Expected Energy Not Served (EENS) Study for Vancouver Island Transmission Reinforcement Project

(Part IV: Effects of Existing HVDC on VI Power Supply Reliability)

January 9, 2006

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Expected Energy Not Served (EENS) Study for Vancouver Island Transmission Reinforcement Project (Part IV: Effects of Existing HVDC on VI Power Supply Reliability) (Executive Summary)

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The VITR is planned to be in service in 2008 but may be delayed by one or even two years. If the VITR is delayed, VI power supply has to continuously reply on the existing HVDC system although it has reached the end-of-life stage. The planning capacity of the existing HVDC system after 2007 is zero but it can be continuously used from an operational viewpoint.

The purpose of the study in this part of the report is to investigate effects of the existing HVDC on Vancouver Island power supply system reliability before and after 2008 (the year of the VITR in service). It also quantifies the increased risk (in terms of EENS) of the VI power supply system if the VITR is delayed and the positive impact of replacing the smoothing reactor at VIT and using the old one as an on-site spare on the improvement of EENS during the VITR delay.

The quantified EENS studies indicate:

- Before the 230 kV line in service, the existing HVDC system can greatly reduce the EENS while after the 230 kV line in service, the HVDC will provide a limited improvement in the EENS, which is less than 20% each year on the average compared to the case before the 230 kV line in service. Also, the improvement will be decreased with the years. The results suggest that the existing HVDC should be retired immediately or in a couple of years after the 230 kV line is in service.
- If the 230 kV line is delayed, the existing HVDC system has to be continuously operated. However, this will result in a much higher risk for VI power supply than using the 230 kV line.
- Replacing the HVDC pole 2 reactor at VIT and using the old one as an on-site spare is a short-term measure to improve the availability of the HVDC and thus the reliability to VI power supply. However, the effect of this enhancement is limited and is only equivalent to delaying deterioration in VI power supply reliability by one year.
- The 4 numbers of unit interruption costs, which are based on different customer surveys and/or were used in reliability evaluation for system planning at BC Hydro in the past, are utilized to estimate risk costs due to the EENS. The annual total cost, which are the sum of annual capital investment, OMA and risk costs, for the 230 kV line option is lower than that for the option of continuously using the existing HVDC in 2008 to 2009. The difference will be increased as time advances because of increasing failure probability of the aged HVDC.

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1. Introduction

A report titled "Reliability Evaluation of Three Scenarios for Vancouver Island Power Supply – An Expected Energy Not Served (EENS) Study" was released for the VIGP project in June 11, 2003 [1]. In that report, three scenarios of VIGP (Portfolio 2), 230 kV line and HVDC life extension were evaluated and compared. Based on various technical studies and the VIGP hearing, it was decided to go ahead with the 230 kV line, which is called the Vancouver Island Transmission Reinforcement project (VITR).

The VITR is planned to be in service in 2008 but may be delayed by one or even two years. If the VITR is delayed, VI power supply has to continuously reply on the existing HVDC system although it has reached the end-of-life stage. The planning capacity of the existing HVDC system after 2007 is zero but it can be continuously used from an operational viewpoint.

Another report titled "Probability Distribution of HVDC Capacity and Impacts of Two Key Components" was prepared by BCTC in May 2, 2004 [2]. The report assessed state probabilities of HVDC Poles 1 and 2 being at its zero, half and full capacities using a detailed HVDC model. These probabilities are used as input data in this study. The results in the report also show that smoothing reactors and filter capacitors are critical components for Pole 2 reliability. In the existing HVDC system, there is only one spare of smoothing reactor, which is located at the ARN side. If the smoothing reactor at the ARN fails, it takes only 8 hours to replace it whereas if the smoothing reactor at the VIT side fails, it will take about one month to transport the spare from ARN to VIT and replace it. Therefore if the smoothing reactor at VIT is replaced by a new one and the old one is used as an on-site spare, the availability of Pole 2 and thus the whole HVDC system will be improved. The report quantified the increased probabilities of Pole 2 being at its derated and full capacities due to the new smoothing reactor at VIT. This data is also used in this study.

The purpose of the study in this part of the report is to investigate effects of the existing HVDC on Vancouver Island power supply system reliability before and after 2008 (the year of the VITR in service). It also quantifies the increased risk (in terms of EENS) of the VI power supply system if the VITR is delayed and the positive impact of replacing the smoothing reactor at VIT and using the old one as an on-site spare on the improvement of EENS during the VITR delay.

2. Method, Computing Tool and Model

The method is to evaluate EENS indices for Vancouver Island power supply system with and without the existing HVDC. The difference between the cases with and without the existing

HVDC represents the effect of the HVDC. Intuitively, it is obvious that the effect of the existing HVDC is different before and after the 230 kV line is in service.

The computing tool used in the study is still the MCGSR program. The number of samples used in the study was 100,000 for each load level in the 15-step load model.

