BC HYDRO

DUKE POINT POWER

EPA APPROVAL APPLICATION

PROJECT NUMBER 3698354

FINAL ARGUMENT

ON BEHALF OF

THE JOINT INDUSTRY

ELECTRICITY STEERING COMMITTEE

(“JIESC”)

FEBRUARY 4, 2005

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ELECTRICITY PURCHASE AGREEMENT REVIEW

1. EXECUTIVE SUMMARY

The JIESC believes that this is one of the more important hearings that has faced this Commission in some time. The issues are important and unfortunately prone to unfair over-statements. BC Hydro would have you believe that there is an eminent crisis on Vancouver Island that can only be addressed through the immediate addition of generation and that the Call for Tenders (CFT) conducted by BC Hydro has brought forward the least cost long run solution. The JIESC does not believe that BC Hydro is correct on either account.

In their arguments BC Hydro and Duke Point Power seem largely concerned with process. The JIESC is concerned with the long-term cost of this Agreement to all BC Hydro customers and believes that issue, not process, is the proper focus for the Commission to take in reviewing whether or not the EPA is in the public interest.

The JIESC believes the Duke Point Power (DPP) Electricity Purchase Agreement (EPA) should not be approved for four principal reasons:

- Vancouver Island has enough electrical capacity and energy to be able to wait for another year for a better solution for more capacity;
- The EPA is too expensive in comparison to other long term alternatives;
- The EPA imposes unreasonable gas, electricity and energy margin risks on BC Hydro's customers; and
- The Cost Effectiveness Analysis done by BC Hydro grossly overstates the benefits of the EPA and understates the benefits of the alternatives.

1.1 Vancouver Island is not facing an immediate crisis

The JIESC accepts the Commission's finding, based on the evidence of Mr. Mansour[1], that in the long term it is in the interests of all customers that there be increased generation on and transmission to Vancouver Island. However, the JIESC does not accept that means that this 25 – 35 year EPA should be entered into by BC Hydro. Mr. Mansour, Senior Vice President,

[1] Transcript, Vol. 10, p. 2285

System Operations and Asset Management, of BC Transmission Corporation (BCTC) was very clear that through a use of a variety of mechanisms, BCTC is comfortable that they can maintain reliable service to Vancouver Island until new transmission arrives on the Island in 2008 and not violate planning criteria[2].

1.2 The EPA Proposal is a Very Expensive Long Term Solution to a Short Term Problem

In its September 2003 Decision the Commission found that BC Hydro had not demonstrated that the Vancouver Island Gas Plant (VIGP) proposal was the least cost solution and urged BC Hydro to conduct a Call for Tender process to bring forward the least cost project.[3] Unfortunately, the CFT process was limited and flawed resulting in an Electricity Purchase Agreement (EPA) with Duke Point Power (DPP) which will lead to high cost and high risks for ratepayers if approved.

The cost per MWh in 2007/08 is approximately $90 at an 80% load factor, BC Hydro's view of a likely operating level, and is approximately $125 per MWh at a 40% load factor, a higher load factor than anticipated by the JIESC expert witness.[4] When these costs are compared to BC Hydro's own Integrated Electricity Plan costs of new supply for similar resources of roughly $50 – $65 per MWh[5] the cost of the EPA cannot be justified and must not be incurred.

1.3 Gas Price, Electricity Price and Energy Margin Risk

BC Hydro, by basing its electricity price forecasts on the cost of converting natural gas to electricity, has overstated the utilization of the EPA and overstated the likely margin to be achieved on electricity sales by 69%.[6] In addition, by agreeing to accept the gas price and transportation risk on its customers instead of DPP, BC Hydro has exposed its customers to substantial financial risk over a 25 year period.

1.4 The Cost Effectiveness Analysis

BC Hydro's executive undertook a Cost Effectiveness Analysis of the outcome of the CFT after the completion of the CFT process and prior to signing the EPA. That process showed the DPP

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[2] Transcript, Vol. 10, p. 2285
[3] BCUC VIGP Decision, September 8, 2003, p. 77
[4] Exhibit C19-23; C19-11, Evidence of L. Guenther, Attachment B, DPP Costs
[5] Exhibit C19-21, BC Hydro IEP, p. 15
[6] Exhibit C19-24, Supplement Evidence of Mr. S. Fulton

EPA, if new electricity transmission reaches Vancouver Island in F2009, as the most desirable outcome by $16 million in one of three scenarios. In the other two scenarios the alternatives were more attractive.

However, that analysis overstated the benefits of the DPP EPA by improperly accounting for backfill energy for the non-DPP scenarios. If that backfill energy alone were handled properly, the NPV of the Tier 2 award would increase by approximately $115 million and the NPV of the "No Award" option would increase by approximately $172 million leaving Tier 1, the DPP EPA in third place, a solid $61 million behind Tier 2, and $156 million behind the "No Award" option.[7] Other adjustments for additional gas transportation, gas price, electricity price, energy margin and utilization risks not taken into account by BC Hydro, make the DPP EPA even less attractive.

1.5 Appropriate solution

The JIESC believes that a reasonable, fair and reliable solution to Vancouver Island's capacity shortage is to use the bridging options spoken to by Mr. Mansour and others and to expedite the planned 230kV transmission line to alleviate long-term capacity concerns on Vancouver Island. With the new transmission line in place, a province wide, all source call for generation should be held. The Duke Point Project and other Vancouver Island bidders should be eligible for that call which would test their proposals against all other generation projects, with due regard for long term cost and risk, something that has not happened in this process.

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[7] JIESC Argument Section 5.4

2. IMPORTANCE AND URGENCY

2.1 General Comments

The fundamental reason for the award of the contract to Duke Point Power LP is the retirement for "planning purposes" of the High Voltage Direct Current (HVDC) transmission lines in 2007. In the view of BC Hydro the loss of this transmission capacity requires either additional transmission to the Island or on-Island generation in order to meet "planning criteria".

2.2 Demand Forecast

BC Hydro provided a revised forecast of VI demand. That forecast, as demonstrated by the graph in the updated evidence of Mr. Miller, shows that BC Hydro has anchored the forecast on the most recent demand estimates for VI and the Gulf Islands. The history provided in those graphs shows that the peak demand is highly variable and a new demand is not determinative of higher demand in subsequent years.[8] As acknowledged by Mr. Miller, there is a risk of being higher or lower than his forecast using historical data and employment and population statistics. However, Mr. Miller's forecast is much lower than the BC Hydro forecast.

The BC Hydro demand forecast update also made assumptions about industrial demand growth. Since that forecast, Port Alice has shut down and Norske has announced the shutdown of a newsprint line in Port Alberni.

2.3 Supply Load Balance

The latest projection of the load-supply balance for Vancouver Island is set out in Exhibit B98. In that exhibit the supply to the Island for the year 2007 is described as follows:

Source	**Megawatts**
Hydroelectric Resources	450
500 kV Transmission	1300
HVDC Transmission	240
Existing Purchase Contracts	266
Total Supply	**2256**

[8] Exhibits C20-36, C20-37

This is the total supply "for planning purposes". Not included above, as is appropriate "for planning purposes", is the second 500 kV transmission circuit. This second circuit has a capacity identical to the one circuit included in the table above or another 1300 MW bringing the total supply capability to 3551 MW. The two 500 kV circuits alone have enough transmission capacity to provide 2600 MW which is sufficient, by themselves, to meet the total load on the Island out to the year 2016, according to the peak load forecast contained in B98. For the supply on the Island to be in jeopardy in the foreseeable future one of these lines must be out of service during the one or two weeks a year when very low temperatures are experienced on Vancouver Island.[9]

Also not included in Exhibit B-98 is the expected completion of the 230 kV transmission line to the Island in 2008. When that line is completed, and the HVDC is de-rated "for planning purposes" the supply to Vancouver Island will be as follows:

Source	**Megawatts**
Hydroelectric Resources	450
500 kV Transmission	1300
230 kV Transmission	600
Existing Purchase Contracts	266
Total Supply	**2616**

This supply capacity is adequate "for planning purposes" until 2016 according to the load as forecasted in Exhibit B-98. BC Hydro is therefore proposing a 25 – 35 year contract with DPP to meet a one year shortfall in 2007.

The forecast shortfall for planning purposes for the winter of 2008-2009 is 280 MW. The evidence of Mr. Mansour[10] demonstrates that BCTC can handle this temporary shortfall. During the hearing Mr. Mansour reported on the efforts of BCTC to increase the rating of the 500 kV circuits as well as their efforts to extend the life of the HVDC transmission system.

