective efficiency resource acquisition. BC Hydro's updated analysis [in the review of BC Hydro's F2012-14 RRA and F2012-13 section 44.2 DSM Expenditure Schedule] indicates that its planned level of DSM investment in F12/F13 is highly cost-effective for ratepayers (as measured by the utility test) and for the provincial economy (as measured by the Total Resource Cost (TRC) test) yielding benefits twice to three times the costs incurred. Its updated rate and bill analysis further shows that planned expenditures will lower average rates in the test period.
>
> I find no credible reason not to believe that acquiring more cost-effective efficiency resources than BC Hydro has proposed would further lower total costs of electric service, revenue requirements, and rates to BC Hydro's customers during the test period and beyond. On the contrary, there is ample evidence that BC Hydro could double the scale of savings it currently plans, at costs that, while higher than BC Hydro has experienced thus far, would still be highly cost-effective. I find that BC Hydro could do so by joining the top savings performance tier of North America's leading DSM portfolio administrators and using best industry practices for achieving higher participation rates and realize deeper cost-effective electricity savings among participants.
>
> I conclude that it is reasonable for BC Hydro to increase DSM program expenditures to ramp up annual portfolio savings by 0.5% of sales in F2013 and by another 0.5% of sales in F2014, producing total annual depths of savings from DSM programs of 1.5% in F2013 and 2.0% in F2014 and each year thereafter …[26]

Mr. Plunkett's evidence addresses the DSM plan BC Hydro presented in its F2012-13 section 44.2 DSM Expenditure Schedule filing as Option 2, an updated version of the DSM plan that BC Hydro advocated in its 2008 LTAP application.[27] Option 3, the DSM plan that BC Hydro now recommends for the IRP, "targets more electricity savings [than does Option 2] by expanding

[23] Draft IRP, section 3.3.1.3, page 3-14.
[24] Draft IRP, Table 5-9, page 5-21.
[25] Draft IRP, Table 3-4, page 3-20.
[26] Exhibit C-10-13, BC Hydro's F2012-14 RRA proceeding, *Direct Testimony of John Plunkett*, pp. 7 to 8.
[27] BC Hydro IRP Technical Advisory Committee Meeting #5 briefing materials, Slide 79.

program efforts, while keeping the level of activity and savings for codes and standards and conservation rate structures consistent with Option 2."[28] Option 3 comes closer to the goal Mr. Plunkett advocates, but still falls short.

Table 2: Comparative DSM savings plans, Energy (GWh/year, cumulative)

DSM Plan	**F2012**	**F2016**	**F2021**	**F2031**
A: BC Hydro RRA (Option 2) *	918	5,070	8,843	11,927
B: BC Hydro Draft IRP (Option 3) **	694	6,083	9,844	13,157
C: GEEG RRA, programs only ***	314	6,101	10,939	15,606
D: GEEG RRA, programs only + C&S + rates ****	909	9,579	15,052	21,019
E: BC Hydro RRA Load Displacement DSM *****	189	895	1,265	1,154
F: GEEG RRA, programs only + C&S + rates + L.D.	1,081	10,393	16,202	22,068
G: C minus B (rounded)	(400)	0	1,000	2,500
H: D (C&S & rates discounted 50%) minus B (rounded)	(100)	1,800	3,200	5,200
I: F (C&S & rates discounted 50%) minus B (rounded)	100	2,700	4,500	6,400

* From Exhibit B-1-3B, review of BC Hydro's F2012-14 RRA and F2012-13 s 44.2 Expenditure Schedule, Amended F12/F14 RRA – Amended New Appendix II, Attachment 2, Amended Table 1, *2012 Energy Load/Resource Balance*.

** From Draft IRP, Appendix 9B, Table 3, *BPR – Energy*.

*** From Exhibit C-10-13 of the review of BC Hydro's F2012-14 RRA and F2012-13 s 44.2 DSM Expenditure Schedule, Exhibit JJP-2, Appendix C, page C-4, *Cumulative Energy Savings Since F2008*, with the following adjustments (by T. Hackney): (a) base year adjustment made by adding a value for F2012 for programs only estimated from Ex. B-1-3B, Amended Attachment 5, Table 1; (b) line loss factor of 1.1 assumed. Does not include load displacement.

**** From *GEEG RRA DSM, programs only* (above), with values added (by T. Hackney) for "Rate Structures" and "Codes and Standards," taken from the Draft IRP, Appendix 9A, Table 1, except figures for F2012 and F2013, taken from Ex. B-1-3B, Attachment 5, Table 1. Does not include load displacement. Line loss factor of 1.1 assumed.

***** From Exhibit B-1-3B, review of BC Hydro's F2012-14 RRA and F2012-13 s 44.2 Expenditure Schedule, Amended F12/F14 RRA – Amended New Appendix II, Amended Attachment 5, Table 1, Load Displacement for Residential, Commercial and Industrial Sectors. Line loss factor of 1.1 assumed. (The Draft IRP does not provide a numeric break-out of DSM savings from load displacement as was provided in the F2012-14 RRA and F2012-13 s 44.2 DSM Expenditure Schedule filing, but load displacement forms part of the DSM savings BC Hydro lists under DSM programs.[29])

[28] Draft IRP, section 3.3.1.3, page 3-14.
[29] Draft IRP, Appendix 2B, sections 3.1, 4.1 and 5.1.

> Note: The base year adjustments should be seen as rough approximations and may not be methodologically accurate. For example, they may not properly reflect decay of savings.

Explanation: 'D' adds the DSM savings proposed by Mr. Plunkett ('C') with DSM savings proposed by BC Hydro in the Draft IRP for codes and standards and conservation rates. 'F' adds Mr. Plunkett's proposed DSM program savings to BC Hydro's DSM proposed savings for codes and standards, conservation rates and load displacement. 'G' compares the DSM savings proposed by BC Hydro to those proposed by Mr. Plunkett. 'H' adds Mr. Plunkett's proposed DSM savings to BC Hydro's proposed savings for codes and standards, and conservation rates; however, discounting the codes and standards and conservation rates savings by 50% as an assumed figure to account for possible overlaps with program savings. 'I' adds load displacement savings to 'H.'