The EENS evaluation model for Vancouver Island power supply is shown in Figure 1. The 500 kV lines, 230 kV line, existing HVDC and on-Island generating units were modeled. All components except the HVDC were represented using two-state (up and down states) random variables. The common cause failure of the two 500 kV lines due to lightning was simulated using an independent random variable. The HVDC includes Pole 1 and Pole 2 and both poles reached their end-of-life stage with a degraded capacity and high unavailability. In the study, both the poles are represented using three-state (up, derated and down states) random variables with the probabilities that are evaluated in Reference 2. The following cases are considered:

- Before the 230 kV line in service (2006 and 2007)
    - Without the existing HVDC
    - With the existing HVDC

- After the 230 kV line in service (2008 to 2010)
    - Without the existing HVDC
    - With the existing HVDC

- The existing system (230 kV line delayed) (2006 to 2010)
    - With the existing HVDC (no enhancement)
    - With the existing HVDC with the new reactor at ARN

3. Data

3.1 Failure data

The failure data for the 500 kV lines and on-Island generating units were based on historical failure records. The failure data for a new 230 kV AC line includes two portions for overhead line and submarine cable. The failure data for the overhead portion were based on the average of existing 230 kV lines in the BC Hydro system, which were obtained from BCTC's CROW (Control Room Operations Window) system. The failure data for the submarine cable were based on an engineering estimate. This is a relatively pessimistic estimate since the repair time is assumed to be 3 months (2190 hours) considering that repair activities under water will be extremely difficult. The failure data of the phase shift transformer (PST) that is in series with the 230 kV line is based on historical failure records of the PST on 2L112 in the HC Hydro system. All these data are the same as those used in the other parts of the report and are given in Appendix A and B.

The capacity state probabilities of the existing HVDC system are obtained from the previous report [2] and presented in Tables 1, 2 and 3 respectively. Note that the unavailability of Poles 1 and 2 (probabilities at zero MW capacity) increases with years. This is due to the aging failure mode of aged HVDC components.

3.2 Load data

The load model used in the study was the most recent Vancouver Island peak load forecast for 2006/07 to 2010/2011. The 8760 hourly load records in 2004 were used to model the annual load curve shape. The peak load forecast and the total VI generation MW are given in Appendix C.

