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February 4, 2005

BC Hydro VICFT
Review of Electricity Purchase Agreement
Intervenor Evidence
Exhibit No. C23-8

VIA Email & Post: Commission.Secretary@bcuc.com

B.C. Utilities Commission
Box 250
900 Howe Street, 6th Floor
Vancouver, B.C.
V6Z 2N3

ATTN: Mr. Robert Pellatt, Commission Secretary

Dear Mr. Pellatt,

Re: Sea Breeze Pacific RTS - Final Submission to CFT Hearings

Enclosed please find both our submission to the CFT process and the results from the recent feasibility study commissioned by Bonneville Power Administration (BPA) and carried out by ABB's independent Study Group. This feasibility study was undertaken in response to Sea Breeze Pacific's request for an interconnection of up to 1,100 megawatts of transmission capacity between Vancouver Island and the Olympic Peninsula.

As has become evident from recent submissions by BC Hydro, Pristine Power and several press stories written quoting principals of both of these organizations, the rationalization for the Duke Point Power gas-fired unit has changed, from a need for a long term capacity and associated energy (which was required to have a high capacity factor) supplier to Vancouver Island, to a poorly conceived way of bridging the capacity shortfall between the de-rating of the current

HVDC lines between Arnott and V.I.T. and the energization of BCTC's new transmission to Vancouver Island for reliability concerns. Neither of these rationalizations have any basis in fact to possibly be the lowest cost option for the Province of B.C.

Sea Breeze Pacific has previously submitted that we believe the best solution for Vancouver Island lies in reinforcing transmission between the Island, the B.C. mainland, and the USA. Our recommendation, as outlined in our previous filings, is the technically and economically superior solution of HVDC Light interconnections, to V.I. While BCTC has re-iterated their belief that a twin 230 kV AC solution is their preferred way to increase the reliability on V.I., they have no studies comparing their 230 kV AC lines plus the Duke Point on Island gas-fired generation with our HVDC Light proposals from the mainland to V.I. and from V.I. to the Olympic Peninsula. The only study to provide any indication is the recently completed BPA feasibility study of the Juan de Fuca Project, our merchant Vancouver Island to Olympic Peninsula HVDC Light transmission proposal, paid for by SBP-RTS.

In all of this discussion, the Duke Point Power Plant has been seen to be the necessary capacity bridge between the 2007 date for de-rating the existing HVDC facilities and the energization of the 230 kV AC lines in 2008-2009. Construction of this plant would be a very real, very large cost to the rate base customers and the taxpayers, through the high costs of the PPA for capacity and the necessary tolling option to insulate (and guarantee the profits of) a private Merchant Generation Company from high natural gas prices. The only rationale that we can imagine for this project is the disposal of BC Hydro's surplus turbines at some large discount of Hydro's costs. These are costs that the rate base and taxpayers will have to bear for many years to come through the entire term of the PPA, both for the gas tolling option and the discounted turbines.

However, the BPA report referenced above indicates <u>the first 550 MW portion of Sea Breeze Pacific's Juan de Fuca project, slated to be energized in 2007, shows that a south to north excess capacity transfer capability of 400 MW exists on a pre-contingency basis</u>. This affirms Sea Breeze Pacific's conviction, expressed in our submission to BCTC Capital Plan and previously in prior CFT submissions. The purpose of the ABB feasibility study was to examine the capability of the Juan De Fuca interconnection on a pre-contingency basis, 1st contingency basis, and common mode contingency basis to find the technical solutions needed to maximize the interconnection capability. SBP-RTS has numerous options to mitigate the contingency issues and already discussed some of these with BPA. The full interconnection study, which will be completed during the next 90 days, will examine these options to find the most desirable.

Therefore Sea Breeze Pacific will have the required transfer capacity installed to V.I. within the specified time frame (fall 2007) regardless of the outcome of the CFT process as we are committed to proceeding with this transmission interconnect, and the appropriate commitments would ensure this line's availability in 2007. The total cost to the rate base of resolving the Vancouver Island capacity issue can therefore be the simple cost of buying the rights to transmission capacity on the Juan de Fuca interconnection. There will be no capital costs or tolling options or arguments about stand-by rates.

Further, given that BC Hydro and BCTC have indicated they will comply with FERC 2003 rules for interconnection procedures and by filing a proforma OATT, under the deferral provisions, we would hereby like to request that the BCUC establish a deferral cost for the Duke Point Power Plant that can be used as the basis for deferral payments to Sea Breeze for implementation of this solution.