The Draft IRP does not assess in detail how independent the energy savings from codes and standards and rate structures are from DSM program savings and hence potentially additive, but BC Hydro treats the relationship as additive, characterizing Option 3 as achieving the same savings from codes and standards and rates as Option 2 does, while increasing program savings.[30] Conversely, the change from Option 3 to Option 4 is characterized as retaining the program savings of Option 3, while increasing savings from codes and standards and conservation rates.[31] BC Hydro says its DSM programs are designed to "designed to capture additional DSM energy savings potential that remains beyond that obtained from codes and standards and rate structures," and to complement rate structures.[32] The DSM uncertainty analysis assumes DSM types are additive. [33]

Nevertheless, caution is advisable in adding program savings to those of codes and standards and conservation rates. As tabulated in Table 1, Mr. Plunkett's evidence shows that, with no reliance on codes, standards or rates, DSM savings could exceed those proposed by BC Hydro by 1,000 GWh/y by F2021 and by 2,500 GWh/y by F2031. Conservatively assuming that only half the savings from codes and standards and rates would be additive to program savings and adding savings from load displacement yields savings over BC Hydro's proposed savings of 2,700 GWh/y by F2016, 4,500 GWh/y by F2021 and 6,400 GWh/y by F2031.

Mr. Plunkett's evidence gives strong reasons to accept the 'Tier 1' 2% goal as realistic:

> Q: On what basis do you find that BC Hydro can cost-effectively increase its annual achievement of electric efficiency savings?
>
> A: My primary reason is that leading North American electric efficiency portfolio administrators have been and plan to continue saving two percent of total retail electric energy sales annually for half the long-run marginal costs of supply they avoid. BC Hydro could do likewise by following industry best practices in scaling up participation and savings and thereby increasing portfolio savings starting in F2012.

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[30] Draft IRP, section 3.3.1.3, page 3-14.
[31] Draft IRP, Appendix 3A-1, section 4.2.4.1, page 4-10.
[32] Draft IRP, Appendix 9A, page 9A-10.
[33] Draft IRP, Appendix 5B, page 5B-10.

> Q: What industry experience supports your finding that industry leaders have achieved or plan to achieve savings in the two-percent range?
>
> A: This experience is documented in a report prepared by GEEG for BCSEA-SCBC (*Electric Energy Efficiency Resource Acquisition Options for BC Hydro* dated April 17, 2012 and included as Exhibit JJP-2) It contains annual spending and savings by selected North American efficiency portfolio administrators going back as far as 2001 and in several jurisdictions future projections for up to 20 years. Exhibit JJP-2 provides information for electric DSM portfolios with the highest percentage of annual savings as well as others with lower savings. On the basis of results and plans of leading jurisdictions, it projects the annual expenditures BC Hydro would need to make to achieve annual savings equal to two percent of electric energy sales starting in F2013.[34]

In Exhibit JJP-2,[35] Mr. Plunkett surveys utility DSM plans and performances across North America, using data published by the American Council for an Energy-Efficient Economy (ACEEE) and the U.S. Energy Information Agency (EIA). The data include spending, reported DSM savings and DSM plans, covering years from 2006 to 2010. Plunkett compares DSM plans and savings to electricity sales, to yield a DSM percentage of sales figure, and he ranks utilities in a four-tier system, with 'Tier 1' representing utilities with DSM savings of 1.5% or greater of annual sales. Levelized costs of savings are plotted against depth of savings, and a regression model is used to analyze the data, leading to a calculation of the costs to BC Hydro of ramping up its DSM savings plans to the 'Tier 1' level. Mr. Plunkett concludes:

> … At an assumed average [DSM program] measure life of 15 years and a real discount rate of 5.5 percent, the unit cost of annual savings $0.22/kWh-yr translates to a levelized cost of $0.0219/kWh over the lifetime of the savings. ...
>
> Q: Is the levelized cost of saved energy directly comparable with the avoided marginal cost of energy supply?
>
> A: Yes. So levelized cost of $0.0219/kWh over the lifetime of the savings is well below the BC Hydro's estimate of avoided supply costs of $0.14268/kWh, making the demand-side resources it plans to acquire highly cost-effective.[6]
>
> [6] In 2011 dollars. Exhibit B-1-3B, Amended New Appendix II, Attachment 6, p. 191.[36]

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[34] Exhibit C-10-13, BC Hydro F2012-14 RRA proceeding, *Direct Testimony of John Plunkett*, pp. 12 to 13.

[35] Exhibit C-10-13, BC Hydro F2012-14 RRA proceeding, *Direct Testimony of John Plunkett*, Exhibit JJP-2, *Electric Energy Efficiency Resource Acquisition Options for BC Hydro*, by GEEG, April 17, 2011.

[36] Exhibit C-10-13, BC Hydro F2012-14 RRA proceeding, *Direct Testimony of John Plunkett*, pp. 11 to 12.

The *DSM Jurisdictional Review* that BC Hydro obtained from The Cadmus Group[37] confirms Mr. Plunkett's evidence on DSM savings potentials. The study considers recent DSM targets and achievements across North America. It assesses baseline date for 2009, identifying seven organizations with actual DSM savings in GEEG's 'Tier 1' category, including savings as high as 2.9% of sales.[38] To address annual variability of DSM savings, the study also assessed savings over a five-year period from 2005 to 2009, identifying five organizations in the 'Tier 1' category on an averaged basis (for some jurisdictions, DSM savings include costs and standards).[39] The study concludes by showing that the organizations considered exceeded their 2009 DSM performance goals by an average of 155%.[40] While the Cadmus Group study does not address cost directly, the large number of jurisdictions listed with high DSM savings targets implies broad acceptance of the cost-effectiveness of ambitious DSM plans.

(b) Strategies for acquiring additional cost-effective resources

Mr. Plunkett recommends a 'best practices' approach to maximizing DSM savings:

> Best practices in energy-efficiency resource procurement have been developed based on lessons learned from over twenty years of experience with program design and implementation throughout North America. These lessons have been distilled by Pacific Gas and Electric (PG&E) in collaboration with numerous electric and gas utilities. [footnote omitted] In my opinion, these lessons can be distilled into the following guiding principles for maximizing achievement of cost-effective efficiency resources in long-range electric and gas energy-efficiency resource planning:
>
> 1) Scale up portfolio electricity savings by choosing the pace, scale and target customer populations for discretionary efficiency resource investment that maximizes net economic benefits.
>
> 2) Avoid cream-skimming and the creation of lost opportunities by encouraging comprehensive treatment and deeper savings per participant.
>
> 3) Use uniform program designs across utilities and energy sources. This applies to BC Hydro and the customers it shares with Fortis gas, as well as to BC Hydro's programs in relation to those operated in neighboring territory by FortisBC electric.[41]

Mr. Plunkett's evidence describes these approaches in detail, and provides other examples and recommendations for maximizing DSM savings, including:

- Create uniformity of program design (pp. 40 – 41).
- Create deeper integration of DSM programs between BC Hydro and FortisBC's gas

[37] Draft IRP Appendix 5D, *DSM Jurisdiction Review – Comparison of DSM Achivements*, by The Cadmus Group, June 27, 2011.
[38] Draft IRP, Appendix 5D, Table 2, page. 6 (page 9 of 13).
[39] Ibid, Table 3, page 7 (page 10 of 13); and page 8 (page 11 of 13).
[40] Ibid, Table 4, page 10 (13 of 13).
[41] Exhibit C-10-13, BC Hydro F2012-14 RRA proceeding, *Direct Testimony of John Plunkett*, pp. 37 to 38.

service (pp. 41 – 44).