Mr. Mansour describes BCTC's efforts to increase the rating of the 500 kV circuits[11], stating:

> *The idea is to be able to monitor the temperature of the cable which is in the ocean. The technology is new. There is a reasonable level of confidence that it*

[9] VIGP Evidence, Vol. 4, p. 801-802. Accepted by BCUC for incorporation in hearing record.
[10] Transcript, Vol. 10, p. 2289
[11] Transcript, Vol. 10, p. 2290, line 21

would work, but not necessarily 100 percent. And if we have those measurements, if the operator under severe contingencies or under emergencies could actually look at the temperature of the cable and determine as to how much exactly the cable can take more, if possible.

The estimate right now is – reasonable estimate is up to 120 megawatts. But as I said, it is not necessarily 100 percent certainty, but is not a zero probability either.

Mr. Mansour also reported on BCTC's ongoing efforts to maintain the HVDC system. In response to a question from Mr. Wallace, Mr. Mansour outlines their recent steps as follows[12]:

A combination of a number of things. We are again, just like we said in 2003, we are putting Poll 1 on standby. We load it only when we need to or we have to. So by doing so, we try to extend as much life in it as much as possible. So far we have been successful in doing so. The same with Poll 2.

When I testified in 2003, as far as the cables are concerned, we reported that cable number five, one of the cables of the HVDC cable, had a failure, and we were about to fix it, if you recall, Mr. Chairman, at that time. That was all we were aware of, and then shortly after we found there was another cable which, cable number nine, that was also shown to be faulty, but we fixed that too.

So from a cable perspective, I think we're in reasonable shape. The rest, we have them still on life support.

The following exchange[13] summarizes the current situation from BCTC's perspective:

Mr. Wallace: Q: So for 2007 you would be comfortable with a reasonable level of reliability, to use your terms of about 200 megawatts?

Mr. Mansour: A: Reasonable comfort. Not necessarily the usual certain comfort that I do.

Mr. Wallace: Q: Right

Mr. Mansour: A: But reasonable comfort. Like I would sleep six hours instead of two.

This 200 MW is significantly in excess of the 150 MW minimum BC Hydro was seeking in the CFT process. With the addition of the 200 MW suggested by Mr. Mansour, the maximum deficit on Vancouver Island is reduced from 280 MW in 2008 to 80 MW. This deficit would actually exist only on the coldest winter days when one of the 500 kV circuits is out of service.[14] Further, since the peak load on the island is related to the use of electric power for space heating the

[12] Transcript, Vol. 10, p. 2292-93
[13] Transcript, Vol. 10, p. 2295, line 5
[14] VIGP, Hearing Transcript Vol. 4, p. 801-802

need for this peak 80 MW is only for a few hours on peak days. Clearly entering into an arrangement that contemplates approximately $60 million in fixed annual payments for up to 25 years,[15] including a contract that includes capacity payments of $36 million per year, to solve such a small short term problem is excessive and unreasonable.

2.4 Planning Criteria

In its VIGP Decision the Commission was concerned that failure to proceed with new generation would put the system in violation of the WECC planning criteria. BCTC has made it clear that failure to build the Duke Point Facility will not put it in breach of its planning criteria in its response to Duke Point Power IR # 6.1 (Exhibit C6-6) which stated:

> *When operating, DPP would have a positive impact on transmission reliability on Vancouver Island by increasing reserve capacity under normal operating conditions and by reducing the risk of load shedding under certain severe contingencies. It would have no material effect on mainland transmission reliability. It is not required to maintain compliance with WECC/NERC planning and operating standards. (emphasis added)*

This response was followed up with Mr. Mansour who confirmed its accuracy at Transcript Volume 10, page 2285.

In its final argument,[16] BC Hydro has stated that the NorskeCanada Demand Management Proposal (NCDMP) does not meet their internal N-1 planning criteria. The JIESC suggests that this characterization is a major misuse of the concept. No individual component of an electric supply and distribution system meets, or does not meet, the N-1 criteria. The N-1 planning criteria means the total system is planned so that reliable service will continue should there be a failure of the single largest system component. This criteria is currently met on the Island because the firm load on the Island can be served without using one of the existing 500 kV transmission lines. Should either of the two transmission lines fail, reliable service would be maintained and the N-1 criteria restored once the failed line is back in service. Reduction in firm load by mechanisms such as the NCDMP reduces the amount of generation capacity and/or transmission capacity that is required to maintain the N-1 criteria.

The JIESC submits that it is essential that solutions like the NCDMP be implemented to maximize the cost effective use of the transmission system.

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[15] Exhibit Ex C19-23; Exhibit 19-11, Evidence of L. Guenther, Attachment B, DPP Costs

[16] BC Hydro Final Argument, para. 77

2.5 Completion of the New 230 KV Transmission Line

An important consideration relevant to our argument is confidence in the completion of the new 230 kV transmission lines by 2008. Should the 230 kV line encounter significant delays the need for alternative solutions becomes more pressing. The schedule was extensively discussed during the cross-examination of the BCTC panel by Mr. Keough. Despite a detailed review of every aspect of the project during questioning of Mr. Barrett of BCTC that extended for more than one and a half hours, Mr. Barrett did not vary from his first answer to Mr. Keough's first question reproduced below:

> *Mr. Keough: Q: …….I'm going to ask you guys some questions that are outgoing to be focused primarily on the timing issue related to the in-service date of the proposed 230 kV line.*
>
> *And Mr. Barrett, I understand you to say to Mr. Wallace that the October 2008 date was one that you had a reasonably high level of comfort or confidence in. Did I get that right?*
>
> *Mr. Barrett: A: Correct.*

Mr. Keough's lengthy probing of every aspect of the project only served to clearly demonstrate that BCTC has fully considered the potential problems and has taken steps to assure that the schedule will be met.

2.6 The Long Term Need for New Generation on Vancouver Island

Just prior to the end of the testimony from the BCTC panel, the Chairperson directed questions to Mr. Mansour regarding his support for proceeding with the new generation facility on Vancouver Island. A cursory review of that testimony might lead to the conclusion that Mr. Mansour endorsed proceeding with the Duke Point CCGT. We believe a careful review of the transcript will reveal that Mr. Mansour was endorsing the need for a solution to the capacity problem and the long term benefit of new generation on Vancouver Island, but not necessarily a new generating facility at Duke Point. This is evident from testimony of Mr. Mansour beginning at line 7 of page 2405:

> *The Chairperson: Is it still your view, sir, that the project should proceed before the 230 kV line?*
>
> *Mr. Mansour: A: My view hasn't changed from 2003, Mr. Chairman. The quote of "enough is enough" I still believe in. I have said at that time that we've been studying this for a long time, and let us get the soonest thing that can be there.*

> *And at that time the soonest thing was VIGP 2006, and today we're still there and it looks like 2007. And again if it slips, then I'm facing just the transmission.*
>
> *And that's why I had to think of every bridging mechanism just in case, knowing that from 2003 till today, a year and a half later, and by the time the new order come in, probably two years since we discussed this particular one. I am more concerned even than I was in 2003.*
>
> *My point of get the soonest in there, and if you take the 30-year view, 25- or 30-year view of Vancouver Island, as we said in our submission that combination of generation and transmission to supply the Island is the right long term vision. And the Commission agreed with me on that, in the decision. They said, "We agree with you that that is a good thing." And it was a matter of: What is the best generator to come first? A decision, an opinion, that I cannot express, <u>because I don't know, and I was not involved, in making – and whether this is the most economic one or not. This is what this proceeding is all about</u>. (Emphasis added)*

Mr. Mansour has a problem related to providing <u>long term</u> reliable electric power service on Vancouver Island. He wants the quickest solution possible but has left it to others to determine which is the most economic. Different solutions have different economics and they also, necessarily, have different levels of risk. It is therefore impossible for the Commission to conclude from Mr. Mansour's testimony that he endorses proceeding with the DPP contract as the most desirable outcome. He simply hands the issue back to the Commission which continues to face the requirement of balancing the public interest in both cost and reliability.

2.7 Available Alternatives

In the preceding sections we conclude that the maximum shortfall Vancouver Island faces is no more than 80 MW for one year, the winter of 2007/08, if loads evolve as forecast by BC Hydro, the Norske load (and all other industrial load) remains firm and one of the 500 kV lines fails during one of the coldest days of the year. In the unlikely event this occurs, the JIESC submits there are more cost effective alternatives than entering into a 25 year contract with Duke Point Power. Some options were discussed during the course of this proceeding and the JIESC maintains that there are further options that BC Hydro could and should consider.

2.7.1 Identified Options

Two of the options that were discussed extensively were the proposal from Green Island Energy (GIE) and the NorskeCanada demand management proposal (NCDMP).