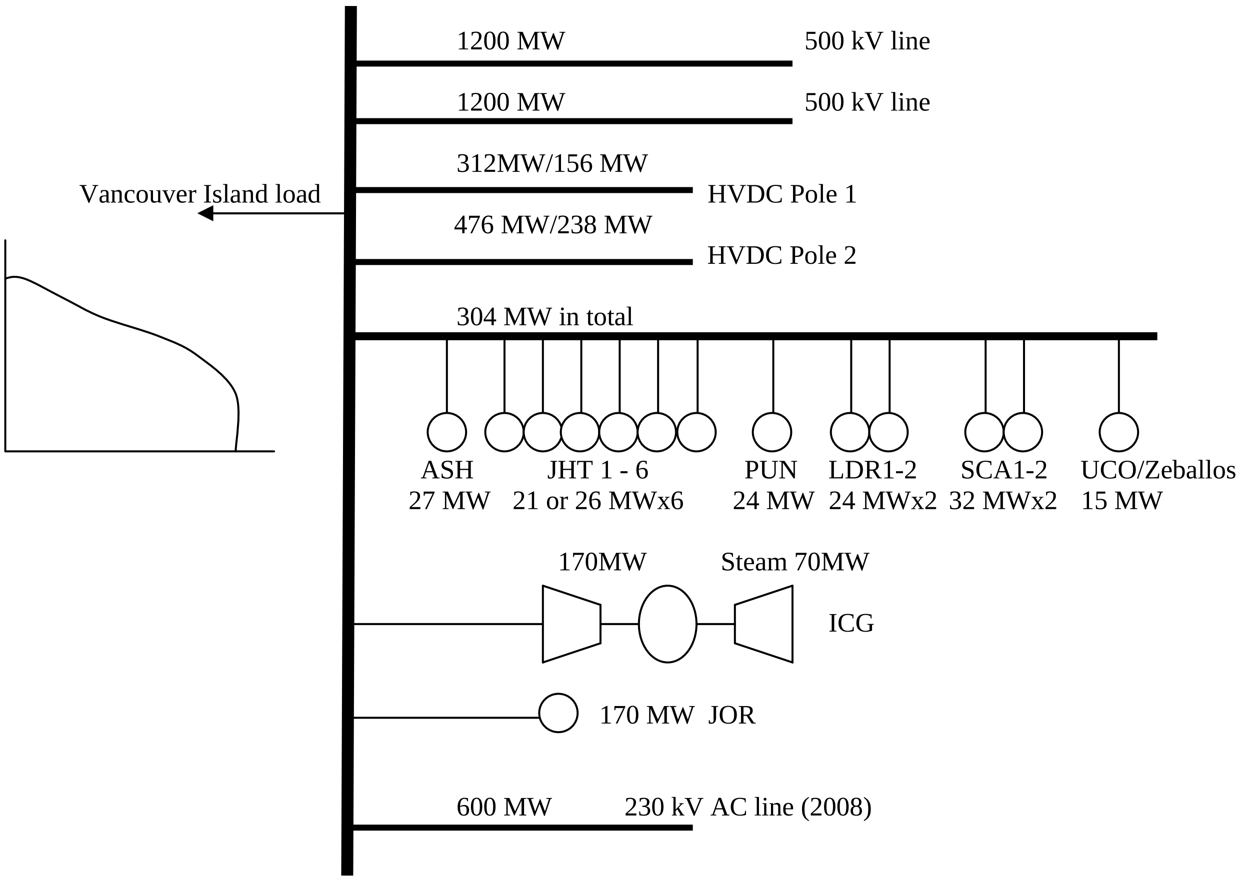

Figure 1 EENS Evaluation Model for Vancouver Island supply

Table 1 Capacity state probabilities of Pole 1

Year	Probability at zero MW	Probability at 312 MW	Probability at 156 MW
2006	0.741321762	0.106243735	0.152434503
2007	0.799520435	0.075725132	0.124754433
2008	0.851684374	0.051009050	0.097306577
2009	0.894919895	0.032753449	0.072326656
2010	0.929180460	0.019887959	0.050931581

Table 2 Capacity state probabilities of Pole 2

Year	Probability at zero MW	Probability at 476 MW	Probability at 238 MW
2006	0.228669507	0.554333069	0.216997424
2007	0.269917187	0.512838492	0.217244321
2008	0.317942876	0.463541606	0.218515517
2009	0.370088431	0.413689862	0.216221708
2010	0.426642113	0.362198344	0.211159543

Table 3 Capacity state probabilities of Pole 2 with a new reactor at VIT

Year	Probability at zero MW	Probability at 476 MW	Probability at 238 MW
2006	0.162611461	0.601807089	0.235581450
2007	0.192842440	0.566978784	0.240178776
2008	0.229607402	0.523576413	0.246816185
2009	0.270448205	0.479127858	0.250423937
2010	0.316306022	0.431899224	0.251794754

4. Study Conditions

- The time frame in the study is 5 years from 2006 to 2010. The 230 kV line is assumed to be in service in 2008.

- The local transmission network on Vancouver Island (including network constraints and failures of network components) was not included in the model. Also, the grid system at the Lower Mainland side has been assumed to be perfect and was not incorporated into the study. These assumptions do not cause any negative impact on the results since the focus is the EENS indices to Vancouver Island supply.

- The peak loads from 2006 to 2010 were based on the most recent load forecast (December 2005) while the annual load curves for all the 5 years under the study follow the same shape that is based on the hourly load records in 2004.

- Both poles 1 and 2 of HVDC were modeled using three capacity states (full up, derated to half and full down).

- The phase shifting transformer (PST) was modeled by assuming that it is in series with the 230 kV line and no bypass operation for the PST. This is a pessimistic assumption because in real life, when the PST fails, it can be bypassed and the 230 kV line will continue to supply in most cases according to the design.

- The capacity of two 500 kV lines is assumed to be the continuing rating (1200 MW). A short time (2 hours) overloading capacity (1300 MW) is not considered since the repair time used in the simulation (138 hours) is much longer than 2 hours. In other words, considering a 100

MW higher capacity for only 2 hours will not have effective impacts on the results for one year's simulation. Also, the same 500 kV line capacity is used in all the cases for comparison.

5. EENS Evaluation

(1) Comparison between the cases with and without HVDC

The cases with and without the HVDC before (2006 and 2007) and after (2008 to 2010) the 230 kV line in service are evaluated. The difference between the two cases with and without the HVDC reflects the benefit from the HVDC. The EENS indices for the comparisons before and after the 230 kV line in service are shown in Tables 4 and 5 respectively. It can be seen that before the 230 kV line in service, the existing HVDC system can greatly reduce the EENS while after the 230 kV line in service, the HVDC will provide a limited improvement in the EENS, which is less than 20% each year on the average compared to the case before the 230 kV line in service. Also, the improvement will be decreased with the years. The results indicate that the existing HVDC should be retired once the 230 kV line is in service.

It is noted that in the case without the HVDC, the EENS has a slight decrease in 2009. This is due to the additional local generation capacity of 30 MW in 2009. However, this effect does not show off for the case with the HVDC since the HVDC has a much higher capacity than 30 MW.

Table 4 EENS (MWh/year) before the 230 kV line in service

Year	Without HVDC	With HVDC	Difference
2006	13016	4850	8166
2007	13839	5655	8184
Total	26855	10505	16350

Table 5 EENS (MWh/year) after the 230 kV line in service

Year	Without HVDC	With HVDC	Difference
2008	2870	1140	1730
2009	2779	1271	1508
2010	2969	1542	1427
Total	8618	3953	4665

(2) Comparison between the HVDC and 230 kV line

The 230 kV line may be delayed by one or even two years. In this case, the existing HVDC system has to be continuously operated. The EENS indices for using the HVDC and 230 kV line are given in Table 6. It can be seen that continuously using the HVDC will result in a much higher risk for VI power supply than using the 230 kV line.