- Redesign BC Hydro's low-income retrofit program to incorporate best practices (p. 45).
- Adopt innovative financing for retrofits, including on-bill financing with a loan loss reserve (pp. 45 – 49).
- Carry out a street lighting conversion campaign (pp. 49 – 50).
- Accelerate efficiency investments in BC Hydro's own facilities (pp. 50 – 51).
- Carry out a new conservation potential review to capture current DSM research and analysis (p. 51).

Recommendation 4: BC Hydro should take immediate steps to obtain as soon as is practical a new conservation potential review to update the 2007 Conservation Potential Review, including an assessment of codes and standards and conservation rates.

(c) Rate and bill impacts of DSM initiatives

Fear of rate impacts should not deter from increased DSM investments and more ambitious goals. BC Hydro says that Option 3 would reduce ratepayer bills by $180 million over twenty years relative to Option 2, despite increased DSM investment and an increased rate impact.[42] Mr. Plunkett argues that increased DSM expenditures could actually lower rates:

> BC Hydro analyzed the impact on rates and bills of its proposed DSM investment in its amended DSM Plan. It found that compared to no additional DSM investment, its Plan for cost-effective efficiency investment would lower average rates over the 20-year planning horizon [BC Hydro Exh. B-1-3B, p. 65] Much of this favorable rate impact is due to amortization of DSM expenditures and recovery through rates over 15 years, which more closely matches the pattern of DSM cost recovery with the flow of benefit in terms of future utility system cost reductions from DSM investment. So long as increased efficiency investment is cost-effective under the utility test, it is reasonable to expect the higher level of DSM expenditures I recommend to lower average rates still further, at least for the F2013-14 test period.

On the last point, Mr. Plunkett notes:

> Another necessary condition for no adverse rate impact from additional DSM investment is long-run avoided marginal supply costs continue to exceed the marginal revenue losses from retail sales reductions due to electricity savings. This may not remain the case throughout the planning period; especially as inclining block rates based on long-run marginal costs are introduced to more BC Hydro customers.[43]

(d) Economic benefits of DSM investments

Increased DSM investments and avoided electricity costs would benefit the economy:

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[42] Draft IRP, Appendix 9A, section 3.1.2, page 9A-21.

[43] Exhibit C-10-13, BC Hydro F2012-14 RRA proceeding, *Direct Testimony of John Plunkett*, pp. 25 to 26.

> Acquiring energy efficiency resources equivalent to two percent of BC Hydro's total electricity sales so much more cheaply than supply will be a powerful stimulus to the economy the Company serves in the years ahead. The present worth of the net benefits from the efficiency portfolio investment over the next two decades is $13.7 billion using BC Hydro's avoided supply costs.[13] BC Hydro acknowledges that net resource cost savings from cost effective efficiency investment will multiply throughout the economy served by BC Hydro as households and businesses spend or invest the extra disposable income on other goods and services, increasing economic activity.[14]
>
> [13] Using a 5.5% nominal discount rate, and a long-run avoided costs of $142.68/MWh inflated to 2012 dollars (Assumptions from found in BC Hydro Exh. B-1-3B, p. 191).
>
> [14] BC Hydro Exh. B-1-3B, p. 66.[44]

(e) No reversion to "current DSM targets"

BC Hydro says, "If initial LNG is delayed, BC Hydro may consider reverting back to current [Option 2] DSM targets."[45] BCSEA opposes this concept.

Mr. Plunkett recommends as good planning practice:

> Like any utility seeking to minimize the total resource cost of supplying reliable electric service, BC Hydro should plan on acquiring all the cost-effective demand side resources that it can. The requirement that BC Hydro achieve 66 percent of future load growth should be considered a minimum, not a maximum target.[46]

And:

> Least-cost integrated resource planning principles dictate that monopoly energy utilities such as BC Hydro should plan and seek to acquire all demand-side resources achievable for less than the marginal costs of supply they avoid. As BC Hydro acknowledges, lowering savings levels in the test period reduces the capability to deliver higher savings in the future. Indeed, raising the pace of efficiency resource acquisition in F13/F14 increases the probability that BC Hydro will be capable of acquiring the higher savings that are likely to be needed in the future, especially if the risk of accelerated load growth materializes. Thus, I conclude that increasing DSM acquisition in the F2013-F2014 test period would lower the risk of having to acquire more expensive supply to meet greater resource deficits later.
>
> Accordingly, I recommend that the Commission authorize and direct BC Hydro to raise F2013-F2014 DSM budgets to as much as the $504 million that I estimate will be needed to achieve 1.5% and 2.0% savings in each year, respectively.

[44] Ibid, pp. 27 to 27.
[45] Draft IRP, note to Table 9-2, line 3, page 9-4.
[46] Exhibit C-10-13, BC Hydro F2012-14 RRA proceeding, *Direct Testimony of John Plunkett*, page 12.

> Toward that end, I also recommend that BC Hydro streamline, consolidate and strengthen the design and implementation of several of its current program offerings. The recommendations are based on my review of BC Hydro's amended DSM plan, the Commission's recent decision on the Fortis Energy Utilities ("FEU") DSM plan, and my own knowledge of current industry best practices.[47]

At a unit energy total resource cost of $44/MWh,[48] or an adjusted TRC of under $10/MWh with capacity, gas and non-energy benefits included,[49] or at a utility cost of $22/MWh,[50] DSM is less expensive by far than any of the other resource options available,[51] and less than the benchmark average cost of new supply of $129/MWh.[52]

(f) DSM delivery risk

BC Hydro devotes considerable effort to addressing the uncertainties of DSM, more so than for any other resource, addressing this issue in Appendix 2B, *Load Forecasting and Demand-Side Integration*, Appendix 3A-1, the *2010 Resource Options Report*, Appendix 5B, *Quantifying DSM Uncertainty*, Appendix 5D, *DSM Jurisdictional Review – Comparison of DSM Achievements*, Section 5.5.3.2 of the Draft IRP, *DSM Savings Uncertainty, and* Appendix 9A, *DSM Implementation Plan*.