Green Island Energy

While the details of the GIE bid are known only to BC Hydro and the Commission Panel, GIE did submit a term sheet, Exhibit C9-3, proposing to provide 75 MW of firm capacity at a fixed 2005 levelized price of $61 per MWH to any interested prospective buyer. The JIESC understands that the GIE proposal met all of BC Hydro's requirements for a successful proposal except that there was no available "portfolio" that would allow the combination of GIE with other qualified suppliers to aggregate the necessary 150 MW. While the $61 per MWH price is a premium compared to other recent results of BC Hydro call for tenders, the JIESC would still rank it much superior to the DPP proposed contract. At full production of 75 MW, the total annual levelized cost for a year's production would be under $40 million.

NorskeCanada Demand Management Proposal

Mr. Mansour was not clear on the extent that he relied on the NCDMP in finding he had reasonable confidence in finding another 200 MW of reliable capacity[17]. To the extent it is not already counted, the NCDMP provides such capacity . The NCDMP anticipates reducing electrical consumption during periods of peak demand at either the Elk Falls or Crofton pulp and paper mills. Capacity of up to 140 MW at Elk Falls is offered at $50,000 per MW/year. On this basis 50 MW could be offered at $2.5 million per year plus the cost of energy at $112.50 per MWH. While NorskeCanada is proposing a 3 year contract, they have also indicated a willingness to adapt their proposal to meet BC Hydro's and BCTC's needs.

Certainly one alternative that is available to meet the deficit expected in 2007/08 with added certainty would be a combination of the GIE proposal and the NCDMP. The 75 MW from GIE plus 50 MW (or more, if necessary) from the NCDMP would meet the expected shortfall in the winter of 2007/08.

Another available option to provide added certainty was identified by BC Hydro in their cost effectiveness analysis, and that was the utilization of temporary generation. Should the DPP contract not receive approval, the feasibility of temporary generation means that no potential supplier would be able to hold BC Hydro hostage to an unreasonably costly proposal.

2.7.2 Unidentified Alternatives

BC Hydro has recently solicited expressions of interest in supplying capacity in British Columbia. The JIESC is not aware of the outcome of that solicitation but would suggest that an

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[17] Transcript, Vol. 10, p. 2294

evaluation of the responses may lead to additional solutions that are even more cost effective that those set forth above.

3. CFT PROCESS

The JIESC is of the view that the CFT process, in spite of what must be acknowledged as a very substantial effort by BC Hydro, is fundamentally flawed. Instead of being a broad CFT designed to attract the maximum number of resources that would solve the immediate capacity problem on Vancouver Island, and incidentally provide cost-effective generation to the system thereafter, the CFT was limited to long term projects, and gave high value to speculative energy margins.

In the VIGP Decision at page 81, the Commission warned BC Hydro against criteria which were too stringent and which might drive up costs or reduce options. Unfortunately that warning went unheeded.

3.1 Role of Bidders in the Commission EPA Review Hearing Process

At transcript page 312 the Chair stated "However, the Commission Panel also notes that in the absence of evidence from developers, it may not be persuaded that the CFT is not satisfactory evidence that Duke Point is the most cost-effective resource for Vancouver Island at this time."[18]

The JIESC appreciates this warning but believes that the Commission must consider very carefully its position on what is adequate evidence with respect to resource bias. The record indicates that initially 23 potential bidders registered, representing a fairly wide variety of potential firm and peaking capacity and energy resources, but that in the end only 6 bids were received, all of which but one depended on natural gas for fuel. Accordingly, the JIESC submits that based on results alone it is likely that there are terms that did result in resource bias, limiting the resources available to BC Hydro under the CFT.

The JIESC recognizes that having disgruntled would-be bidders attend the Hearing to testify about why they did not carry through with their initial interest to a bid would potentially be useful. Unfortunately, though not unexpectedly, this has not happened in large numbers. However, the Commission does know the circumstances surrounding Green Island Energy, Calpine and to a lesser degree Seabreeze. These bids represent a variety of fuels and generation philosophies, e.g. GIE's wood waste fuel and Calpine's peaking plant, and as such provide the Commission with valuable insight into the bidding criteria. The Commission should not take much comfort, in

[18] Transcript, p. 312, lines 18 – 22

terms of confirming the validity of the CFT, from the fact that other bidders did not see fit to participate. This is one Call for Tender and it may well be that a bidder recognizes that his project did not fit the Call for Tenders and that accordingly has not qualified to win the EPA and "moved on" to use DPP's term. That does not mean in any way that the CFT was not unduly constrained or that it did not exhibit significant resource bias to the detriment of present and future ratepayers.

3.2 Role of the Independent Reviewer

Much has been made of the role of the Independent Reviewer in this proceeding. In our submission it is important to remember that the role of the Independent Reviewer was very limited. He made sure all bidders were treated fairly and that there was no deliberate bias. He did not comment on BC Hydro's goals on whether the CFT met them.

The Independent Reviewer made this clear in his Report #4 when he stated:

> *"Our scope of our work did not include review of any matters related to BC Hydro's stated purpose for the CFT from a business, rate payer or regulatory perspective."*[19]

This limited mandate was further confirmed during the hearing in the following exchange:

> *MR. CRAIG: Q: So can I take it from that that you dealt purely with the process as it was laid out and your only concern was did that get applied fairly?*
>
> *MR. SORENSEN: A: Yes.*
>
> *MR. CRAIG: Q: And you didn't deal with the substance of any of the items in the evaluation process?*
>
> *MR. SORENSEN: A: Only to the extent to understand how they were going to be applied within the model. By example, we made no evaluation or valuation of any of the values that Hydro selected. We understood where they would come from and how they would be applied at the model.*[20]

The Independent Reviewer did not evaluate BC Hydro's goals or the effectiveness in achieving them and should not be taken to have ruled on cost-effectiveness of any solution.

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[19] Exhibit B-1, Appendix K-4
[20] Transcript, Vol. 8, p. 1838, lines 1-12

3.3 Resource Bias

The JIESC submits that the goal of the CFT should have been to obtain capacity for Vancouver Island in the short term, with energy being a potentially valuable side benefit. Unfortunately, the CFT was designed in a manner that made a long term capacity and energy the driving factors.

The most important CFT requirements which contributed to resource bias, that is factors which ruled out a resource or favoured a resource, thus reducing available solutions are the following:

- the decision to take the fuel price and fuel transportation risk for natural gas but not other fuels;
- the decision to exclude any truly short term solutions to the capacity problems from the CFT;
- the decision to change the minimum term of the contract from 10 years, at the buyer's election, to 25 or 35 years at BC Hydro's election; and
- the requirement that each project, on its own, must have a 97% reliability.

Each of these criteria eliminated potential projects from contention or transferred risk from the Seller to the Buyer. The end result is that the outcome of this CFT is significantly more expensive and riskier for customers than it should have been.

Two terms in particular influenced the outcome of the CFT, reducing options and increasing risks for customers. The first was the decision to move from a 10 year minimum contract at the seller's option, to a 25-35 minimum at the purchaser's option. While this makes comparison of projects easier, its intended goal[21], in our submission it also reduced the number of projects that might be bid in successfully. This restriction is clearly detrimental to shorter term projects whose proponents cannot guarantee the life of the facilities or co-generation host, or are in a situation like Calpine, whose lease did not cover the full period required.

BC Hydro is sure to urge you not to accept conjecture. The JIESC urges you to use common sense. It is simplistic to think that a change of this nature would not have an impact on potential bidders. Furthermore, in this case we know this change eliminated Calpine whose lease was a

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[21] BC Hydro Final Argument, para. 62

few years too short to meet the CFT requirements.[22] One has to ask should a Peaking Plant that meets all the important requirements in terms of availability and reliability in F2008 be ruled out because it is not available in 2030? Clearly the answer is no. This was an unreasonable and unnecessary restriction on the CFT that unquestionably reduced the options available.

The second term of the CFT that caused a significant effect on the outcome was the decision of BC Hydro to accept the commodity and transportation risk for natural gas but not other fuels. This was done because "BC Hydro feared that bidders would demand an unacceptable premium if required to assume this risk."[23]

This was done without any endeavour to even find out what the price for electricity would have been from gas projects if proponents had been asked to accept the gas price and transportation risk themselves. It is the JIESC's submission that had bidders being required to take this risk the bids would have been much higher because the risks are substantial. Instead, BC Hydro elected to have its customers take the risk, whether they wanted to or not. Furthermore, and equally importantly, having transferred the risk for gas projects to its customers, BC Hydro did not make any risk adjustments in the cost effectiveness analysis and NPV to compensate for this.

The end result was that any bidder considering a non-gas project had to absorb all the risks of its own fuel to provide certainty to BC Hydro, where a gas project bidder did not.