It should be noted that this transmission line is well under way with the full permitting process already commenced and the appropriate agencies involved. Financing for this project is also in an advanced stage with a commitment offer for the project equity. The in service date of Fall 2007 is backed by an offer from ABB for an EPC contract with the full corporate and engineering capability of ABB behind it.

The cost of a wheeling charge across the Juan de Fuca and acquiring the energy, either through repatriation of energy already owned by BC Hydro, or through purchases from an energy rich BPA system, will be considerably less than the cost of energy from the Duke Point Plant with the included exposure to twenty five years of gas price risk and subsidy payments from the Province to a non-public company. There also exists the possibility, which Sea Breeze is open to, of rolling the wheeling charge into either BPA's or BCTC's overall tariff. Should this option be exercised, the overall cost of supplying energy and serving reliability needs through supplying capacity would be additionally reduced.

Therefore, Sea Breeze Pacific would also like the BCUC to consider the cost of the tolling option in its deferral considerations for energy transfers to V.I.

Given that the Utility Commission was created and empowered in its function as the representative of the ratepayers, to guarantee that monopoly powers are not abused, Sea Breeze Pacific believes that it is incumbent upon the Commission, under its charter, to reject the entire terms of a Call for Tenders that deliberately excludes potential solutions. How can one adhere to the concept of least cost to the rate base when solutions are arbitrarily rejected from consideration without analysis? The rationale that was brought to bear to reject transmission options was that BC Hydro required "on island" generation. Importing gas from off island does not strike us as an "on island" solution and there is certainly no material difference from a security of supply point of view to importing electrons or importing molecules. Additionally, as noted above, the forced outage rate of transmission is superior to gas generation and therefore there is a material difference between the reliability issues surrounding the two different solutions; a difference that clearly indicates that transmission is superior.

Sea Breeze would strongly advise the commission to reject the application for an EPA on the basis that it is neither mandatory for reliability nor cost effective.

<u>Summary of the results of the BPA feasibility study:</u>

The Juan de Fuca Project One is scheduled to be energized in the fall of 2007.

The BPA feasibility study indicates that the potential transfer capacity of this line, according to the pre-contingency cases, could be 550 megawatts North to South, 400 megawatts export from the Olympic Peninsula (South to North) to Vancouver Island.

In mitigating first contingency problems, even if the least cost and least desirable Remedial Action Scheme (RAS) scheme is used, the transmission option will be superior to a generator because the forced outage rate of transmission is much lower than any type of generation, especially an internal combustion gas-fired unit like Duke Point.

The Juan de Fuca Project Two of 550 megawatts is planned to be energized in late summer 2008. Coupled with our planned first contingency mitigation strategies and the creative system enhancements we propose, this should provide full 1,100 MW transfer capacity both south to north and north to south.

<u>Summary from the Sea Breeze Pacific corporate point of view:</u>

Given the indicated potential capacity south to north by the pre-contingency results, we believe that the Duke Point Power Plant is not required for capacity needed to satisfy reliability criteria between 2007 and the implementation of BCTC's 230 kV AC transmission solution or Sea Breeze Pacific's alternate HVDC Light solution for reinforcement between the mainland and Vancouver Island.

If we had been allowed to compete on a fair basis in the VI call for tenders where our transmission based options were excluded by BC Hydro, we would have demonstrated a lower cost, higher reliability option. Therefore, we should now be granted capacity and energy deferral benefits as BPA and the USA utilities have agreed we are entitled to and have offered us for proceeding with this exceptional interconnection project.

Additional study and verification of these results, as per FERC 2003-A rules, will be completed over the next 90 days and will establish what the ultimate maximum export capacity will be. The enclosed feasibility study is abridged as per security and corporate non-disclosure requirements. The full study can be sourced from BPA by qualified entities. The abridged elements of the report are the base case data sets and the nomograms. Access to these elements would require registration with WECC as per Code of Conduct considerations.

Should you have any questions, or require additional information, please feel free to contact me at (604) 689-2991 Local 224.