BC Hydro applied conservative professional judgement to the analysis results to reduce further the risk of under-delivery of DSM, for example:

> Some of the extreme high levels of savings for Options 1, 2 and 3 were reduced, since such high levels of savings were judged implausible given that the tools and approaches in these options were similar to current practice.
>
> … The first three changes effectively lowered the expected value (average) of DSM Options 1, 2 and 3 …[53]

BCSEA says that BC Hydro is being overly cautious and 'leaving money on the table' with regard to DSM. BC Hydro takes a risk-averse approach to DSM:

> This jurisdictional assessment [by The Cadmus Group] was designed to assist in understanding the confidence with which BC Hydro can deliver its planned DSM savings in the coming years. <u>While this gives some reasons for cautious optimism about moving forward with DSM programs at the level of DSM Options 1 to 3</u>, it also highlights the uniqueness of BC Hydro's combination of all three DSM tools to achieve conservation targets. <u>This further underscores the value of testing out these new tactics in a low risk manner</u> to adequately harness their potential.[54] [underline added]

47 Ibid, pp. 8 to 9.
48 Draft IRP, Table 3-4, page 3-20.
49 Draft IRP, Figure 6-10, page 6-31.
50 Exhibit C-10-13, BC Hydro F2012-14 RRA proceeding, *Direct Testimony of John Plunkett*, page 12, line 3.
51 Draft IRP, Table 9-1, page 9-2.
52 Draft IRP, page 9-29.
53 Draft IRP, section 5.2.3.2.1, page 5-19.
54 Draft IRP, section 5.2.3.2.3, page 5-32.

BC Hydro has added a "risk adjustment" to its DSM proposed savings. While this is not fully described in the Draft IRP, an indication of its size is given by comparing Figure 3-1 of Chapter 3 (page 3-18) with Table 5-8 of Chapter 5 (page 5-21). For Option 3 DSM for F2021, Figure 3-1 shows energy savings of about 12,000 GWh/y (by visual inspection); whereas Table 5-8 shows a risk-adjusted amount of 10,266 GWh/y for the "average middle 60%."

Mr. Plunkett says:

> Q: What kinds of performance risks do energy-efficiency resources pose for BC Hydro and its customers?
>
> A: Like any resource, demand-side resources pose the risk that electricity savings will not materialize in the magnitudes at the times and at the acquisition costs that BC Hydro plans on. However, BC Hydro and other utilities consider DSM to be fundamentally different from supply because participation in DSM programs is voluntary and measures savings may not materialize or persist as projected. Whereas customers can choose whether to participate in BC Hydro programs or to install recommended measures, supply resources are dispatchable (either directly or by contract). To supply planners, a resource that depends on voluntary participation by thousands of customers looks much less dependable than supply.
>
> The risk that increasing demand-side resource acquisition will not deliver planned savings is easily overstated, however. Widespread underperformance or removal of efficiency technologies installed by efficiency programs is highly impractical and therefore improbable; there is no reason or evidence to suggest such behavior should be expected after higher market penetration of efficiency technologies due to scaled-up efficiency resource expenditures ...
>
> Q: Can't DSM program administrators exert substantial control over the level of program savings via changes in program strategies, such as financial incentives?
>
> A: Yes. In contrast with its inability to influence these forces determining electricity demand, BC Hydro can exercise significant control over the pace of efficiency resource acquisition. Lessons learned from industry leaders demonstrate that voluntary program participation can be counted on if portfolio administrators employ best practices in program design and implementation to maximize participation and participant savings.
>
> … Evidence abounds that stronger financial incentives and delivery methods are necessary to maximize the realization of cost-effective efficiency savings through increased market penetration of high-efficiency measures.
>
> Experience in Maryland, for example, shows that higher financial incentives for retrofit measures recommended by energy assessments through Baltimore Gas and Electric's (BG&E's) Home Performance with Energy Star (HPwES) (analogous to BC's LiveSmart) program led to increased measure installation. Potomac Electric Power Company's (PEPCO's) Shop Doctor Program in the 1990s offered free direct installation of cost-effective lighting retrofits and achieved participation rates over 80 percent.
>
> By contrast, requiring customers to put up two year's worth of estimated bill savings (as BC Hydro does in its commercial and industrial programs) poses an

> obstacle to participation, particularly in the present uncertain economy this economy, and therefore is associated with lower participation rates. …[55]

While BC Hydro recognizes ways in which it can mitigate the risk of DSM shortfalls, Mr. Plunkett says that Hydro's planning does not adequately reflect this:

> Q: Does BC Hydro recognize that it can reduce the risk of falling short of savings targets by strengthening financial incentives?
>
> A: Yes. In the discussion of managing the risks of DSM performance in its Amended DSM F12/F13 Expenditure Schedule Proposal, BC Hydro discusses steps it can take to improve the likelihood that programs achieve planned participation targets and that participants achieve planned savings. These include improving estimates of potential savings and strengthening program designs to increase participation and savings depth per participant. According to BC Hydro,
>
> > "To minimize the risk of lower participation than planned, DSM programs are designed to address barriers to energy efficiency and elicit customer participation using information from BC Hydro customers, trade allies and other jurisdictions. BC Hydro also undertakes comprehensive market and technical research into current and future DSM opportunities to develop the most effective Program Initiative designs. …
> >
> > Programs also face a risk of delivering lower savings per participant than planned. This risk is mitigated by using a variety of sources on unit savings to forecast overall program savings, including market research, technical reviews of projects, M&V, and program evaluations.
> >
> > If DSM program electricity savings fall below plan, BC Hydro can modify the program to respond and increase participation, for example by:
> >
> > • Increasing or modifying program advertising;
> >
> > • Modifying the program application process or eligibility criteria;
> >
> > • Increasing or modifying program incentives; and
> >
> > • Revising the list of qualifying products."[Exh. B-1-3B, Page 94 of 271, Amended New F12/F14 RRA - Appendix II F12/F13 DSM Expenditures Chapter 4 - DSM Performance Management, Page II-4-14]
>
> Q: In your opinion, has BC Hydro adequately reflected its ability to manage DSM risks in its decision to curtail energy-efficiency investment in its DSM Proposal?
>
> A: No. BC Hydro's reluctance to scale up efficiency resource acquisition appears not to fully appreciate the high degree of control it can exert over these variables with aggressive marketing, financial, and implementation strategies employed by highest-performing efficiency portfolios elsewhere..[56]

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[55] Exhibit C-10-13, BC Hydro F2012-14 RRA proceeding, *Direct Testimony of John Plunkett*, pp. 28 to 30.
[56] Ibid, pp. 28 to 30.