BC Hydro has argued that it is capable of managing that risk because it already buys and sells large volumes of natural gas. That argument does not accord with the evidence or reality. While BC Hydro may well be in a position to buy and sell gas and to hedge the short term gas price risk, it cannot hedge the following long term risks:

(a) that this plant will become technologically obsolete[24];

(b) that its assumption that the electricity price will be determined by a DPP comparable CCGT at the margin for the next 27 years is patently wrong; or

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[22] Exhibit E123 – Calpine letter

[23] BC Hydro Final Argument, para. 30

[24].Dr. Pickel indicated at Transcript 3081-82 that he anticipated a 5 to 10% gas turbine efficiency improvement over the next 4 to 5 years

(c) that other generation options will keep electricity prices down after 2012. The failure to risk adjust the Cost Effectiveness Analysis for the assumption of this very large risk is something that cannot be overlooked by the Commission in considering the cost effectiveness comparison which will be discussed later.

Another element of resource bias was the requirement for 97% reliability for each individual project. Had a more realistic reliability level been set, small projects other than gas turbines might well have been able to bid in, and together could have provided even greater reliability than a single CCGT located at Nanaimo, dependent on gas deliveries from the mainland.

3.4 Failure to Apply CFT Rules to Gas Projects

The fact that there was one set of rules regarding certainty for gas projects and a different set for all other projects became very clear during cross-examination by Mr. G. Fulton. Mr. G. Fulton introduced Exhibit A-40, Section 4(g) of BC Hydro's Fuel Supply Certainty Guidelines, which required Bidders with a "no-tolling" project to:

> *"demonstrate that the bidder's fuel arrangements are sufficient to satisfy its fuel requirements assuming that the bidder's project is operated at Bid Capacity (adjusted for degradation and expected ambient conditions) with a guaranteed availability of at least 97% during the period October to March inclusive."*

It would appear clear that as far as gas supply and gas transportation goes different standards are being applied to "tolling projects" than are being applied to other projects. This is probably because BC Hydro, not the bidder, is responsible for making those arrangements. Be that as it may, it is a discriminatory practice and leaves the customers at considerable risk. The record is clear that BC Hydro's arrangements do not meet the "no-tolling" standard set out above.

- BC Hydro does not have an agreement with Terasen, but rather has a projection of prices subject to clear conditions and reservations expressed by TGVI[25];
- Terasen will not build new facilities without a long term agreement;[26]
- There is considerable upside risk in the Terasen cost projections including a risk that; the revenue cost ratio will not be reduced from 1.25 to 1.10, that Terasen costs will be higher than forecast, including core market gas costs and that Terasen will not be able to

[25] Exhibit A-39, p.1
[26] Exhibit A-39, p.1

pass on some costs to residential customers which will then become the responsibility of BC Hydro customers;

- BC Hydro has not yet been successful in reaching a long-term contract for transportation to Island Generation Project (ICP) and has paid tolls in the past in excess of BC Hydro expectations.

BC Hydro tried to alleviate concerns about the lack of formal fixed arrangements with Terasen on the grounds that LNG or dual-fired generation at DPP were potential backup options. In our submission this evidence is most notable for its flimsiness. DPP did not bid a dual fuel facility and BC Hydro had never even spoken to Duke Point Power about dual firing prior to DPP appearing at the Hearing.[27] When questioned Duke Point testified that incorporating dual firing would be difficult, if not impossible to do for 2007 and would likely need to be done by way of a retrofit.[28]

BC Hydro also suggested that new LNG sources might be an option failing agreement with Terasen. Again it is hard to think that the evidence could be weaker. No one has filed an application for imported LNG unloading and storage facilities in British Columbia, much less on Vancouver Island. There is no evidence as to what the cost of such a facility would be, or what the cost of gas from LNG landed on Vancouver Island would be. DPP clearly stated that an LNG facility would not be located on its property.[29]

If similar suggestions for providing backup security to fuel supply had been put forward by anyone other than BC Hydro in support of their projects, BC Hydro undoubtedly would have disqualified the proponent for failure to prove that it complied with the fuel supply guidelines.

BC Hydro, and inevitably its customers, are carrying the risk of failure to reach agreements with Terasen that provide firm capacity and firm tolls. Those agreements are important and they must be in place prior to approval of any project.

3.5 Failure To Do Any Risk Analysis

The QEM model is a sophisticated, but at the same time, simple spread sheet that not only costs a proposal but unfortunately goes further and values the energy and forecasts an energy

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[27] Transcript, Vol. 10, p. 2234
[28] Transcript, Vol. 10, p. 2227-2230
[29] Transcript, Vol. 10, p. 2240

margin. There is no attribution of comparative risk to any projects. The end result of this is that a low risk project is treated in the same manner as a high risk project, to the detriment of the low risk project and BC Hydro's ratepayers. A dollar of contracted cost and expense, for example a fixed monthly fee, or a fixed commodity charge are treated the same as a speculative dollar of energy margin. The effect of this is to give a bid like DPP's, that has a lot of speculative energy value associated with it, a substantial advantage in comparison to a peaking plant with largely fixed costs and little energy.

3.6 Green House Gas Emissions

The JIESC does not disagree with BC Hydro in its conclusion that DPP may pay all emissions charges, but believe GSXCCC has raised a valid concern that if the emissions are structured as a tax at source, i.e. on the production or sale of natural gas, these costs could end up being paid by BC Hydro's ratepayers. Accordingly, there is an additional risk that is not in any way taken into account in the evaluation of options.

4. QUANTITATIVE EVALUATION MODEL

4.1 Generally

The Quantitative Evaluation Model (QEM) does a reasonable job of modelling a CCGT. However it does a very bad job on gas price, electricity price and energy margin modelling. The years 2008 – 2012 of the model rely heavily on the Henwood model and generally tend to reflect to a significant degree current and future market conditions. Accordingly, they are acceptable to the JIESC. Unfortunately, commencing in 2013 BC Hydro's energy margin is largely dependent on electricity prices based on hypothetical CCGT assumptions, which will be discussed further, later in this argument. These CCGT driven prices generate effectively 91% of the energy margin.[30] Only 9% of the total margin is projected to come in the first 6 years and even less in the first 2 years, when the project is really needed under the assumptions made by BC Hydro. BC Hydro has pointed out that 20% of the NPV of energy margins falls in the first six years of the 25 year life.[31] This remains a small portion, as normally one would expect a large portion of value to be returned in the early years under a NPV model. This result leaves BC Hydro, and most significantly its ratepayers, at an unacceptable level of risk with respect to later recovery of highly speculative margins.

4.2 EPA Expensive

Whether one looks at the EPA's fixed costs or commodity costs it is an expensive agreement by any standard.

Fixed Charges

The fixed charges under the EPA, including Terasen charges before risk adjustment, amount to $60.6 million per year whether any electricity is generated or not.[32] At an 80% load factor the fixed charges amount to $34.35 per MWh; at 20% load factor the fixed charges amount to $137.39 per MWh. In addition variable costs are substantial at current gas prices. Total variable costs at a Sumas gas price of $7.00 CDN, plus compressor gas and Motor Fuel Tax

[30] Exhibit C19-23 Transcript Vol. 15, p. 3113, lines 19-24, Exhibit C19-11, Evidence of Lloyd Guenther
[31] Exhibit B-106
[32] Exhibit C19-23, Exhibit C19-11, Evidence of L. Guenther, Attach. B

(MFT) total $57.70 per MWh in 2007 for a total cost of $92.05 per MWh at a 80% load factor and an astounding $195.09 at a 20% load factor.[33]

BC Hydro and DPP have defended these costs in part based on the optionality inherent in a "dispatchable" facility. Unfortunately, the so called dispatchability is, at least according to the QEM model, much more limited than BC Hydro and DPP have suggested and one would hope. Unfortunately the details of the cost of start-ups are not available to the JIESC, being protected under the Commission's confidentiality order, but their effect is clear. The QEM model shows negative margins in the half million dollar range during a number of months in the first 2 years due principally to limitations on dispatch.[34] Furthermore, the fact that one is not losing money on commodity sales is of little comfort if the plant is idle and one is paying $60 million per year or more in fixed costs without getting any energy output.

4.3 Gas and Electricity Price Forecasts

In the submission of the JIESC BC Hydro has been too optimistic in its electricity price forecasts and is at risk of higher gas prices. This has resulted in excessive energy margin forecasts and unrealistic expectations for the dispatch and unit costs of the DPP EPA.

4.3.1 Generally

BC Hydro uses the Energy Information Administration (EIA) Natural Gas Price Forecast but not the EIA Electricity Price Forecast. In our submission that breaks the vital relationship between the Gas Price Forecast and the Electricity Price Forecast.