Sincerely,
Sea Breeze Pacific Regional Transmission System Inc.

per: Anthony O. Duggleby
President & C.E.O.

cc: Intervenors
encl. Feasibility Study for Sea Breeze, text only version

Feasibility Study for Seabreeze DC Interconnection

Issued: Jan 25, 2005

Prepared for: **Bonneville Power Administration**

Submitted by:

Electric Systems Consulting
ABB Inc.
940 Main Campus Drive, Suite 300
Raleigh, NC 27606

Legal Notice

Feasibility Study for Seabreeze DC Interconnection	Dept. Consulting	Date 1/25/04	Pages 67

Author:	Reviewed by:	Approved by:
John Daniel	Don Martin	Willie Wong

Summary

Seabreeze submitted an interconnection request to BPA for a DC terminal in the Port Angeles/Fairmount area from either Vancouver Island or Ingledow. To assess the feasibility of the interconnection, BPA requested ABB Electrical System Consulting to develop nomograms indicating acceptable DC terminal operating conditions considering the effects on the Olympia Peninsula transmission system (primarily 230kV and 115kV).

Power flow cases for a large number of operating conditions were used to develop the nomograms. A variety of system parameters were also considered including seasonal load participation factors, DC power levels for both importing (at Port Angeles) and exporting power (from Port Angeles Vancouver Island), and system contingency sets.

The results indicated that under pre-contingency system conditions, a large range of different DC power level vs. load level conditions, will not cause facility overloads or bus voltage violations. This range is significantly reduced following planning contingencies. In most cases branch overloading was the limiting criteria.

One branch that regularly experienced overloads was the Fairmont 115/230kV transformer. The effect of increasing the transformer rating to 200MVA was investigated and found to increase acceptable operating areas for pre-contingency) system conditions, but was less effective under contingency conditions. Increasing the reactive compensation at Foss Center and Valley Junction, while also converting it to switched compensation was found to help alleviate bus undervoltages created by a bus fault at the Kitsap 115kV bus.

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1 Introduction

Seabreeze submitted an interconnection request to BPA for a DC terminal in the Port Angeles/Fairmont area. To assesss the feasibility of the interconnection, BPA requested ABB Electrical System Consulting to develop nomograms indicating acceptable DC terminal operating points considering the effects on the Olympia Peninsula transmission system (primarily 230kV and 115kV). To examine the most limiting conditions the total HVDC interconnection was connected to Port Angeles in this study.

This report discusses the general criteria and assumptions used in the development of the nomograms. It also presents conclusions that can be inferred from the study results.

Power flow cases for a large number of system operating conditions have been used for the nomogram development. Several system parameters have been considered including seasonal load participation factors, DC power levels for both importing (at Port Angeles) and exporting power (from Port Angeles), and system contingency sets. Nomograms considering thermal overloads only and thermal overloads plus operating voltage criteria violations have been developed. Evaluations have been made to determine potential solutions to the voltage criteria violations and transformer overload limitations.

2 Operational Nomograms

A large number of power flow cases have been performed in order to develop each nomogram. The power flow program used for this study is PSS/E which has long been recognized as an industry standard for power flow calculations. Each power flow case considered a unique set of system conditions and the results have been used to develop several sets of nomgrams which indicate the areas of load power level vs. DC terminal power level for which acceptable operating conditions on the Olympia Peninsula transmission system are maintained. Acceptable operation is defined as a load power / DC power combination under which no violation of limit criteria exists.

2.1 Nomogram Parameters

The nomograms have been developed with a different parameter settings applied to each. The following parameters were considered

- DC Power Level
- Seasonal Load Base
- Peninsula Load Level
- Contingency Sets
- Limit criteria

Each is briefly considered below.

2.1.1 DC Power Level

The DC terminal is modeled at the Port Angeles 230kV bus. For each nomogram attempts were made to find power flow solutions for DC terminal power levels ranging from -1000MW (exporting power from Port Angeles) to +1000MW (importing power at Port Angeles). The DC power level was varied in steps of 50MW.

Two types of DC converters have been modeled for consideration: 1) a conventional DC converter which supplies AC power at unity power factor (pf=1.0); and, 2) a voltage source DC converter that is capable of supplying variable and controllable reactive power in addition to the real power.

2.1.2 Seasonal Load Base

The electrical loads seen at the various buses in the Olympia Peninsula system change with the seasons. The base winter load is approximately 1150MW while the base summer load is approximately 600MW.

The behavior of the loads also vary with season due to the mixture of industrial and residential loads, and due to seasonal differences in the load power factors. In order to properly account for the variations in load, summer and winter have been considered independently. Load participation factors have also been considered for each season to define how the loads at the various buses contribute to a change the overall Peninsula load. The participation factors are discussed further in Appendix A.