(g) DSM Options 4 and 5

BC Hydro has done commendable work toward developing DSM Options 4 and 5, which emphasize increased savings through 'codes and standards' and conservation oriented rate structures. BCSEA supports BC Hydro's recommendation to advance DSM Options 4 and 5."[57]

Maximizing DSM through codes and standards and rates is an appropriate supplement to DSM programs. It accords with BC's energy objectives set out in the *Clean Energy Act*. It also accords with BC's broader goals articulated in the Pacific Coast Collaborative's "2012 West Coast Action Plan on Jobs," in which British Columbia is a participant. The government has signalled its support for this approach by advancing Bill 32, the *Energy and Water Efficiency Act*, in the BC Legislature.[58]

BC Hydro says that the details of the Options 4 and 5 'codes and standards' and rates measures are not yet sufficiently developed. [59] In BCSEA's view, BC Hydro should prioritize full characterization of codes and standards and rates measures, so that they can be included in BC Hydro's F2014 DSM expenditure schedule to be filed with the BC Utilities Commission.

> ***Recommendation 5: BC Hydro should take steps to ensure that its next DSM plan and expenditure schedule to be filed with the BCUC under the* Utilities Commission Act *presents 'codes and standards' and 'rates' measures that are characterized sufficiently to be implemented.***

(h) Interruptible Load

BCSEA supports the recommendation in the Draft IRP that BC Hydro continue to seek cost-effective interruptible load opportunities with its customers.

IV. Resource Options Report – Wind Power

BCSEA is concerned that the Draft IRP assesses resource portfolios based on out-dated, overly high estimates of the cost of wind generation in BC.

The Draft IRP provides cost estimates for wind generation based on the 2010 Resource Options Report (2010 ROR). The 2010 ROR indicates that only about 2,000 GWh/y of wind generation is achievable for $100/MWh or less.[60] However, a May 2012 report by GL Garrad Hassan[61] prepared for the Canadian Wind Energy Association (CanWEA) estimates 20,000 GWh/y of onshore wind is potentially available at a cost of $100/MWh or less, at a P50 level. This would be some ten times the potential reported in the 2010 ROR.

The Garrad Hassan report identifies reasons for the newer, lower cost estimates, including:

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[57] Recommended Action 2, Draft IRP, Table 9-1, page 9-2.
[58] Draft IRP, Appendix 9A, page 9A-16.
[59] Draft IRP, section 9.4.1.1, page 9-29.
[60] Draft IRP, Appendix 3A-1, *2010 Resource Options Report*, Figure 5-6, page 5-29.
[61] *Assessment of the Estimated Costs of Wind Energy in British Columbia*, GL Garrad Hassan Canada, Inc., 24 May 2012. The Garrad Hassan report was circulated by email to BC Hydro and the TAC members and observers, under cover letter from CanWEA, on 5 July 2012.

- significantly higher energy production due to higher efficiency turbine models at the majority of the 121 sites, compare to values used in the 2010 ROR,[62] and
- significantly reduced costs for turbines from European and North American wind turbine manufacturers.[63]

Regarding decreasing turbine costs, the Garrad Hassan report states:

> Costs for turbines from European and North American wind turbine manufacturers are estimated to have decreased by approximately 20% over the last two years due to changing market conditions and turbine supply. The reported costs in this study are in line with the March 2012 Bloomberg estimate of a turbine cost per MW of $1.21M, which is 4% lower from six months earlier [7].[64]

The 2012 Garrad Hassan report is credible. GL Garrad Hassan Canada, Inc. is a reputable firm, familiar with BC's wind energy potential, and indeed, sometimes retained by BC Hydro to provide technical input to its wind resource assessments.[65] That said, Garrad Hassan says the cost ranges are high-level and "should be treated as indicative only pending a more detailed review of the sites considered."[66] Also, interconnection costs are excluded from the study;[67] and it is not confirmed that the study is 'apples to apples' with BC Hydro's ROR.

Nevertheless, the 2012 Garrad Hassan report gives strong evidence that BC Hydro's 2010 ROR needs to be updated, particularly in light of assumed higher efficiency turbine models and decreased turbine costs in the past two years.

> ***Recommendation 6: In the final IRP, BC Hydro should include the analysis of the GL Garrad Hassan report,* Assessment of the Estimated Costs of Wind Energy in British Columbia, *May 2012, and an updated assessment of BC's onshore wind resource potential.***

V. Resource Planning Analysis and Resource Plans

(a) IPP Acquisition Analysis

The new Garrad Hassan information on BC's wind resource concludes that a very large volume of on-shore wind energy is potentially available at or below $100/MWh. This makes wind dramatically more competitive with many of BC's other energy resource options, including Site C and gas-fired generation,[68] two resources that have a critical influence on the Resource Planning Analysis, as well as biomass, coal-fired power, etc. This should significantly change

[62] Ibid, page 18.
[63] Ibid, page 12.
[64] Ibid, page 12.
[65] For example, IRP, Appendix 3A-26, *Updated Capital and O&M Cost Assumptions for Wind Power Development in British Columbia*, GL Garrad Hassan Canada, Inc., 2010.
[66] *Assessment of the Estimated Costs of Wind Energy in British Columbia*, GL Garrad Hassan Canada, Inc., 24 May 2012, prepared for Canadian Wind Energy Association, page 1.
[67] Ibid, page 15.
[68] Draft IRP, Table 3-23, page 3-53.

the outcomes of BC Hydro's modeled portfolios, to the advantage of portfolios with wind power. The comparison of Site C portfolios versus non-Site C portfolios shows a $222 million or 2.5% PV advantage to Site C.[69] This could well be overturned by the new wind data. For example, it may be possible or desirable to defer Site C and instead make a larger call for power than presently proposed.

> ***Recommendation 7: In the final IRP, BC Hydro should provide additional scenarios of the portfolio analysis model to include the GL Garrad Hassan report,* Assessment of the Estimated Costs of Wind Energy in British Columbia*, May 2012, or a comparable updated assessment of BC's onshore wind resource potential.***

The portfolio analysis appears to have been carried out using DSM Option 2 but not Option 3.[70] This would tend to over-estimate the amount and cost of supply-side resources needed and magnify cost differences between portfolios.

> ***Recommendation 8: In the final IRP, BC Hydro should provide additional scenarios of the portfolio analysis model to include DSM Option 3.***

> ***Recommendation 9: In the final IRP, BC Hydro should provide amended Base Resource Plan and Contingency Resource Plans that reflect the outcomes of the additional modelling of Recommendations 8 & 9.***

The Draft IRP does not appear to assign any value to the seasonal load shape of wind power, specifically the seasonal maximum of generation which tends to coincide with BC Hydro's maximum seasonal loads, and relatively low generation during seasons of greater generation from other resources, particularly during the freshet period.