Gas price forecasts by EIA and others have been notoriously inaccurate in recent years as evidenced by the critical review contained in Appendix 2, Ex. C19-11, evidence of Mr. S. Fulton and Ex B-84.[35] The difficulties caused by these inaccuracies can be increased if one uses a different basis for forecasting electricity prices than gas prices. For example, if the electricity and gas price forecast come from the same source then at least it is clear that the relationship between the two is likely to remain consistent; that is, if the gas price forecast is low there is a good chance that the electricity price forecast will reflect this and accordingly an appropriate margin is more likely to surface. If on the other hand a low gas price forecast and high

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[33] Exhibit C19-23, Transcript, Vol. 10, p. 2224, Exhibit C19-11, Evidence of Lloyd Guenther

[34] QEM Model, populated with Duke Point data, Exhibit C19-17, line 427-457, Energy Margin; Transcript, Vol. 8, p. 1303

[35] B-84, p. 2

electricity prices are used then the relationship is lost and the result will be exaggerated margins, precisely what the JIESC believes has happened here. In order to use a consistent relationship Mr. S. Fulton looked at the EIA gas and power prices and determined the implicit market heat rate within those prices as a means on checking on BC Hydro's assumptions. This examination showed market heat rates consistent with recent historical, current and futures market heat rates.

BC Hydro has resisted the use of the EIA Power Price material on the grounds that it contains a mixture of regulated and market prices. We reject this as a basis for suggesting that the EIA power prices are too low. Regulated prices are "all in" prices and as such should be higher than marginal prices. There is simply no basis for suggesting that the market price forecast would be higher than the EIA forecast, inclusive of regulated rates. This is tantamount to saying that deregulation leads to higher power prices, not lower.

4.3.2 Use of Derived CCGT Prices

The use by BC Hydro of the CCGT post 2012 leads to inappropriately high electricity market rates, particularly in the Full Case. There is no significant evidence that this reflects market conditions beyond vague suggestions that the market heat rates coming out of the CCGT average post 2012 is "consistent with market tightening". In our submission this is not enough and does not allow for the effect of technological advancements that lower heat rates and the development of alternate lower cost, lower risk energy sources such as coal and oil sands co-generation which have much lower fuel costs.

This is also inconsistent with the last "market-tightening" in 2000 and 2001 – wherein gas price was not the key driver and the market response was such that a number of gas units are now running at non-sustainable utilization levels.

An excessively high market heat rate leads to excessively high "energy margin" and utilization factors and unduly low unit costs.

The evidence is clear that BC Hydro never tested the QEM model by back-casting or by applying future prices to see what happened to the model output. Had it done this, as indicated by Mr. S. Fulton, the model would have turned out a very low utilization factor and very high unit cost. The "Stress" scenarios provided on Jan 17 and discussed in Mr. S. Fulton's Supplemental

Evidence[36] show utilization for “Stress Full” scenarios is only 19% and NPV of Net Energy Margin is just $6 million.

4.3.3 BC Hydro Full Scenario

This scenario assumes that in virtually every hour of every day for every year from 2013 to 2032 the DPP EPA will be dispatched at 100% of its capability and will recover all fixed and variable costs. This is simply not consistent with market experience, or market expectations as disclosed through future prices. It must be discounted as totally unrealistic.

4.3.4 BC Hydro Partial Recovery Scenario

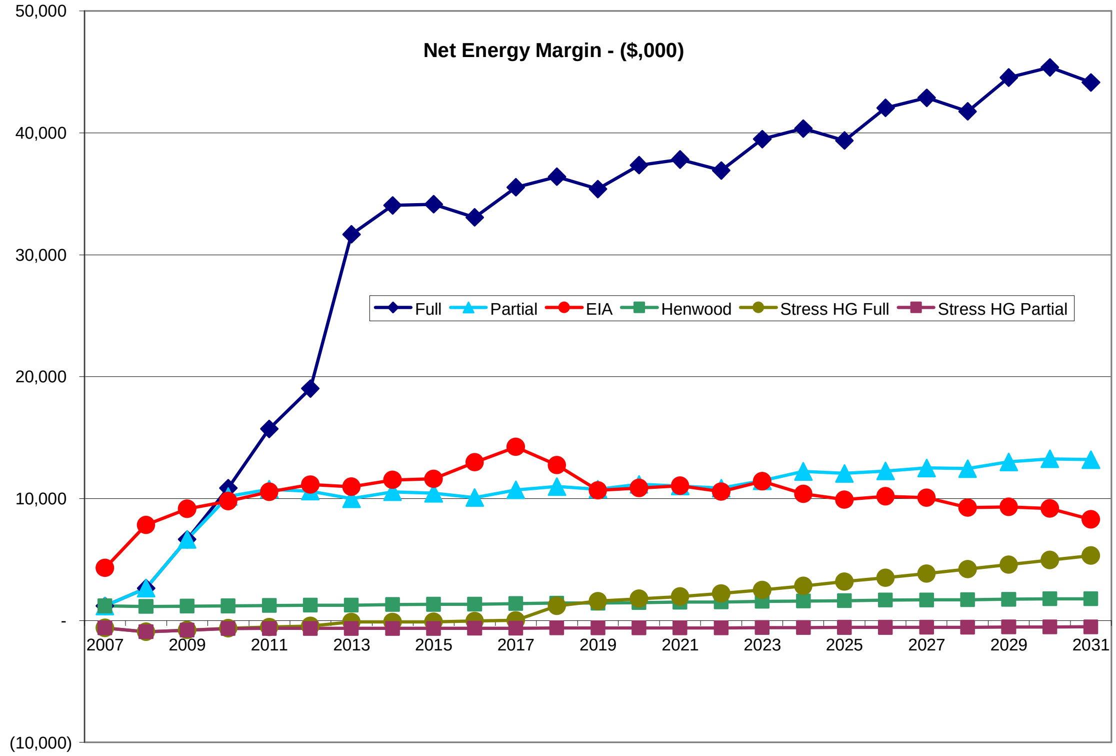
This scenario assumes that the EPA will recover all variable costs plus 25% of capital costs. The effect of this is that in high load hours the plant will usually be dispatched due to the defined positive difference between market prices and variable costs. In low load hours the plant will be dispatched in most circumstances, with some seasonal downtimes, due to limits contained in the EPA and incorporated into the model.[37]

BC Hydro describes Partial Recovery as an extreme scenario and evidence of a market failure.[38] This is not an appropriate description. These outcomes are in the range anticipated by Mr. S. Fulton applying past, current and futures market conditions and looking at EIA gas and power price market ratios. As such they are reasonable outcomes, and should be accepted as calculated, not averaged up.

This is demonstrated clearly in Figure 2 of Mr. S. Fulton’s Supplemental Evidence reproduced below.

[36] Exhibit C19-24
[37] See QEM, populated with Duke Point, Exhibit C19-17
[38] BC Hydro Argument, para. 39-40

Figure 1 - Net Energy Margins ($,000)



4.3.5 BC Hydro Average of Full and Partial Scenarios

While BC Hydro averages the full and partial scenarios in order to give the illusion of reasonableness, while dragging what we would call the reasonable Partial scenario up to an unreasonably high level. This results in the net margin or value of energy being overstated and a 62.5% capital recovery being assumed[39], a level that simply is not justifiable on any basis.

4.4 Evidence of Mr. S. Fulton

The evidence of Mr. S. Fulton is driven by market analysis not optimistic over-simplified modelling.

In Figure 1 at page 5 of Exhibit C19-11, Mr. S. Fulton demonstrates clearly the divergence of the QEM Full Case market heat rate from the QEM Partial Case market heat rate and the market heat rates for 2004 and 2005 AEO. Similarly in figure 3 Mr. S. Fulton shows mid-C

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[39] BC Hydro Final Argument, para. 95

market heat rates based on historic experience, which are well below the QEM full market heat rate.

Finally, Mr. S. Fulton looks at the EPA heat rate comparing it to the Mid-C and Alberta and actual and futures price curves to determine a likely utilization rate of between 25 and 35 percent.[40] This market information must not be lightly dismissed based on unjustified optimism about the DPP EPA CCGT technology setting electricity prices after 2012. Mr. S. Fulton's conclusions are consistent with the BC Hydro Partial Case, the stress case and the alternative heat rate (option 4) provided in Exhibit B-97 by Mr. O'Riley. His conclusions allow for something other than gas covering its variable cost in all situations. In short his conclusions are consistent with market experience and market expectations. They should be accepted.

4.5 BCH Rebuttal Evidence (Exhibit B-97)

4.5.1 Chris O'Riley

Mr. O'Riley's evidence is notable for a number of reasons including:

- He criticized the EIA prices and mixture of regulated cost of service prices and market prices while acknowledging that under the QEM the CCGT price is a pure cost of service price.
- He confirmed that as a predictor of future prices and market prices both forecasts and future prices vary.
- He confirmed that future prices represent prices someone is prepared to deal at and forecast prices do not. In other words somebody is putting their money on the line when they participate in the futures market.
- He confirmed that in the short run at least Powerex and BC Hydro accept "forwards as the best indicator of future prices".