Table 6 EENS (MWh/year) for the HVDC and 230 kV line after 2007

Year	Existing HVDC	230 kV line	Difference
2008	6677	2870	3807
2009	7261	2779	4482
2010	8809	2969	5840
Total	22747	8618	14129

(3) Effect of a new smoothing reactor at VIT for the HVDC pole 2

If the VITR is delayed and the existing HVDC is continuously operated for a few more years, replacing the HVDC pole 2 reactor at VIT and using the old one as an on-site spare is a short-term measure to improve the availability of the HVDC and thus the reliability to VI power supply. The EENS indices for the existing HVDC without enhancement and with replacing the pole 2 reactor at VIT are shown in Table 7. It can be seen that the reduction in the EENS due to replacing the pole 2 reactor at VIT and using the old one as an on-site spare is almost equivalent to delaying deterioration in VI power supply reliability by one year. This result is consistent with that obtained in the report of "Probability Distribution of HVDC Capacity and Impacts of Two Key Components", in May 2004 [2].

Table 7 EENS (MWh/year) for the HVDC with and without enhancement

Year	Without enhancement	With enhancement	Difference
2007	5655	5002	653
2008	6677	5858	819
2009	7261	6207	1054
2010	8809	7478	1331
Total	28402	24545	3857

6. Economic Analysis

This section provides an economic comparison including reliability worth between the existing HVDC and 230 kV line. The comparison focuses on a short-term period (2008 to 2010). The purpose is to provide information on whether there exits any economic benefit for extending use of the existing HVDC and delaying the VITR for a couple of years. The long term comparison between the 230 kV line and HVDC life extension was performed in the VIGP project including the reliability analysis [1].

6.1 Unit interruption cost

The risk cost of VI power supply system is a component in the overall economic analysis. The risk cost is equal to the product of EENS (MWh/year) and unit interruption cost ($/kWh). Determination of unit interruption cost has been a challenge in the power industry for years. The main difficulty is uncertainty in raw data. Several raw data sources are given below.

(1) Reference 3 (Chapter 7) provided a composite customer damage function, which is based on a wide range of investigations across the Canada about 20 years ago. The customer damage function is expressed in $/kW and duration as shown in Table 8. It can be converted to $/kWh as shown in Table 9.

Table 8 Composite customer damage function in $/kW

Interruption Duration	Interruption cost ($/kW)
20 min	1.56
1 hour	3.85
4 hours	12.14
8 hours	29.41

Table 9 Composite customer damage function in $/kWh

Interruption Duration	Interruption cost ($/kWh)
20 min	4.68
1 hour	3.85
4 hours	3.04
8 hours	3.68
Average	**3.81**

(2) Reference 4 provided the following information:
"BC Hydro used a value of $5.00/kWh for all projects intended to provide an improvement in reliability. The $5.00 is a Canadian dollar equivalent of a value produced by the Bonneville Power Administration through limited surveys."

(3) Reference 5 provided a transmission system planning example, in which a value of $6.3/kWh was used as the unit interruption cost in system risk assessment for economic comparisons between different alternatives and an initial 230 kV line addition option was rejected due to its ineffectiveness in the total cost including the risk cost.

(4) A customer survey across Canada was conducted by the Power System Research Group of the University of Saskatchewan with participation of all Canadian utilities and a report was released in 1993 [6]. Based on this survey, a customer damage function specific to the BC Hydro system was created and included in the "Capital Planning Guidelines" document of BC Hydro dated April 1, 1993 [7]. This customer damage function is shown in Table 10. Since the customer damage function is expressed in $/kW and by ranges of duration, the mid value of each duration range is used to convert it into the customer damage function in $/kWh, which is shown in Table 11. An average composite customer damage function for Vancouver Island can be calculated using the average unit interruption costs for three customer sectors in Table 11 and the customer sector percentages of Vancouver Island loads. The calculation process is given in Table 12.

Table 10 Customer damage function for different customer sectors in $/kW

Duration	Residential	Commercial	Industrial	Unknown mix
0 to 19 min.	0.2	11.4	5.5	1.9
20 to 59 min.	0.6	26.4	8.6	4.0
60 to 119 min.	2.8	40.1	19.6	8.5
120 to 239 min.	5.0	72.6	33.6	15.1
240 to 480 min.	7.2	147.6	52.1	26.5

Table 11 Customer damage function for different customer sectors in $/kWh

Duration	Residential	Commercial	Industrial	Unknown mix
10 min.	1.2	68.4	33.0	11.4
40 min.	0.9	39.6	12.9	6.0
90 min.	1.9	26.7	13.1	5.7
180 min.	1.7	24.2	11.2	5.0
360 min.	1.2	24.6	8.6	4.4
Average	1.38	36.7	15.76	6.5