> ***Recommendation 10: In the final IRP, BC Hydro should assess and quantify the value to the BC Hydro system of the seasonal shape of wind generation, and incorporate the conclusions into the Base Resource Plan and Contingency Plans.***

(b) Resource Planning Risk Framework – IPP Attrition Uncertainty

BC Hydro says that the "IPP attrition rate was flagged as a key uncertainty that could affect the comparison of resource options."[71] It is not clear whether or how BC Hydro included an estimated IPP attrition rate in the comparison of resource options in the Draft IRP. This is important because presumably it affects the estimated merits of Site C versus IPP power.

Furthermore, BCSEA is concerned that the analysis of IPP attrition rate uncertainty is flawed in two ways:

First, the "Highest Credible Bound" of Table 5-14[72] includes the attrition from the F2006 Call for Power of two coal-fired power plant proposals, which were lost because of a change in government policy direction, rather than through a failure by the proponents, a change in market conditions, or any other factor that operates independently from or randomly with respect to the power acquisition process. The government intervention was a deliberate act, taken with knowledge of BC Hydro's plans and power acquisitions, and should not be taken as in any way

[69] Draft IRP, Table 6-9, page 6-50.
[70] Draft IRP, Figure 6-3, page 6-13 and Figure 6-15, page 6-45.
[71] Draft IPP, section 5.2.3.6, page 5-43.
[72] Ibid, Table 5-14 and footnote, page 5-44.

representative of the probability of a project failing.

Second, the attrition rates are given as a percentage of energy volume. Project fail on a per-project basis, depending of proponent failures, changes in market conditions and other such factors. There is no reason to believe that project attrition is correlated to project size. The effect in the current analysis is to over-weight the significance of the two large (coal-fired) projects that failed in the F2006 Call. The 'Highest Credible Bound' should probably be closer to 40% than 70%.

BC Hydro should also consider a weighting of attrition probability based on a qualitative assessment of the ease or difficulty of bidding conditions in BC Hydro's calls. Attrition probability will be affected by factors such as the time proponents are allowed to prepare their bids and the extent to which required permitting and engagement with local stakeholders and affected first nations has been completed when contracts are awarded.

> ***Recommendation 11: In the final IRP, BC Hydro should revise the IPP attrition uncertainty analysis to remove methodological flaws, and it should transparently explain how the analysis affects the portfolio assessments. Alternatively, BC Hydro should remove the analysis from the IRP if it is not relevant.***

(c) Market Price Forecasts

BC Hydro's market price forecast analysis for gas appears to be reasonable. BCSEA does not recommend adopting a lower price forecast for gas.

(d) Site C and Capacity Requirements

Based on the analysis and discussion provided above, BCSEA says that BC Hydro has not convincingly established that Site C is needed or a preferred energy supply resource relative to available demand-side resources and alternative, non-GHG emitting generation resources.

A critical question is whether Site C is needed for capacity reasons. Table 3 analyzes the amount of DSM capacity savings that BCSEA believes can realistically be achieved in a cost-effective manner, based on the evidence of John Plunkett of Green Energy Economics Group, filed in the review of BC Hydro's F2012-14 RRA application.[73]

Table 3: Comparative DSM savings plans, Capacity (MW/year cumulative)

DSM Plan	F2012	F2016	F2021	F2031
A: BC Hydro IRP (Option 3) *	99	991	1,529	2,047
B: GEEG RRA, programs only **	44	1,110	2,003	2,863
C: GEEG RRA, programs only + C&S + rates ***	165	1,767	2,813	3,939
D: BC Hydro RRA Load Displacement DSM ****	12	104	153	104
E: GEEG RRA, programs only + C&S + rates + L.D.	177	1,871	2,966	4,043
F: B minus A (rounded)	(60)	100	500	800

[73] Exhibit C-10-13, BC Hydro F2012-14 RRA proceeding, *Direct Testimony of John Plunkett.*

G: C (C&S & rates discounted 50%) minus A (rounded)	0	400	900	1,400
H: E (C&S & rates discounted 50%) minus A (rounded)	0	500	1,000	1,500

* From Draft IRP, Appendix 9B, Table 4, *BPR – Capacity*.

** From Exhibit C-10-13 of the review of BC Hydro's F2012-14 RRA and F2012-13 s 44.2 DSM Expenditure Schedule, Exhibit JJP-2, Appendix C, page C-4, *Cumulative Energy Savings Since F2008*, with the following adjustments (by T. Hackney): (a) base year adjustment made by adding a value for F2012 for programs only estimated from Ex. B-1-3B, Amended Attachment 5, Table 2; (b) line loss factor of 1.12 assumed. Does not include load displacement.

*** From *GEEG RRA DSM, programs only* (above), with values added (by T. Hackney) for "Rate Structures" and "Codes and Standards," taken from the Draft IRP, Appendix 9A, Table 2, except figures for F2012 and F2013, taken from Ex. B-1-3B, Attachment 5, Table 2. Does not include load displacement. Line loss factor of 1.12 assumed.

**** From Exhibit B-1-3B, review of BC Hydro's F2012-14 RRA and F2012-13 s 44.2 Expenditure Schedule, Amended F12/F14 RRA – Amended New Appendix II, Amended Attachment 5, Table 2, Load Displacement for Residential, Commercial and Industrial Sectors. Line loss factor of 1.12 assumed. (The Draft IRP does not provide a numeric break-out of DSM savings from load displacement as was provided in the F2012-14 RRA and F2012-13 s 44.2 DSM Expenditure Schedule filing, but load displacement forms part of the DSM savings BC Hydro lists under DSM programs.[74])

Note: The base year adjustments should be seen as approximations and may not be methodologically accurate. For example, they may not properly reflect decay of savings.

Explanation: 'C' adds the DSM savings proposed by Mr. Plunkett ('B') to DSM savings proposed by BC Hydro in the Draft IRP for codes and standards and conservation rates. 'E' adds Mr. Plunkett's proposed DSM to BC Hydro's DSM proposed savings for codes and standards, conservation rates and load displacement. 'F' compares the DSM savings proposed by BC Hydro to those proposed by Mr. Plunkett. 'G' adds Mr. Plunkett's proposed DSM savings to BC Hydro's proposed savings for codes and standards, and conservation rates; however, discounting the codes and standards and conservation rates savings by 50% as an assumed figure to account for possible overlaps with program savings. 'H' adds load displacement savings to 'G.'