2.1.3 Peninsula Load Level

Starting from the seasonal base load, each nomogram considers a range of load levels, varied in steps of 25MW. For the summer cases, load levels ranging from 300MW to 800MW have been considered. For the winter cases, load levels ranging from 550MW to 1250MW have been considered. The higher load level cases can account for potential future load growth.or also represents abnormal ambient conditions without load growth.

2.1.4 Contingency Sets

BPA provided two sets of contingencies to be used in evaluating the system behavior – single contingencies and common mode contingencies. Twenty-five (25) single contingencies considering single branch outages were provided. Twenty-eight (28) common mode contingencies – which consider all of the line outages that would occur for a given bus fault – were provided. These contingencies are listed in Appendix B.

In addition to nomograms representing each contingency set, base nomograms considering the full pre-contingency conditions are provided.

2.1.5 Limit Criteria

Two sets of limit criteria have been applied for the development of different nomograms. Any operating condition under which the selected limit criteria is violated is considered unacceptable. The two limit criteria sets are:

- Branch overloads only. Any branch experiencing a current level in excess of it's 100% Base A rating is considered overloaded. Nomograms developed with this criteria applied can be considered as representing the latent system capability.
- Branch overloads plus operating voltage criteria violations. The acceptable voltage range for all cases is 95% to 105% of the nominal bus voltage. Any bus experiencing a voltage less than 95% or over 105% is considered in violation of the limit criteria.

It should be noted that the power flow cases have been performed assuming ideal voltage control at the buses with shunt capacitors. That is, the shunts were considered continuously variable instead of changing in discrete steps.

2.2 Existing System Nomograms

Table 1 lists the specific nomograms that have been developed using the model the existing Olympia Peninsula transmission system and describes the parameters used to develop each nomogram. The actual nomogram plots are given following the conclusions in Figure 1 through Figure 24

For each nomogram a list that indicates the limiting violations is provided in Appendix C. The list indicates all unacceptable DC power / load level combination immediately adjacent to an acceptable DC power / load level combination. It also provides information on the violations. For conditions where multiple contingencies result in criteria violations only the most severe violation is indicated.

Table 1 – Existing System Nomogram List

Figure #	Description	Season	DC term pf	Contingency Set	Limit Criteria
1	Base System	Summer	1.0	--	Overload
2	Base System	Summer	1.0	--	All
3	Contingency Set	Summer	1.0	Single	Overload
4	Contingency Set	Summer	1.0	Single	All
5	Contingency Set	Summer	1.0	Common Mode	Overload
6	Contingency Set	Summer	1.0	Common Mode	All
7	Base System	Summer	Var	--	Overload
8	Base System	Summer	Var	--	All
9	Contingency Set	Summer	Var	Single	Overload
10	Contingency Set	Summer	Var	Single	All
11	Contingency Set	Summer	Var	Common Mode	Overload
12	Contingency Set	Summer	Var	Common Mode	All
13	Base System	Winter	1.0	--	Overload
14	Base System	Winter	1.0	--	All
15	Contingency Set	Winter	1.0	Single	Overload
16	Contingency Set	Winter	1.0	Single	All
17	Contingency Set	Winter	1.0	Common Mode	Overload
18	Contingency Set	Winter	1.0	Common Mode	All
19	Base System	Winter	Var	--	Overload
20	Base System	Winter	Var	--	All
21	Contingency Set	Winter	Var	Single	Overload
22	Contingency Set	Winter	Var	Single	All
23	Contingency Set	Winter	Var	Common Mode	Overload
24	Contingency Set	Winter	Var	Common Mode	All

3 Nomogram Analysis

Several observations can be made from an analysis of the existing system nomograms and the limiting violations for each

1. The results indicated that under pre-contingency system conditions, a large range of DC power level vs. load level conditions, will not cause facility overloads or bus voltage violations when connected to the Port Angeles 230kV bus. There are thermal limits which are reached at approximately 750 to 800MW importing (at Port Angeles) in the summer, but the DC power level can reach 1000MW for many load conditions in the winter. The exporting power (from Port Angeles) limits are reached at between -400MW and -600MW depending on the Peninsula load for both seasons.
2. The contingencies significantly reduce the acceptable operating areas. As expected, the common mode contingencies are more severe and in some instances (e.g. common mode contingencies 6 and 19) result in no acceptable operating points. It may be necessary to allow the DC power to be ramped back, or allow the northern peninsula to be islanded on the HVDC Light terminals, under some severe contingencies. This consideration should be investigated in future studies.
3. In general the HVDC converter that is capable of supplying reactive compensation at the Port Angeles 230kV bus more readily avoids voltage criteria violations.