Table 12 Composite customer damage function for Vancouver Island loads in $/kWh

	Residential	Commercial	Industrial	Composite value
Customer sectors in VI loads	52.36%	17.61%	30.03%	100%
Unit interruption cost ($/kWh)	1.38	36.7	15.76	
	0.72	6.46	4.73	**11.91**

6.2 Economic analysis

The economic analysis is to compare the total costs for the VITR project and continuous use of the existing HVDC system. The total cost is the sum of annual capital investment, OMA and risk costs. The annual capital cost for the 230 kV line is $16.89 million, which is based on the total capital investment of $207 million, a discount rate of 6%, economic life of 50 years for overhead line and economic life of 40 years for submarine cable. It is assumed that the existing HVDC has reached the end of its economic life and no annual capital cost is left over. The OMA of the HVDC is about $5 million per year. The OMA for the 230 kV line is marginal and neglected. The risk cost equals the unit interruption cost times the EENS index. It increases with the year since the EENS increases with the year.

It can be seen from the information given in Section 6.1 that the unit interruption cost is varied from different data sources due to inherent uncertainty in customer surveys. The 4 numbers of the unit interruption cost in Section 6.1 are used in calculating risk costs. The results of the economic analysis for 2008, 2009 and 2010 are presented in Tables 13, 14 and 15 respectively. The comparison in the total cost between the 230 kV line and existing HVDC for these three years are shown in Figures 2, 3 and 4 respectively.

Table 13 Economic analysis for the 230 kV line versus the existing HVDC in 2008

	Risk cost (M$)		Annual capital (M$)		OMA cost (M$)		Total cost (M$)		
UIC ($/kWh)	230 kv line	HVDC	230 kv line	HVDC	230 kV line	HVDC	230 kV line	HVDC	difference
3.81	10.93	25.44	16.89	0	0	5	27.82	30.44	2.61
5.00	14.35	33.39	16.89	0	0	5	31.24	38.39	7.15
6.30	18.08	42.07	16.89	0	0	5	34.97	47.07	12.09
11.91	34.18	79.52	16.89	0	0	5	51.07	84.52	33.45

Table 14 Economic analysis for the 230 kV line versus the existing HVDC in 2009

	Risk cost (M$)		Annual capital (M$)		OMA cost (M$)		Total cost (M$)		
UIC ($/kwh)	230 kv line	HVDC	230 kv line	HVDC	230 kV line	HVDC	230 kV line	HVDC	difference
3.81	10.59	27.66	16.89	0	0	5	27.48	32.66	5.19
5.00	13.90	36.31	16.89	0	0	5	30.79	41.31	10.52
6.30	17.51	45.74	16.89	0	0	5	34.40	50.74	16.35
11.91	33.10	86.48	16.89	0	0	5	49.99	91.48	41.49

Table 15 Economic analysis for the 230 kV line versus the existing HVDC in 2010

	Risk cost (M$)		Annual capital (M$)		OMA cost (M$)		Total cost (M$)		
UIC ($/kwh)	230 kv line	HVDC	230 kv line	HVDC	230 kV line	HVDC	230 kV line	HVDC	difference
3.81	11.31	33.56	16.89	0	0	5	28.20	38.56	10.36
5.00	14.85	44.05	16.89	0	0	5	31.74	49.05	17.31
6.30	18.70	55.50	16.89	0	0	5	35.59	60.50	24.90
11.91	35.36	104.92	16.89	0	0	5	52.25	109.92	57.66