Most importantly, Mr. O'Riley provided us with insight into the price forecasting review process that was undertaken by BC Hydro in early 2004 for the purpose of obtaining approval for "an alternative heat rate scenario in price forecasting process."[41] What was most notable

[40] Exhibit C19-11, Evidence of S Fulton, p. 12-15
[41] Transcript, Vol. 15, p. 3140

throughout this whole forecast review process by the Risk Management Committee, which had substantial participation by BC Hydro CFT personnel, was the unfortunate dismissal of the best of the alternative heat rate scenarios, Option 4.

The January 27th PowerPoint slides[42] indicate a general review of the price forecasting process and a concern (at slide 44) that “an average of several scenarios can be effective for communicating high level results, but does not reflect actual uncertainty.” Unfortunately, BC Hydro appears to still have to find a good way of conveying actual uncertainty.

The slide presentation of February 9, 2004, entitled ‘Price Forecasting Scenarios for Approvals’ is particularly informative. The objectives of this session were to obtain approval for “use of alternative heat scenario” and price forecasting process. A number of options for an alternative heat rate scenario were considered. Slides 6 through 10 include: half cycle economics, alternative fuel technology, improving market heat rate, and Option 4, the current market heat rate. Slide 11 demonstrates that all of the options except Option 4 generate heat rates well above those being experienced in the current market. Option 4 utilizes a market heat rate equal to the then current market heat rate of 8200MMBTU/MWh, or 8700 Gj/MWh. When graphed it becomes clear that the other options, commencing in 2013 and beyond, return prices roughly 20% to 50% higher than option 4, current market heat rates.

The characteristics of Option 4 were listed by BC Hydro in slide 10 as:

- assumes that the market heat rate for 2003 (8200 MMBtu/MWh) continues;
- methodology for calculating the electricity prices does not depend on natural gas fired generation;
- stresses gas electricity relationship and provides low market heat rate;
- defensible: low market heat rate has existed for over two years (note: this is now true for three years).

The February 9th slides conclude on slide 17 indicating that of the alternative heat rate scenarios, option 4 is the “best choice” and “plausible, defensible, meets objectives”.

[42] Exhibit B-97, Evidence of Mr. O’Riley

In spite of the conclusion that Option 4 is the “best choice”, it disappears entirely from the agenda before the February 26, 2004 meeting to be replaced by the full and partial recovery scenarios utilized in the CFT process. As illustrated on slide 7, the result of this decision is market heat rates well above the preferred option 4 levelized market heat rate of 8700, from the start but particularly from 2013 onward. Given the narrow margin by which Tier 1 survived the Cost Effectiveness Analysis there can be little doubt doing away with Option 4 was vital to the eventual approval of the DPP EPA.

4.5.2 Dr. Pickel

The key thing to note about Dr. Pickel is that his evidence only addresses the circumstances in 2008 and 2012 prior to the active reliance on the conversion of gas through the hypothetical CCGT utilized in the full and partial models of the QEM. Dr. Pickel’s evidence is also interesting for what it tells us of the state of the market and the relatively minor position of CCGTs as part of that market. He shows CCGTs as being only 14.3% of the market, and more importantly, although he was a strong proponent of the future importance of CCGTs, he only saw 3000 megawatts of new gas generation coming on between 2008 and 2012[43]. This is less than one-half of one percent of the total system capacity.[44] However in some sense Dr. Pickel was an optimist with respect to future gas growth compared to Mr. Lauckhart as Dr. Pickel saw total growth of 23,000 megawatts (page 9 question 18) in comparison to Mr. Lauckhart’s 10,000 megawatts during the same period[45]. This amounts to more than a one hundred percent difference between two experts for the same client using similar methods.

Dr. Pickel, while maintaining that gas prices drive electricity prices, could not and did not demonstrate that gas prices used in the manner they were used in the BC Hydro models have driven electricity prices in the last three years, or for that matter during the 2000 - 2001 price spike.[46] In spite of this he seems to remain confident that it will do so in the future.

Dr. Pickel criticized Mr. S. Fulton in questions 7 to 9 of his written testimony but either misunderstood that Mr. S. Fulton did not do what was alleged or failed to understand that he, Dr. Pickel, was effectively criticizing the QEM model himself. In response to questions 7 and 8, Mr. S. Fulton did not use monthly values for determining historic dispatch as alleged. He used

[43] Evidence of Dr. Pickel, Ex B-97, Q 14
[44] Transcript, Vol. 15, p. 3105 - 3106
[45] Evidence of Mr. Lauckhart , Exhibit B-97, p. 11, question 13
[46] Exhibit B-97, Evidence of Dr. Pickel, p. 11, line 25

Alberta hourly prices and mid-C HLH LLH daily prices. By contrast the QEM used monthly HLH and LLH for dispatch determination – and also forced dispatch at 60% levels in LLHs when the variable cost to dispatch was greater than the market prices, while the Unit was being dispatched in HLHs in that month. In response to question 9, Dr. Pickel's complaints reply directly to the QEM model but this did not seem to in any way disturb him.

4.5.3 Mr. Lauckhart

Mr. Lauckhart's evidence is very useful for grounding one in reality. He predicts actual dispatch rates for gas and CCGT will be in a range of 35 and 52 percent in 2008. It is our submission that this excess capacity is consistent with the evidence of Mr. S. Fulton and consistent with gas market heat rates continuing to remain low for some time to come. While he suggests this is due to pockets of trapped capacity, Mr. Lauckhart also confirmed during cross examination that in spite of the talk of differences between the various electricity markets there is no evidence to make a case for a position that prices at mid-C regularly and significantly differ from prices elsewhere. While there may be variations from time to time, they go both ways.

Finally Mr. Lauckhart ran an EIA case that essentially confirmed Mr. S. Fulton's EIA gas and power case but then rejected the results because they did not yield the results in terms of capital recovery his model suggested they should.[47] It is our submission that Mr. Lauckhart has failed to take proper account for the current trend away from natural gas and toward coal and co-gen and most particularly the potential for new coal generation and oil sands co-gen. His model included a small amount of new coal generation in Alberta, no new oil sands co-generation and a large amount of CCGT and CGT generation[48]. In our submission these supply assumptions are simply not consistent with how the Alberta market is developing.

4.6 Terasen Gas Delivery Charges and Capability

4.6.1 Terasen Charges

As discussed briefly earlier in the Argument, charges from Terasen remain a substantial source of risk to BC Hydro's customers.

In spite of what undoubtedly have been best efforts on BC Hydro's part, no agreement has been reached with Terasen. Rather what we see are very different views on the principles which

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[47] Exhibit B-97, Evidence of Mr. Lauckhart, p. 16 lines 55-9

[48] Exhibit B-107

govern the rates charged to BC Hydro, not just the dollars and cents making up those rates. In a move that compounds this risk, BC Hydro has elected to use the lower of the Terasen rate forecasts, those based on a 1.10 revenue-cost ratio and not the higher rates based on a 1.25 revenue to cost ratio.

BC Hydro only wishes to be responsible for costs that in its view, it causes. Terasen on the other hand obviously sees BC Hydro as a future source of revenue that will help stabilize a system that has been fraught with difficulties and unrecovered deficits in the past. These views are clearly demonstrated by contrasting BC Hydro's letter of December 13, 2004[49] and the Terasen report[50]. The Commission should not under estimate the time that would be required to resolve these matters. BC Hydro does not yet have a contract for ICP in spite of Commission hearings and hard fought litigation. You should not assume that achieving firm service and rates for Duke Point will be any easier.

It is also not clear at this time what facilities will be required for Terasen to serve BC Hydro, what they may ultimately cost, who will pay for them and when they will be in place. BC Hydro clearly takes a view that the LNG facility is a peaking facility needed to serve the needs of the core market. It is yet to be seen whether the core market or the Commission will agree with this position.

Most importantly BC Hydro has taken what we would suggest to you is the most positive view of the Terasen costs from the Terasen reports and assume that those will be its long term costs. As the evidence of Mr. Guenther contained in Exhibit C19-11 clearly demonstrates, these costs are not without risk. His evidence divides these costs into three separate categories as follows:

(1) LNG Facility related costs and pipeline capital costs are estimated to be $106 million with an increase in the fuel gas ratio;

(2) royalty credits and natural gas supply; and

(3) repayable government loans

In addition, BC Hydro already faces increased Terasen costs of $2 million per year as a result of Vancouver Island Gas Joint Venture (VIGJV) decontracting and may face additional costs due to further decontracting as provided for under the VIGJV contract . The JIESC acknowledges

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[49] Exhibit C19-11, Attachment to evidence of L. Guenther
[50] Exhibit B-12, BCUC IR 1.23.5, Exhibit A-39

that these undetermined costs, which could amount more than $34 million annually, may not come to rest on BC Hydro. However, there is a reasonable possibility that some or all of them may, and some account of that risk should be included in the QEM financial analysis and in the Cost Effectiveness (Appendix J) Analysis.