Discussion: The Draft IRP Base Resource Plan shows BC Hydro's 2011 Mid Load Forecast Surplus/Deficit situation (including the "initial LNG" load) as being in surplus during the planning period, with reliance on Site C as a 'future resource,' coming into service in F2022 and providing capacity of 1,100 MW.[75] Table 3, above, shows that if BC Hydro were to pursue cost-effective 'Tier 1' DSM program savings, as recommended in Mr. Plunkett's evidence,[76] combined with BC Hydro's proposed DSM savings from codes and standards and rates (using a conservative 50% discount rate to account for possible overlap with program savings), and additional 1,000 MW of DSM capacity would be available by F2021, sufficient to substitute for

[74] Draft IRP, Appendix 2B, sections 3.1, 4.1 and 5.1.
[75] Draft IRP, Appendix 9B, Table 4.
[76] Exhibit C-10-13, BC Hydro F2012-14 RRA proceeding, *Direct Testimony of John Plunkett.*

Site C's capacity. The capacity surplus would be even more favourable without the "initial LNG" load. (Please see above, under 'Demand-Side Measures,' for a discussion of the reliability of the DSM estimates and deliverability risk.)

BCSEA concludes that BC Hydro has not shown that Site C is a required resource or the most cost-effective resource for capacity purposes at this point.

> ***Recommendation 12: In the final IRP, BC Hydro should remove the recommendation that Site C should be pursued for its earliest in-service date.***

(e) Gas-fired generation

As discussed above under 'Greenhouse Gas Emissions,' BCSEA views GHG emissions as a key factor in determining that gas-fired generation should be weighed qualitatively as an undesirable resource. BC Hydro should strive to minimize the GHG emissions of its system and should strive to maintain the '93% clean or renewable' standard. Although there may be 'headroom' to develop gas-fired generation under the 93% limit, it is still undesirable from a GHG perspective. BCSEA notes that the comparison in Table 6-3 of the 'all clean' portfolio against portfolios with gas-fired generation only shows cost advantages of 0% to 4% for gas-fired generation.[77] This is trivial compared to the negative factor of GHG emissions.

BCSEA supports BC Hydro in not recommending the development or procurement of gas-fired generation in the Draft IRP for the Base Resource Plan. BCSEA also supports BC Hydro in not recommending base-load gas-fired generation in the BPR or the Contingency Resource Plans.

BCSEA suggests that the additional scenarios requested in Recommendations 8 and 9, above, should challenge the need for gas-fired generation as a capacity resource.

> ***Recommendation 13: In the final IRP, BC Hydro should reassess the need for gas-fired capacity resources in the Contingency Resource Plans.***

BC Hydro should maximize non-fossil fuel capacity resources. BCSEA encourages BC Hydro to develop its analysis of pumped storage and time-of-use rates, and to maximize its programs to encourage load displacement by its customers.

> ***Recommendation 14: In the final IRP, BC Hydro should provide a robust enough assessment of pumped storage that it can potentially be adopted as a resource.***

(f) Market reliance for short-term energy "Mid-Gap"

BCSEA supports BC Hydro's proposed approach to address the potential short-term energy "mid- gap."[78] It is better to rely on market purchases in the short term than to procure resources hastily that may not be the most appropriate and cost-effective.

(g) Procurement:

BCSEA agrees with BC Hydro's approach of seeking independent advice on procurement and the engagement of First Nations and stakeholders.[79] However, based on the discussion (above)

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[77] Draft IRP, Table 6-3, page 6-14.
[78] Draft IRP, section 6.8.2, pp. 6-88 to 6-91.
[79] Draft IRP, page 6-87, text and footnote 26.

on the new information on BC's wind resource by Garrad Hassan,[80] BCSEA questions the conclusion that "the economic benefits of geographic diversification are outweighed by the cost of acquiring diversified wind projects."[81]

> ***Recommendation 15: In the final IRP, BC Hydro should reassess costs and benefits of region-specific power acquisitions versus geographically divers acquisitions.***
>
> ***Recommendation 16: BC Hydro should take steps to hold open the option to procure renewable, non-GHG emitting power in the short term in sufficient quantities to defer the need for Site C.***

BCSEA urges BC Hydro, to the extent possible, to provide regular, predictable power procurement opportunities, to make it easier for developers to plan and develop their projects. BCSEA anticipates that this would lead to higher quality, more cost-effective offers to BC Hydro.

(h) Uncertainty of "Initial LNG" demand

The potential for the "Initial LNG" demand – and the additional potential for the "LNG3" demand starting about F2020 – represents a very large increase in the load forecast uncertainty compared with recent planning exercises by BC Hydro. There is a heightened potential for over-building resources or shortfalls in meeting demand.

BCSEA supports BC Hydro to lead toward conservatism in committing to new generation acquisitions, particularly those that would increase BC's GHG emissions. BC Hydro should not make commitments for new infrastructure or generation for the "Initial LNG" load until such time as that load is confirmed. As noted above, BC Hydro has good access to 'bridging' resources, which can be used to avoid risky commitments to potentially stranded assets.

BC Hydro should continue to do the things it should do anyway, maximizing its cost-effective DSM resources and proceeding with cost-effective Resource Smart capacity additions.

BC Hydro should hold open its alternatives for meeting the new demand, should it materialize: mainly renewable energy and capacity resources and Site C.

BCSEA also notes that government has said it will conduct a review of BC's electricity policy, and this is an additional reason to hold options open, rather than making commitments.

VI. BCSEA's Responses to BC Hydro's Recommended Actions

Table 4, below, lists selected recommendations by BC Hydro in the Draft IRP and BCSEA's responses.

Table 4: BCSEA's Comments on BC Hydro's Draft IRP Recommended Actions

BC Hydro Recommended Action	BCSEA Response
1. Pursue DSM Option 3	BCSEA urges BC Hydro to meet the 'Tier 1'

[80] *Assessment of the Estimated Costs of Wind Energy in British Columbia*, GL Garrad Hassan Canada, Inc., 24 May 2012, prepared for Canadian Wind Energy Association.
[81] Draft IRP, page 6-103.