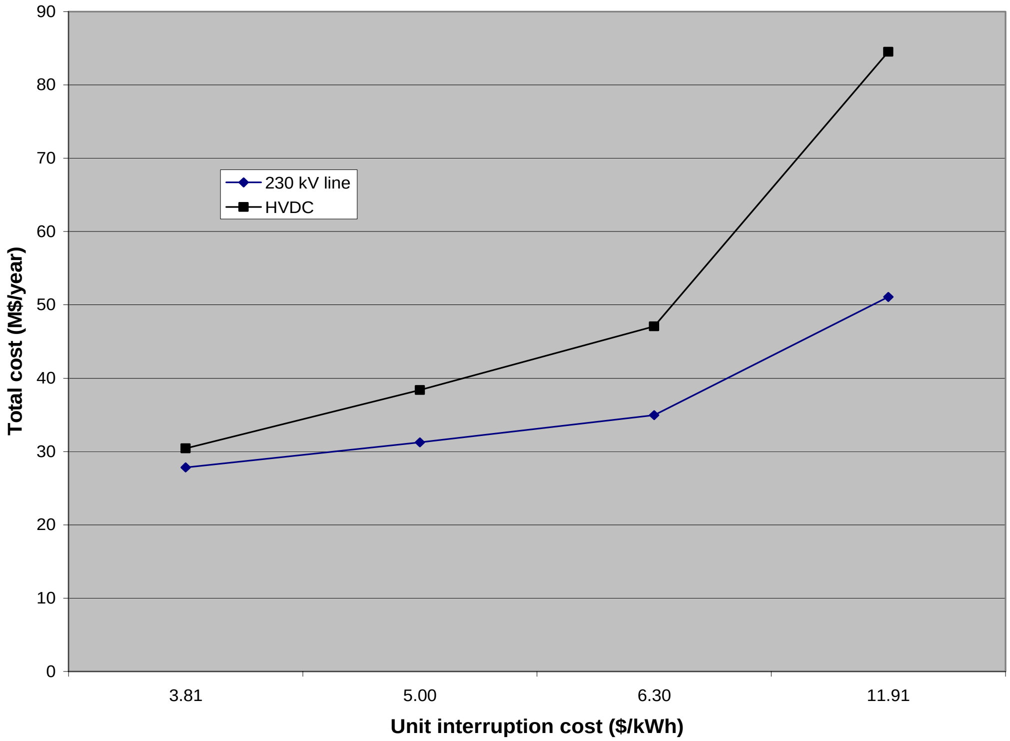

Fig. 2 Total cost of VITR and HVDC in 2008

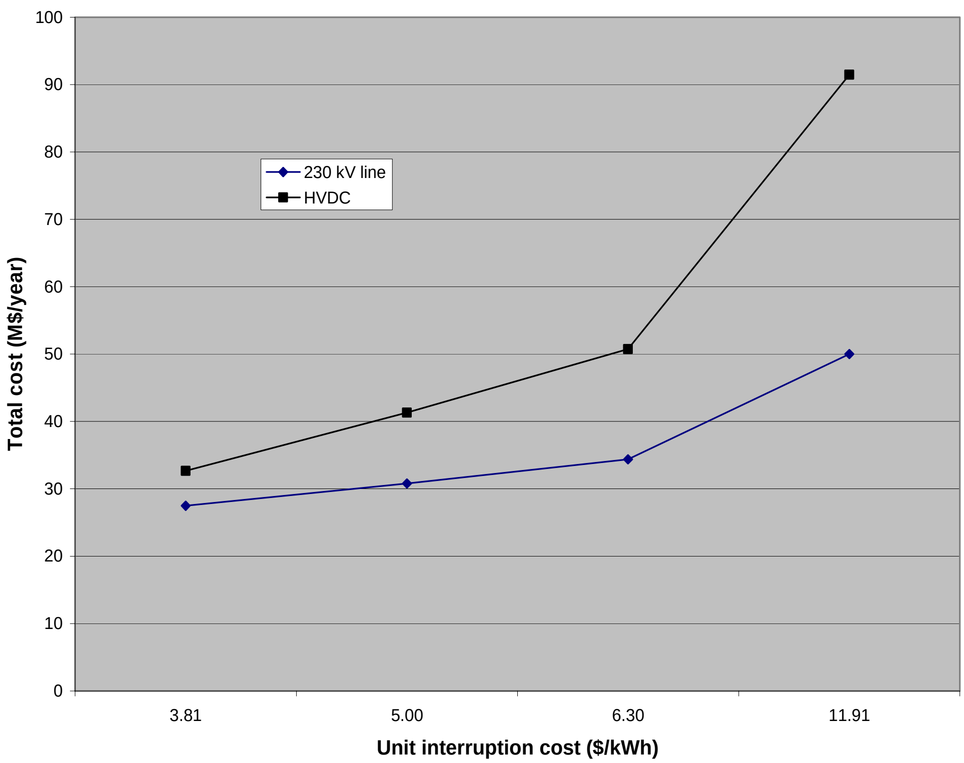

Fig. 3 Total cost of VITR and HVDC in 2009

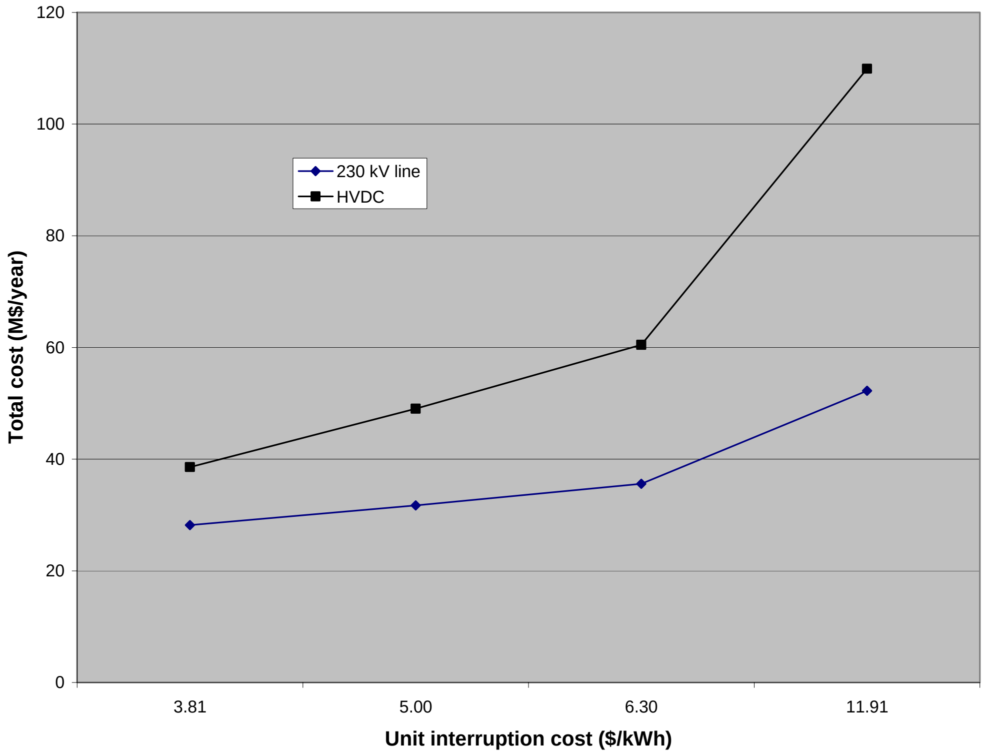

Fig. 4 Total cost of VITR and HVDC in 2010

7. Conclusions

This part of the report investigates effects of the existing HVDC on Vancouver Island power supply system reliability. The following observations are made:

- Before the 230 kV line in service, the existing HVDC system can greatly reduce the EENS while after the 230 kV line in service, the HVDC will provide a limited improvement in the EENS, which is less than 20% each year on the average compared to the case before the 230 kV line in service. Also, the improvement will be decreased with the years. The results suggest that the existing HVDC should be retired immediately or in a couple of years after the 230 kV line is in service.
- If the 230 kV line is delayed, the existing HVDC system has to be continuously operated. However, this will result in a much higher risk for VI power supply than using the 230 kV line.
- Replacing the HVDC pole 2 reactor at VIT and using the old one as an on-site spare is a short-term measure to improve the availability of the HVDC and thus the reliability to VI power supply. However, the effect of this enhancement is limited and is only equivalent to delaying deterioration in VI power supply reliability by one year.
- The 4 numbers of unit interruption costs, which are based on different customer surveys and/or were used in reliability evaluation for system planning at BC Hydro in the past, are utilized to estimate risk costs due to the EENS. The annual total cost, which are the sum of annual capital investment, OMA and risk costs, for the 230 kV line option is lower than that for the option of continuously using the existing HVDC in 2008 to 2009. The

difference will be increased as time advances because of increasing failure probability of the aged HVDC.

References

[1] BCTC Report, *Reliability Evaluation of Three Scenarios for Vancouver Island Power Supply – an Expected Energy Not Served (EENS) Study*, filed to BCUC in June 2003