4.6.2 Terasen Capability

It should also be remembered that the Terasen gas supply reaches the Island through a long pipeline under high pressure travelling through most difficult terrain and under water. It is not free of risks and building a project dependent on this line still leaves Island customers dependent on imported Mainland energy.

5. COST EFFECTIVENESS ANALYSIS – APPENDIX J

5.1 Confidentiality & Scope Limitation

5.1.1 Scope

The Cost Effectiveness Analysis (Appendix J) is critical to the selection of the best option to meet the capacity requirements for Vancouver Island and the province's energy requirements. It is a small document that has attained the significance it deserves, and probably far more significance in this proceeding than was ever intended by BC Hydro. The Commission has adopted the Tier 1, Tier 2 or "No Award" cost effectiveness test as the principal issue in this proceeding.[51] This is not a test that was devised by the Commission, with or without intervenor input. Rather it is a test used by BC Hydro management as a check on the reasonableness of the CFT outcome. While this test was of prime importance to BC Hydro's executives in selecting the best option, in the JIESC's submission it is still too narrow.

5.1.2 Confidentiality

Understanding the Cost Effectiveness Analysis has been particularly difficult due to confidentiality restrictions put on this material by the Commission at the request of BC Hydro. As a result our comments are limited to applying information received from BC Hydro through cross-examination of a general nature to the results of the analysis as provided by BC Hydro. We believe that the conclusions we have drawn are correct. However, they cannot be expressed with the precision that we would like or that would be normal in a regulatory process of this importance.

The confidentiality imposed by the Commission also imposes a special onus on the Commission in this proceeding as was recognized in a discussion between Commissioner Boychuk and Mr. Sanderson at Transcript Volume 4, page 819. Interested parties have not been able to examine the details behind justification for the most important issue in this hearing and they have not been able to test the evidence of the applicant in this area in a detailed fashion. Nor have Intervenors observed the testing of that evidence by the Commission or the Commission counsel through information requests, cross-examination or otherwise. It is even more

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[51] Transcript, p. 313

important than ever that the Commission protect customer's interests by vigorously testing this important confidential information where the customers cannot.

The Commission and BC Hydro must address the issue of confidentiality in the CFT and resulting approvals processes. In the future, the JIESC believes all bids, successful or unsuccessful, should be disclosed as this best serves the public interest.

5.2 Outcomes and Adjustments

BC Hydro says it "does not seek to justify the plant on the value of the energy it will generate".[52] In our submission this position is blatantly wrong and cannot be sustained. A calculation of energy margin is fundamental to both the QEM analysis and the Cost Effectiveness Analysis. The outcomes of the CFT and the Cost Effectiveness Analysis depend on it and would be very different if different assumptions were made as to Energy Margins.

In our submission the Cost Effectiveness Analysis does show, with appropriate assumptions, that the EPA is not only the least cost effective choice, it is the least cost effective by a substantial margin. If one looks at Attachment A of the Cost Effectiveness Analysis – Results Summary for 261 megawatt load requirements for the F2009 cable in service date, one finds that Tier 1 – the DPP EPA, is the lowest cost alternative. It has a minimal advantage of $16 million over the no award option and a $54 million advantage over the Tier 2 option. In the other and more likely scenarios, the DPP EPA is significantly more expensive than either of the other options. In the scenario where the generation cost in the Mainland is assumed to be 10% lower than on Vancouver Island for F2009 cable in service, the NPV of Tier 1 is $84 million less attractive than the "No Award" case and $13 million less than Tier 2; even before the adjustments the JIESC says are necessary are made.

5.3 Backfill Energy Values

One of the principal adjustments made in the cost effectiveness analysis is described as follows[53]:

> *With respect to the energy requirements, the system is starting to become energy critical in 2010. Thus, the analysis "equalizes" the energy being added to the system by 2010. The total volume of new energy supply being added to the system under each of the three CFT outcomes was based on the Tier 1 plant*

[52] BC Hydro Final Argument, para. 36

[53] CFT Report, Appendix J Cost Effectiveness Analysis, p. 1-2

energy contribution, and this translated to approximately 1800 GWh per year as determined by the dispatch model used in the QEM of the CFT. In the Tier 2 case, the volume of expected energy for the two projects as determined by the dispatch model was estimated to be about 600 GWh per year (the vast majority coming from the base loaded biomass project, with very little coming from the gas-fired peaking plant). Therefore, in the Tier 2 case the energy shortfall of 1200 GWh per year was backfilled starting in 2010. Under the "No Award" case, the energy shortfall of 1800 GWh per year was backfilled starting in 2010.

In both the Tier 2 and "No Award" scenarios, the energy backfill was assumed to come from new mainland generation (e.g. new IPPs in response to future calls), at two price scenarios: 100% and 90% of the unit price of the Tier 1 project on VI but without the associated firm gas tolls in both cases. Avoided transmission losses for energy generation on VI versus generation in the Interior was also accounted for, based on a 4.8% energy losses differential between these two locations. Avoided energy losses, as well as the energy volume differences between the three CFT outcomes prior to 2010, were valued using the same Energy Information Administration (EIA) gas and corresponding electricity market price forecast that was used in the QEM model.

During cross examination on exhibit C19-20, BC Hydro confirmed backfill requirements of 1200 gigawatt hours for Tier 2 and 1800 gigawatt hours for the "No Award" scenario. The rationale for the backfill, its size and the value of the associated energy margin on the backfill amounts were discussed at Transcript pages 1907 and following. To the JIESC's surprise BC Hydro had not assumed a gas fired unit on the Mainland but rather a $64 per megawatt hour price in 2006 dollars.[54] This $64 was based on bids received under previous calls. The situation was summarized at page 1910 in the following series questions and answers:

MR. WALLACE: Q: So essentially we have the energy then, if I get it correct, for the 1800 gigawatt hours for Tier 1, clearly based on the EPA; for Tier 2, based on the -- for 600 megawatts and the biomass, for 1200 megawatts based on the EPA, which you say is confirmed by the two other calls.

MS. HEMMINGSEN: A: Correct.

MR. WALLACE: Q: Okay, and for the no award, 1800 gigawatt hours, again based on the EPA.

MS. HEMMINGSEN: A: Confirmed by prior calls.

MR. WALLACE: Q: Confirmed by prior calls. So not surprisingly then, I guess the energy margin should be pretty well the same throughout the three?

MR. PETERSON: Q: Throughout the three outcomes you're talking about?

MR. WALLACE: Q: Yes.

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[54] Transcript, Vol. 9, p. 1909

MR. PETERSON: A: No.

At line 21, page 1911 Mr. Peterson indicated:

"For Tier 1, the energy margin was approximately 172 million (one seven two). For Tier 2 the energy margin was approximately 315 million (three one five). And in the no award case the energy margin is essentially zero."

(emphasis added)

The discussion that attempts to clarify this proceeds over to page 1913 where the following discussion took place at line 18 to 26:

MR. LIN: A: Just to clarify, in the no award scenario, the energy margin may not be necessarily equal to the Tier 1 energy margin, because Tier 1 is assumed to be a dispatchable plant. In the no award, we assume it's a must-run 1800. So subject to confirmation, that may or may not be true. So just to clarify that.

MR. WALLACE: Q: Why would you make a different assumption when you're backfilling on that?

MS. HEMMINGSEN: A: Because we didn't want to backfill with the gas-fired unit, because we've been criticized for doing that, and other resources don't have the same dispatchability, so they tend to be fixed-price, fixed-volume resources.

Finally the value of the margin in the no award scenario, assuming that the Mainland alternative was a CCGT, was clarified at Transcript Volume 10, page 2173 and 2174:

MS. HEMMINGSEN: A: The request was for us to provide the energy margin in the no award scenario, assuming that the Mainland alternative was the CCGT, and Mr. Peterson can speak to the status of that request.

MR. PETERSON: A: Thank you, Ms. Hemmingsen. The energy margin in the no award case, assuming the backfill was done by a CCGT, would be similar to the energy margin in the Tier 1 case, with a couple of -- but there are a couple of impacts. One would be that the -- in the no award case, the timing of the CCGT is about two years after the timing in Tier 1. So you'd lose the first couple of years of energy margin contribution --

THE CHAIRPERSON: Right.