	DSM savings goal of procuring cumulative DSM savings of 2% of sales. See above: *Demand-Side Measures (DSM).*
2. Advance DSM Options 4 & 5	BCSEA supports this, with qualifications. See above: *Demand-Side Measures (DSM).*
3. Pursue DSM Capacity Options	BCSEA supports this.
4. Continue to Pursue Site C [for the earliest in-service date]	BCSEA opposes this. See above: *Resource Planning Analysis and Resource Plans: Site C and Capacity Requirements*
5. Develop Revelstoke Unit 6	BCSEA supports this. Revelstoke 6 will be a valuable addition to BC Hydro's system.
6. Pursue Bridging Capacity from Existing Resources	BCSEA supports this. Given the large uncertainties in the load forecast, BC Hydro should open options that allow it flexibility and to mitigate the risk of stranded assets.
7. Investigate and Advance Additional Resource Smart Projects	BCSEA supports this. BC Hydro should maximize the development of cost-effective capacity projects in its system.
8. Upgrade Existing WSN to SKA 500 kV Transmission [Prince George to Skeena]	BCSEA supports the "Clean Power with Transmission" option and opposes the "Clean with SCGTs" option.
9. Develop 2,000 GWh/year Clean Procurement Option	BCSEA supports clean power procurement, but not necessarily this volume and timing. See above: *Resource Options Report – Wind Power*; and *Resource Planning Analysis and Resource Plan*.
10. Explore Pumped Storage	BCSEA supports this. See above BCSEA's *Recommendation 14*.
11. Assess New Transmission Infrastructure from Peace River to North Coast [Prince George to Terrace and Kitimat; and Peace River region to Prince George]	Customers causing major new loads requiring major transmission infrastructure or generation resources should pay for such additions; and infrastructure to serve demand from LNG plants should not be subsidized by ratepayers. See above: *Greenhouse Gas Emissions*.
12. Develop Future Clean Procurement Options for LNG3	Transmission infrastructure and generation resources required to serve demand from LNG plants should not be subsidized by ratepayers. LNG loads should be electrified from non-GHG emitting resources. See above: *Greenhouse Gas Emissions.*
13. Explore Gas-Fired Contingency Capacity	BCSEA opposes this. See above: *Greenhouse*

Options.	*Gas Emissions*; and *Resource Planning Analysis and Resource Plans: Gas-Fired Generation*.
14. Monitor Fort Nelson/Horn River Basin Load and Supply	Customers causing major new loads requiring major transmission infrastructure or generation resources should pay for such additions; and infrastructure to serve demand from natural gas production operations should not be subsidized by ratepayers. See above: *Greenhouse Gas Emissions*.
Section 9.5.1 Province-Wide Electrification/ Greenhouse Gas Reduction Initiatives (p. 9-78)	BCSEA supports: (1) continued analysis and support to government on electrification in response to climate (GHG reduction) policy; (2) Continued distribution system studies, including smart grid work; and (3) continued work to develop capacity resources, except that BCSEA does not support natural gas-fired capacity resources.
Section 9.5.2 Export Market Analysis (p. 9-79).	BCSEA agrees with BC Hydro's conclusion that current market conditions do not justify further action at this time.
Section 9.5.3 Generation Clusters (p. 9-80)	BC Hydro should continue to monitor the situation, especially if further resource planning analysis indicates a benefit to holding a region-specific power call. See above: *Resource Planning Analysis and Resource Plans: Procurement*.
Section 9.5.4 Geothermal (p. 9-81)	BCSEA supports efforts by BC Hydro to enable geothermal power to be acquired, including financial ways in which the resource proving threshold may be overcome.

VII. Process to Review BC Hydro's Resource Plans

While BC Hydro made good efforts to involve stakeholders in the IRP process, BCSEA believes that the most appropriate forum in which to review BC Hydro's plans is that of the BC Utilities Commission. BCSEA suggests that it would be appropriate for government to put the Draft IRP before the Commission for a full public review.

VII. Compilation of BCSEA's Recommendations

Recommendation 1: BC Hydro should continue to maintain the "93% clean or renewable" standard in the IRP and, for any gas-fired generation included in the IRP, BC Hydro *should take into account how that generation would affect BC's GHG reduction targets.*

Recommendation 2: BC Hydro should amend the Draft IRP so that the final IRP contains a firm plan to take demand-side measures to reduce its expected increase in demand for electricity by the year 2020 by at least 66%, to comply with BC energy objective 2(c). It is particularly important that the final IRP should meet the 66% objective even under the "with initial LNG" load scenario.

Recommendation 3: In the final IRP, BC Hydro should commit to achieving energy savings from DSM programs of 2% of BC Hydro's energy sales ('Tier 1' savings), while maintaining the 'Option 3' energy savings from codes and standards and conservation rates.

Recommendation 4: BC Hydro should take immediate steps to obtain as soon as is practical a new conservation potential review to update the 2007 Conservation Potential Review, including an assessment of codes and standards and conservation rates.

Recommendation 5: BC Hydro should take steps to ensure that its next DSM plan and expenditure schedule to be filed with the BCUC under the Utilities Commission Act *presents 'codes and standards' and 'rates' measures that are characterized sufficiently to be implemented.*

Recommendation 6: In the final IRP, BC Hydro should include the analysis of the GL Garrad Hassan report, Assessment of the Estimated Costs of Wind Energy in British Columbia, *May 2012, and an updated assessment of BC's onshore wind resource potential.*

Recommendation 7: In the final IRP, BC Hydro should provide additional scenarios of the portfolio analysis model to include the GL Garrad Hassan report, Assessment of the Estimated Costs of Wind Energy in British Columbia, *May 2012, or a comparable updated assessment of BC's onshore wind resource potential.*

Recommendation 8: In the final IRP, BC Hydro should provide additional scenarios of the portfolio analysis model to include DSM Option 3.

Recommendation 9: In the final IRP, BC Hydro should provide amended Base Resource Plan and Contingency Resource Plans that reflect the outcomes of the additional modelling of Recommendations 8 & 9.

Recommendation 10: In the final IRP, BC Hydro should assess and quantify the value to the BC Hydro system of the seasonal shape of wind generation, and incorporate the conclusions into the Base Resource Plan and Contingency Plans.

Recommendation 11: In the final IRP, BC Hydro should revise the IPP attrition uncertainty analysis to remove methodological flaws, and it should transparently explain how the analysis affects the portfolio assessments. Alternatively, BC Hydro should remove the analysis from the IRP if it is not relevant.

Recommendation 12: In the final IRP, BC Hydro should remove the recommendation that Site C should be pursued for its earliest in-service date.

Recommendation 13: In the final IRP, BC Hydro should reassess the need for gas-fired capacity resources in the Contingency Resource Plans.

Recommendation 14: In the final IRP, BC Hydro should provide a robust enough assessment of pumped storage that it can potentially be adopted as a resource.

Recommendation 15: In the final IRP, BC Hydro should reassess costs and benefits of region-specific power acquisitions versus geographically divers acquisitions.

Recommendation 16: BC Hydro should take steps to hold open the option to procure renewable, non-GHG emitting power in the short term in sufficient quantities to defer the need for Site C.

VIII. Conclusion

BCSEA appreciates BC Hydro for having provided this opportunity for it and other TAC members to participate in the development of the IRP and provide inputs to the Draft IRP.

Appendix 1

Exhibit C-10-13, BC Hydro F2012-14 RRA, *Direct Testimony of John Plunkett on behalf of the British Columbia Sustainable Energy Association and the Sierra Club of British Columbia*, Green Economics Group, 2012.