[2] BCTC Report, *Probability Distribution of HVDC Capacity and Impacts of Two Key Components*, May 5, 2004

[3] R. Billinton and Wenyuan Li, *Reliability Assessment of Electric Power Systems Using Monte Carlo Methods*, Plenum Press, New York, 1994

[4] F. Turner, et al, "Reliability Worth: Development of A Relationship with Outage Magnitude, Duration and Frequency", CEA paper, March 1994

[5] Wenyuan Li, Y. Mansour, et al, "Application of Transmission Reliability Assessment in Probabilistic Planning of BC hydro Vancouver South Metro System", IEEE Transaction on Power Systems, 1995

[6] NSERC Report, Assessment of Reliability Worth in Electric Power systems in Canada, prepared by the Power System Research Group of University of Saskatchewan, June 1993

[7] BC Hydro Capital Planning Guidelines, November 1992

Appendix A: Local Generating Unit Reliability Data

Generating unit	Capacity (MW)	FOR	Repair time (hrs)
ASH	27	0.004	15.35
JHT-1	21 *	0.0795	926.51
JHT-2	21 *	0.0008	2.31
JHT-3	21 *	0.003	36.32
JHT-4	21 *	0.0026	7.84
JHT-5	21 *	0.0096	28.70
JHT-6	21 *	0.0003	3.77
PUN	24	0.0010	13.74
LDR-1	24	0.0063	19.15
LDR-2	24	0.0026	6.60
SCA-1	32	0.0027	5.33
SCA-2	32	0.0218	28.26
UCO/Zeballos	15	0.004	15.35
JOR	170	0.0124	5.99
ICG	240	0.1065 **	50.30 **
Total	714		

Note:

1. The reliability data for the local hydro generating units are based on historical outage records. These data are the same as those used in the following previous reports:

[1] BC Hydro technical report, "Reliability Assessment of Vancouver Island Supply 2000/01", Section 3 of "Vancouver Island Operation Plan 2000/01" produced by NOS (Network Operation Services), Grid Operation Division, BC Hydro, January 15, 2001

[2] BC Hydro technical, "Reliability Assessment for Vancouver Island Supply Options", produced by NPP (Network Performance Planning), BC Hydro, December, 2001

[3] BC Hydro technical report, "Probabilistic & Economic Assessment of HVDC Short-term Investment Strategies", produced by NOS (Network Operation Services), Grid Operation Division, BC Hydro, June 2002