MR. PETERSON: A: -- that we would have seen in the Tier 1 case. And that's worth approximately $3 million. On -- then the second impact is that if a CCGT is located on the lower -- in the Mainland, you would avoid the compressor losses on the Terasen system, which are approximately 5 percent. And that's treated as a variable cost. So on the Mainland side, the variable cost of production is a little less for that CCGT, therefore the dispatch pattern would be different, and you'd have to re-run that project through a new tender sheet, with that change in the assumption on the compressor losses. And the dispatch pattern would be

> *different, presumably it would be higher dispatch, and we didn't undertake to do that analysis, because that's -- takes too much time.*

In our submission, what BC Hydro did in the Cost Effectiveness Analysis was to purport to backfill the energy supply but failed to do so in an appropriate or reasonable way and in a way that is comparable to the net energy margin applied to the DPP EPA. What BC Hydro should have done is credit the “No Award” option with a similar margin to that credited to the Tier 1 Option, $172 million, instead it used zero.

The JIESC also finds the statement that the initial attempt to backfilling at a cost of $64 did not yield any margin to be implausible, given that $64 per MWh is significantly and consistently lower than the full costs of energy from Duke Point. Furthermore, the $64 per MWh that was used is, in our submission, too high to be an approximate for the cost of alternative energy and should be reduced. This would result in a substantially larger margin for backfill in the case of both the Tier 2 and No Award option.

Most important though is BC Hydro’s admission that if they had used a CCGT on the Mainland for backfill purposes the margin would be increased by a figure very close to the $172 million associated with the Tier 1 margin.[55] If this amount is added to the “no award option” and a proportionately reduced amount is added to the Tier 2 option any lingering indecision about the economic benefits of the three scenarios should disappear immediately. Tier 1 immediately becomes the clear loser. The relative benefits of Tier 2 and No Award over the Tier 1 are even greater if one assumes the Mainland price is something less than $64 per MWh and if one takes into account the potential risks associated with Terasen gas transportation.

5.4 Competitiveness Calculation with Backfill and Terasen Adjustments

The following table demonstrates the impact of adding back various credits or charges to the various options under the Cost Competitiveness analysis. It does not include any adjustment for over optimistic energy margins due to the unrealistic gas price, electricity price and revenue margin assumptions discussed previously.

Row 1 is the comparative NPVs of the net projected costs as drawn from the CFT Report – Appendix J. A positive comparative value indicates an alternative has a NPV cost that is higher than Tier 1, DPP by the number of millions of dollars shown. A bracketed value shows the alternative has a lower NPV cost.

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[55] Transcript, Vol 10, p. 2173-2174

Row 2 adjusts the NPV as described above for backfill.

Row 3 shows the Comparative NPVs after adjustment.

Row 4 and 5 adjust the NPV for Terasen risks. These are costs that may be incurred by Tier 1 and therefore on a comparative basis are credited to the other options.

Row 5 shows the Comparative NPVs after adjustment for Terasen and backfill.

Row 6 shows Comparative NPV's after Terasen and backfill adjustments.

Row 7 adjusts the NPV for the difference between \$64 and \$59 on backfill.

Row 8 shows the cumulative comparative NPVs of the costs associated with the three alternative after all of the above adjustments.

		Ref:		**Tier 1**	**Tier 2**	**No Award**
1	Comparative NPV	CFT Report[56]		0	54	16
2	Energy Margin On Backfill	T. 1909 - 1914	1800GWh 1200GWh		(115)	(172)
3	Comparative Sub-total			0	(61)	(156)
4	TGVI Toll Increase after 2011 @ 50% to BCH DPP EPA	LGG Evidence			(114)	(114)
5	TGVI Toll Increase due to Decontracting	BCH GS Evidence	12.5 TJ/day		(10)	(10)
6	Comparative Total			0	(185)	(280)
7	Additional Backfill Adjustments	T. 1909 – 1914 LGG Evidence [57]	\$64 - \$59/MWh		(61)	(92)
8	Comparative Sub-total			0	(246)	(372)

In summary – on a properly comparable basis when all of the adjustments that the JIESC recommends are made the NPV of Tier1, the DPP EPA NPV is \$246 million less than the Tier 2 NPV and \$372 million less than the "No Award" NPV. In other words, in present value dollars, the "No Award" option saves BC Hydro \$372 million dollars compared to proceeding with the DPP EPA.

5.5 Risk/Benefits of Choosing Tier 2

Tier 2 consists of 75 MW of biomass, 47 MW peaking and 140 megawatts of DSM. This combination provides a much reduced risk profile for BC Hydro. For 75 megawatts all of the capacity and energy charges are essentially fixed with GIE taking the risk. With the peaking

[56] Appendix J, Attachment A, 2009 Cable in Service
[57] Transcript, Vol. 12, p. 2521

plant capital costs are reduced and energy exposure is limited. The 140 megawatts of DSM based on the Norske proposal is well suited to Vancouver Island's short term needs and is cost effective, freeing up capacity and energy.

5.6 Risk/Benefits of Choosing "No Award"

The "No Award" option consisted of 140 megawatts of DSM and 120 megawatts of temporary peaking. This again provides the needed short-term capacity and energy required until completion of the 230 kV lines to Vancouver Island with substantially reduced long-term risk with respect to capacity on energy cost.

6. HEARING PROCESS ISSUES

6.1 Section 71 and the Energy Plan

In spite of BC Hydro suggestions to the contrary there is nothing to suggest a Sec. 71 Review should be any less thorough than any other proceeding. The ramifications of a 25 year contract with fixed payments under the contract and fixed gas supply costs are just as serious as constructing and owning a plant and should be viewed as such.

DPP argues that the Energy plan supports use of IPPs. The JIESC does not disagree with the general premise, but the contracts must make sense and be demonstrably in the public interest. Part of the reason for utilizing IPPs was to transfer risk from the customer to the generator. This EPA leaves the largest risks; gas supply, gas and electricity prices, and plant utilization with the customers.

6.2 BC Hydro's Arguments on Behalf of Customers

BC Hydro justifies the EPA on the basis of customer requirements but has consistently opposed its customers being able to properly inquire into the facts around this agreement and has tried to limit the scope of these proceeding. All of BC Hydro's major ratepayer groups have been actively involved in this hearing and have opposed approval of the EPA. Why is BC Hydro so intent on proceeding with it?

6.3 Prior Commission Findings

BC Hydro has consistently tried to bind the Commission with findings, or alleged findings from the VIGP Decision.

There is only one binding finding in the VIGP hearing, that the VIGP was not proven to be the most cost effective resource. In spite of suggestions to the contrary[58] nothing else could have, or should have been the subject of a reconsideration application. We already have too much process. If parties were to start to appealing every secondary observation in a Commission Decision that may or may not be relevant in the future the entire process would soon become totally unworkable and incredibly expensive.

[58] BC Hydro Final Argument, para. 20

As the following passage[59] demonstrates the Commission has made it clear the development and conduct of the CFT have been BC Hydro's responsibility all along.

The Commission Panel, however, is also mindful that a CFT process is within the purview of the utility which, as the Commission accepted in the VIGP Decision, "…has the initial responsibility to plan for its future resource additions". The Commission also noted in that Decision that "It will be BC Hydro's choice whether to proceed with the CFT recognizing that BC Hydro must develop sufficient information to identify the most cost-effective resource addition for Vancouver Island" and that "The results of the CFT would provide valuable information for BC Hydro to discharge its responsibility."

The Commission should not accept BC Hydro suggestions that the Commission created the present situation.[60]. Any problems are entirely of BC Hydro's own making.

6.4 Alleged Damage to Future CFT Processes

BC Hydro has alleged that Commission ruling against the CFT would harm future CFT process and indirectly harm BC Hydro's customers. As customers, the JIESC rejects this argument and wishes to indicate to the Commission that it strongly believes that if the Commission rules on this Application, as it has a duty to do so, and provides good reasons for rejecting the EPA as not in the public interest those problems will be corrected in the future and bidders will come forward as they have for past Calls for Tender. None of the parties to this proceeding have suggested the Commission should approve something that is not in the public interest simply to uphold the process.

6.5 Ability to Direct Duct Firing

The Commission has no ability to approve EPA with Duct Firing.

The Commission can only approve or not approve the contract, but cannot change it.

6.6 Preoccupation with Process

BC Hydro seems to be saying that its customers and stakeholders are too sensitive[61], there is nothing really wrong with the process. This is a condescending and demeaning position to take. Furthermore it is not true. Customers feel strongly about this application because they will be paying for this project for years to come. If BC Hydro is really sure this is such a good contract

[59] Exhibit B-1, Appendix F, BCUC Jan 23/04 letter to BCUC
[60] BC Hydro Final Argument para. 59
[61] BC Hydro Final Argument, para. 109

it should persuade its shareholder to take on the gas price, electricity price and dispatch risks. If this happened it is likely that most customer resistance to the EPA would end.

If BC Hydro is right and if its customers are upset, it is probably because they feel the EPA is not in their interest and it is because this hearing process has not let them address many of the matters they think are important. Furthermore, the process has kept much of the most important financial data and assumptions underpinning the Cost Effectiveness Analysis and DPP EPA selection secret from them. Ways must be found to prevent this from happening in the future.