4. Under most base case system and single contingency cases the limiting criteria are branch overloads. In several cases, the only branch overload observed is the Fairmont 115kV – Fairmont 230kV. This suggests a system enhancement which was explored below.
5. Where branch overloads were not exclusively associated with the Fairmont transformer, transmission lines are involved. The overload conditions for operating points adjacent to acceptable operating points are generally small (<110%), but increase for greater DC import or export powers.

   The more common branch overloads are observed on the following lines, depending on the contingency.

   - Happy Valley 230 – Port Angeles 2 230
   - Fairmont 230 – Happy Valley 230
   - Fairmont 115 – Shelton 115
   - Olympia 230 – Shelton 230

   Future studies could consider means of reducing the overloads on these branches, including a division of the DC power between multiple buses – e.g. Port Angeles 230 and Fairmont 230.
6. For single contingency cases where the limiting criteria are voltage violations, most of these violations can likely be corrected by an appropriate minor adjustment in selected transformer tap setting.
7. The most severe of the common mode contingencies often result in power flow cases that will not converge or result in voltage collapse conditions in portions of the Olympia Peninsula system.

3.1 System Enhancement Nomograms

3.1.1 Fairmont 115/230kV Transformer Rating

As previously stated, the results indicate that the Fairmont 115/230kV transformer often limits the acceptable DC power level. In almost all of these cases it limited the amount of power that can be imported to the Olympia Peninsula. Additional cases were run to evaluate the effect of increasing the transformer rating from 100MVA to 200MVA. The transformer impedance as taken on the transformer rating base was assumed to remain constant.

This change increases the acceptable import operating area for the base case system in the winter at higher load levels. It had little effect on the summer operating area or on any of the contingency operating ranges which are limited by other branches.

The improved winter base nomogram is provided in Figure 25. Additional improvement would be expected from a transformer rating above 200MVA.

3.1.2 Foss Center / Valley Junction Capacitors

Also noted above was the severity of common mode contingency 06. This contingency simulates a bus fault on the Kitsap 115kV bus with the loss of all lines from that bus. For winter cases under this contingency, all of the remaining 115kV buses in the S. Bremerton/Valley Junction/Foss Center region experience undervoltages around 0.9pu or lower. The capacitors at the Foss Center 115kV bus and the Valley Junction 115kV bus were modified so that they had continuous control with a voltage set point of 1.025pu. They were also increased to permit 80MVAr of shunt capacitors at each bus. These changes allowed the buses in the problem region to maintain acceptable voltages for those operating points which were not otherwise limited by overloads. The nomograms for both the overload limits and all limits are shown in Figure 26 and Figure 27 respectively.

4 Conclusions

Applying a DC terminal at the Port Angeles 230kV bus is feasible for a large potential range of system operating conditions for both summer load conditions and winter load conditions. Exporting power (from Port Angeles), under pre-contingency conditions and this study's assumptions, is possible to DC power levels of 400MW or more depending on the load levels. Importing power (at Port Angeles), under pre-contingency conditions and this study's assumptions, is possible to DC power levels as high as 800MW in the summer and 1000MW in the winter depending on load levels.

The limiting criteria are generally branch overloads on nearby 230kV and 115kV lines. Overloads on the Fairmont 115/230kV transformer also limit several operating conditions. Increasing the transformer rating to 200MVA alleviates many of these limitations.

Limits related to voltage criteria violations are more readily avoided if the DC converter can provide reactive support to the Port Angeles 230kV bus.

Under contingency events, the acceptable operating area is significantly reduced – primarily by line overloads. Under these conditions it may be required to ramp back the DC power. This consideration and options to relieve the most commonly overloaded lines should be examined in future studies.

One of the most severe common mode contingencies is a bus fault at the Kitsap 115kV bus. The Kitsap 115 bus fault results in deep undervoltages on the 115kV system near South Bremerton, Foss Center, and Valley Junction. An increase of the capacitors at Foss Center and Valley Junction to 80MVAr each alleviates these undervoltages for several operating points.