2. * The 6 units at JHT are assumed to increase their capacity by 5 MW each by 2009/2010.
3. ** The failure data for the ICG are based on historical statistics from the NERC database for combined cycle turbine units from 1977 to 2001. The raw data can be found at http://www.nerc.com/~filez/gar.html. The breakdown of forced and planned failure data is as follows:

Unit	Capacity (MW)	Unavailability		Failure Frequency (f/year)		Repair time (hrs)	
		Forced	Planned	Forced	Planned	Forced	Planned
ICG	240	0.03238	0.07407	13.22	5.32	21.46	122.0

Appendix B: 500 kV Line and 230 kV Line Reliability Data

Line	Capacity (MW)	FOR	Repair time (hrs)
500 kV line	1200	0.0293	137.81
500 kV line	1200	0.0293	137.81
230 kV line	600	0.0259	383.74
Second 230 kV line	600	0.0259	383.74
Phase shift transformer	600	0.000116	3.06
Common cause failure of two 500 kV lines		0.0004	2.98

Note:

1. The reliability data for the 500 kV lines (including the common cause failure data) are the same as those used in the following previous reports:

[1] BC Hydro technical report, "Reliability Assessment of Vancouver Island Supply 2000/01", Section 3 of "Vancouver Island Operation Plan 2000/01" produced by NOS (Network Operation Services), Grid Operation Division, BC Hydro, January 15, 2001

[2] BC Hydro technical, "Reliability Assessment for Vancouver Island Supply Options", produced by NPP (Network Performance Planning), BC Hydro, December, 2001

[3] BC Hydro technical report, "Probabilistic & Economic Assessment of HVDC Short-term Investment Strategies", produced by NOS (Network Operation Services), Grid Operation Division, BC Hydro, June 2002

2. The common cause failure of two 500 kV lines refers to their simultaneous outage due to a common cause (lightning and terminal breaker failures).

3. The failure data of the phase shift transformer is based on historical failure records of the PST on 2L112 in the HC Hydro system. There were only 5 forced failures with a total of outage duration of 15.28 hours in the past 15 years since it was in service in 1990. This translates into the unavailability (FOR) of 0.000116, a forced failure frequency of 0.3333 failures /year and the repair time of 3.06 hours/repair.

4. The reliability data for the overhead portion of the new 230 kV line is based on the average of historical records of 230 kV lines in the BC Hydro system. The reliability data for the submarine portion is estimated as failure frequency=1/10 years and average repair time = 3 months. The total equivalent reliability data are calculated as follows (planned outage not considered):

Submarine portion:

f(cable)=1/10 years=0.1 f/year r(cable)=3 months =2190 hrs

FOR(cable)=f(cable)∗r(cable)/8760 =0.025

Overhead portion- Line-related failure

$f1=0.6945$ /year/ 100 km*40 km=0.2778/year $r1=16.85$ hours

Overhead portion- terminal-related failure

$f2=0.2136$ $r2=16.40$ hours

Overhead portion – total

f(overhead)=0.2778+0.2136=0.4914
r(overhead) = Σfr/Σf = (0.2778*16.85+0.2136*16.40)/(0.4914)=16.65

FOR(overhead)=f(overhead)*r(overhead)/8760 = 0.00093

The total reliability data for the new 230 kV line is estimated as:

FOR(total) = FOR(cable) +FOR(overhead) – FOR(cable)*FOR(overhead)

= 0.025+0.00093-0.025*0.00093 =0.02591

f(total) = 0.1+0.4914=0.5914

r(total) = FOR(total)*8760/f(total) = 0.02591*8760/0.5914 = 383.74 hours

Appendix C: Load forecast and resources balance for 2005/06 to 2025/26

Vancouver Island Demand and Resource Balance

(Based on the BC Hydro Dec 2005 load forecast)

	VI Demand	VI Dep_Gen*	500 kV	HVDC	1st cct	2nd cct	Balance
	MW	MW	MW	MW	MW	MW	MW
05/06	2318	698	1300	240			-80
06/07	2349	714	1300	240			-95
07/08	2370	714	1300				-355
08/09	2397	714	1300		600		217
09/10	2425	744	1300		600		219
10/11	2454	744	1300		600		190
11/12	2470	744	1300		600		174
12/13	2498	744	1300		600		146
13/14	2531	744	1300		600		113
14/15	2561	744	1300		600		83
15/16	2589	744	1300		600		55
16/17	2628	744	1300		600		16
17/18	2668	744	1300		600	600	576
18/19	2710	744	1300		600	600	534
19/20	2753	744	1300		600	600	491
20/21	2800	744	1300		600	600	444
21/22	2847	744	1300		600	600	397
22/23	2892	744	1300		600	600	352
23/24	2937	744	1300		600	600	307
24/25	2983	744	1300		600	600	260
25/26	3030	744	1300		600	600	214

* The VI dependable generations are assumed to be same as the previous (NITS2004 dependable resource).